ONE-HUNDRED EIGHTH REPORT

OF THE

NORTH CAROLINA

UTILITIES COMMISSION

ORDERS AND DECISIONS

Volume I

ISSUED FROM
JANUARY 1, 2018 THROUGH DECEMBER 31, 2018

ONE-HUNDRED EIGHTH REPORT
of the
NORTH CAROLINA UTILITIES COMMISSION

ORDERS AND DECISIONS

Issued from

January 1, 2018, through December 31, 2018

Edward S. Finley, Jr., Chairman

*Bryan E. Beatty, Commissioner

ToNola D. Brown-Bland, Commissioner

Jerry C. Dockham, Commissioner

James G. Patterson, Commissioner

Lyons Gray, Commissioner

Daniel G. Clodfelter, Commissioner

*Charlotte A. Mitchell, Commissioner

North Carolina Utilities Commission
Office of the Chief Clerk
M. Lynn Jarvis
4325 Mail Service Center
Raleigh, North Carolina 27699-4325

The Statistical and Analytical Report of the North Carolina Utilities Commission is printed separately from the volume of Orders and Decisions and will be available from the Office of the Chief Clerk of the North Carolina Utilities Commission upon order.

*Charlotte A. Mitchell was sworn in on January 26, 2018, replacing Bryan E. Beatty.

LETTER OF TRANSMITTAL

December 31, 2018

The Governor of North Carolina
Raleigh, North Carolina

Sir:

Pursuant to the provisions of Section 62-17(b) of the General Statutes of North Carolina, providing for the annual publication of the final decisions of the Utilities Commission on and after January 1, 2018, we hereby present for your consideration the report of the Commission's significant decisions for the 12-month period beginning January 1, 2018, and ending December 31, 2018.

The additional report provided under G.S. 62-17(a), comprising the statistical and analytical report of the Commission, is printed separately from this volume and will be transmitted immediately upon completion of printing.

Respectfully submitted,

NORTH CAROLINA UTILITIES COMMISSION

Edward S. Finley, Jr., Chairman

ToNola D. Brown-Bland, Commissioner

Jerry C. Dockham, Commissioner

James G. Patterson, Commissioner

Lyons Gray, Commissioner

Daniel G. Clodfelter, Commissioner

Charlotte A. Mitchell, Commissioner

M. Lynn Jarvis, Chief Clerk

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OF THE
NORTH CAROLINA UTILITIES COMMISSION

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DOCKET NO. M-100, SUB 147

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Amendment to Certain Rules	)))	ORDER AMENDING RULE R1-28 TO REQUIRE THREE-HOLE PUNCHED COPIES TO COURT REPORTER

BY THE COMMISSION: In an effort to provide for judicial economy and to assist the Court Reporter in the execution of duties, the Commission finds good cause to amend Rule R1-28(e) in Chapter 1, Practice and Procedure of the Commission's Rules and Regulations to require the 15 paper copies be three-hole punched.

IT IS, THEREFORE, ORDERED that current Commission Rule R1-28 is amended effective as of the date of this Order as set forth herein in Appendix A.

ISSUED BY ORDER OF THE COMMISSION.
This the 17th day of April, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

Commissioner Brown-Bland did not participate in this decision.

APPENDIX A

Rule R1-28. GIVING NOTICE OR FILING PAPERS WITH THE COMMISSION BY MAIL; ELECTRONIC FILING.

(a) Any notice, motion, pleading, or other document or paper may be filed with or served on the Commission by hand delivery, courier service, or United States mail, unless required by statute to be filed or served by some other means, but the same shall not be deemed filed or served until the day and date actually received at the office of the Commission in Raleigh. Rule R1-27 also applies to giving notice of filing papers by mail. In addition, any notice, motion, pleading, or other document may be electronically filed with the Commission using the Commission's online electronic filing system.

(b) An electronic filing may consist of one or multiple files, but all of the files in a filing must be either public or confidential and the filing so marked when made electronically. Except as provided in Section (e) below, do not file paper copies of documents that are filed electronically. Other provisions of any statute, rule, or order regarding the content and format of specific filings remain applicable.

(c) If filed electronically, post-hearing briefs, proposed findings of fact, and conclusions of law shall be filed in noncompressed editable Microsoft Word or ASCII Text format; where possible, all other documents filed electronically should also be filed in a noncompressed editable or searchable format rather than in an image file format.

(d) The typed characters representing the name of a person shall be sufficient to show that such person has signed the pleading or other document for purposes of electronic filing. Verification pages, when required, shall be printed, signed, notarized, converted to an electronic format, and included in the electronic filing as a separate file.

(e) The following documents should be filed electronically; provided, however, fifteen (15) three-hole punched paper copies of the entire filing, one of which shall be single-sided, must be provided to the Commission on the following business day in lieu of the number of copies required pursuant to the applicable statute, rule, or order. If such filing is made electronically on the day of or day before a hearing on the matter, the paper copies shall be provided to the Commission no later than one (1) hour prior to the scheduled start of the hearing. The failure to provide the required number of paper copies within the prescribed timeframe may result in the electronic filing being rejected and excluded from the record in that proceeding.

(1) For all Class A and B electric, telephone, natural gas, water, and sewer utilities, applications for or filings of a general increase in rates, fares, or charges for revenue purposes or to increase the rate of return on investment or to change transportation rates, fares, etc. pursuant to Rule R1-17, and all testimony and exhibits of expert witnesses filed by any party to the general rate case proceeding.

(2) For all Class A and B electric utilities, applications for changes in rates in annual rate rider proceedings pursuant to G.S. 62-133.2, 62-133.8, and 62-133.9, and Rules R8-55, R8-67, and R8-69, and all testimony and exhibits of expert witnesses filed by any party to such proceeding.

(3) For all Class A and B natural gas utilities, applications for changes in rates in annual prudency review proceedings pursuant to G.S. 62-133.4 and Rule R1-17(k), and all testimony and exhibits of expert witnesses filed by any party to such proceeding.

(4) Other documents, such as testimony and exhibits of expert witnesses, as ordered in specific proceedings.

(f) Fingerprint cards and criminal history record release forms required to be filed by applicants for certificates of exemption to transport household goods pursuant to G.S. 62-273.1 and Rule R2-8.1 may not be filed electronically, but must be filed on paper pursuant to Section (a).

(g) Reports on performance results required to be filed by local exchange telephone companies and competing local providers pursuant to Rule R9-8(d) may be filed electronically, provided that an electronic copy in Excel is also provided to the Public Staff. The electronic copy in Excel may be emailed to the Public Staff at communications@psncuc.nc.gov.

(h) Both paper and electronic filings must be received by the Commission by 5:00 p.m. Eastern time to be considered to be filed on that business day. A filing may be made electronically at any time, but filings submitted after 5:00 p.m. Eastern time are considered to be filed on the next business day. A filing that does not comply with all applicable statutes, rules, or orders may be rejected, unless the filing is accompanied by a motion requesting a waiver of the applicable requirement of a rule or order and the motion is granted. If a filing is rejected, the document is deemed not to have been filed with the Commission. A filing that requires a filing fee is not considered to be filed until the fee has been submitted to the Commission.

DOCKET NO. M-100, SUB 148

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
The Federal Tax Cuts and Jobs Act	)	ORDER ADDRESSING THE
	)	IMPACTS OF THE FEDERAL
	)	TAX CUTS AND JOBS ACT
	)	ON PUBLIC UTILITIES

BY THE COMMISSION: On December 22, 2017, President Donald J. Trump signed into law the Tax Cuts and Jobs Act (the Federal Tax Cuts and Jobs Act or the Tax Act). Among other provisions that are contained in this tax reform are provisions that will upon implementation reduce the tax rate of most, if not all, investor-owned public utilities providing services in North Carolina. Specifically, the new federal legislation reduces the federal corporate income tax rate from 35% to 21%, effective for taxable years beginning after December 31, 2017. This reduced tax rate when effectuated will have an immediate and favorable impact on the cost of providing the aforementioned public utility services to consumers in North Carolina.

On January 3, 2018, the Commission issued an Order Ruling That Certain Components of Certain Public Utility Rates Are Provisional as of January 1, 2018, Initiating a Generic Proceeding, and Requesting Comments in response to the Federal Tax Cuts and Jobs Act (the Order). The Order concluded that each and every public utility subject to the provisions of the Order were placed on notice that the federal corporate income tax expense component of all existing rates and charges, effective January 1, 2018, would be billed and collected on a provisional rate basis pending further investigation and disposition of this matter by the Commission, with accompanying deferred accounting for the amount of reduced rates. The Commission further specifically found it appropriate to exclude any water and/or wastewater public utility with $250,000 or less in annual operating revenues from the directives of the Order.

In addition, the Commission requested comments and reply comments in regard to how the Commission should proceed in response to the enactment of the Federal Tax Cuts and Jobs Act. Also in the Order, the following companies were specifically requested to file initial comments: Duke Energy Carolinas, LLC (DEC); Duke Energy Progress, Inc. (DEP); Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (DENC); Piedmont Natural Gas Company, Inc. (Piedmont); Public Service Company of North Carolina, Inc. d/b/a PSNC Energy (PSNC); Frontier Natural Gas Company, LLC (Frontier); Toccoa Natural Gas (Toccoa); Aqua North Carolina, Inc. (Aqua); and Utilities, Inc. (hereinafter collectively referred to as the Utilities). Additionally, the North Carolina Utilities Commission - Public Staff (Public Staff) was requested to file initial comments, and other interested parties were encouraged to file comments.

The Commission requested that the Utilities include the following information in their initial comments:

(1) the estimated annual cost-of-service effect, on an item-by-item basis, of the changes to the levels of income tax expenses expected due to the enactment of the Federal Tax Cuts and Jobs Act. Please show the amount of each change and the related levels of tax expense before and after each change. Such information is to be presented on an NCUC jurisdictional basis (e.g., on a NC retail or NC intrastate basis, as appropriate); and

(2) a complete detailed narrative explanation of how the Utility proposes to account for and treat excess deferred income taxes that were accrued in earlier years under federal corporate income tax rates that were in excess of those set forth in the Federal Tax Cuts and Jobs Act.

The following parties filed a timely petition to intervene in this docket, and, by Order, the Commission granted each petition to intervene: Cardinal Pipeline Company, LLC (Cardinal), the Carolina Industrial Groups for Fair Utility Rates (CIGFUR), the Carolina Utility Customers Association, Inc. (CUCA) (along with its initial comments), the North Carolina Justice Center and the North Carolina Housing Coalition (jointly the Low-Income Advocates), and the North Carolina Sustainable Energy Association (NCSEA).

On January 12, 2018, the Attorney General filed its Notice of Intervention pursuant to N.C. Gen. Stat. § 62-20.

Toccoa filed its initial comments on January 24, 2018. On February 1, 2018, the following parties filed initial comments: the Attorney General, Aqua, Carolina Water Service, Inc. of North Carolina (CWSNC), CIGFUR, DEC and DEP (jointly, DEC/DEP), DENC, Frontier, the Low-Income Advocates, Piedmont, PSNC, and the Public Staff.

On February 9, 2018, Nucor Steel-Hertford (Nucor) filed a Petition to Intervene Out-of-Time.

On February 13, 2018, the Attorney General filed a Motion for Extension of Time to File Reply Comments. In its Motion, the Attorney General requested an extension of time for all parties to file reply comments by no later than February 20, 2018.

By Order dated February 14, 2018, the Commission granted the Attorney General's Motion for Extension of Time to File Reply Comments.

On February 16, 2018, the Commission issued an Order Allowing Petition to Intervene Out-of-Time for Nucor.

On February 20, 2018, the Attorney General, CIGFUR, DEC/DEP, DENC, the Low-Income Advocates, Nucor, Piedmont, and the Public Staff filed reply comments.

On February 28, 2018, the Public Staff filed its Clarification to Reply Comments.

On March 1, 2018, DEC/DEP filed Supplemental Comments taking into consideration the Commission's February 23, 2018 DEP rate case order and the reply comments of the parties.

On March 2, 2018, the Public Staff filed a letter concerning DEC/DEP's March 1, 2018 Supplemental Comments.

On March 27, 2018, DEP filed Supplemental Comments.

On April 3, 2018, the Public Staff filed a letter to address DEP's March 27, 2018 Supplemental Comments.

On April 6, 2018, CWSNC filed a Procedural Request Regarding Implementation of the Federal Tax Cuts and Jobs Act in this generic docket and Docket No. W-354, Sub 360.

On June 22, 2018, the Commission issued its Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction in DEC's rate case proceeding (Docket No. E-7, Sub 1146) wherein the Commission addressed most of the impacts of the Tax Act on DEC.

INITIAL COMMENTS

Electric Utilities

DEC/DEP maintained that it is the Companies' intent that customers will receive the benefits of tax reform. DEC/DEP stated that they propose to accomplish this with solutions that will lower customer bills in the near-term, help mitigate volatility due to future rate increases, and protect the Companies' current credit quality for the benefit of customers. DEC/DEP asserted that they have worked diligently and successfully over the years to serve their customers while maintaining strong balance sheets to support and fund their obligations. DEC/DEP opined that a solid financial foundation has helped the Companies keep customers' rates significantly below the national average for many decades, all while providing safe, reliable and increasingly clean energy for North Carolina.

DEC/DEP asserted that electric utilities are one of the most capital intensive industries in the country and that, in part, is why utilities are heavily regulated. DEC/DEP noted that the Companies invest in infrastructure not because of federal tax policy, but because it is critical, necessary and often legally required that they do so. DEC/DEP stated that their statutory obligation to serve requires the financial wherewithal to support the commitments to their customers on a reliable and cost-effective basis at all times. DEC/DEP maintained that credit quality drives access to affordable capital, and for this reason it is in the best interest of customers to prevent a weakening of the Companies' cash flows and credit quality from pre-Tax Act levels. DEC/DEP stated that as they continue to modernize the energy grid, avoid and reduce outages through new technology, help customers become even more energy efficient through the deployment of advanced metering and technology infrastructure, increase the ability of the grid to connect more distributed and renewable energy resources, and overall transform the customer experience, the need to maintain much-needed cash flow and a strong balance sheet are more important than ever.

DEC/DEP stated that recent federal tax reform provides the Commission with a unique opportunity to help reduce and smooth out volatility in customer rates over the short- and long-term, while maintaining the Companies' pre-Tax Act credit quality and the ability to provide safe, reliable and affordable energy. DEC/DEP asserted that the Commission has substantial discretion in its ratemaking treatment of these tax changes and specifically noted the North Carolina Supreme Court decision in State ex rel. Utilities Comm'n v. Nantahala Power and Light Co., 326 N.C. 190, 388 S.E.2d 118 (1990) (herein after the Nantahala case). DEC/DEP noted that the Supreme Court in that case held that the Commission had the authority to address tax reform through a rulemaking proceeding, rather than only through a general rate case proceeding and that such action did not constitute single-issue ratemaking because there were no adjudicative-type facts in dispute that would require individual hearings. DEC/DEP maintained that the Nantahala case supports the ability of the Commission to determine how to address changes resulting from federal tax reform, but does not mandate that the Commission address such impacts in any particular manner. DEC/DEP stated that, as such, the Commission has the authority to grant the Companies' proposed treatment of the federal tax reform changes. DEC/DEP asserted that adjusting utility rates solely to account for the impact of the reduction in the federal corporate income tax rate and the flow back of excess deferred income tax (EDIT) is not appropriate. DEC/DEP stated that the Commission should also take into account all other impacts of the Tax Act as well as other non-tax inputs that could affect rates. DEC/DEP maintained that the Tax Act represents a unique opportunity to deliver savings to customers, but as with all ratemaking actions, the interests of customers and the Companies should be balanced.

DEC/DEP noted that the headline change to the corporate tax code is a reduction of the statutory federal corporate income tax rate from 35% to 21%. DEC/DEP stated that this reduction in the federal corporate income tax rate, however, is accompanied by many other provisions that serve to broaden the tax base and to "pay for" the effect of the 21% tax rate. DEC/DEP noted that most of the provisions of the Tax Act take effect beginning January 1, 2018.

DEC/DEP maintained that most changes to the corporate tax code apply to all U.S. corporations equally, while a limited set of others affect regulated utilities uniquely. DEC/DEP noted that for utilities in general, and the Companies in particular, the key provisions of the Tax Act that will affect customer rates are as follows: (1) reduction in the federal corporate income tax rate from 35% to 21%; (2) retention of net interest expense deductibility; (3) elimination of bonus depreciation; (4) elimination of the manufacturing deduction; and (5) normalization of EDIT resulting from the Tax Act.

DEC/DEP stated that the Tax Act makes five principal changes to the tax code that affect regulated electric utilities, as follows:

(1) Reduction in Federal Corporate Income Tax Rate

DEC/DEP noted that the new statutory federal corporate income tax rate of 21% represents a 40% reduction from the previous rate of 35%. DEC/DEP stated that this will lower a key component of cost of service, i.e., income taxes. DEC/DEP stated that in contrast to this lower cost of service impact, however, rate base will be higher in future rate proceedings due to the elimination of bonus depreciation and the reduced value of accelerated depreciation due to the lower federal corporate income tax rate.

(2) Interest Expense Deductibility

DEC/DEP stated that the Tax Act generally provides that net interest expense is deductible only to the extent it does not exceed a stated percentage of an adjusted taxable income calculation, a calculation that becomes even more restrictive four years hence. DEC/DEP maintained, however, that regulated utilities are exempt from this limitation provision and may deduct their interest expense without limitation. DEC/DEP stated that Duke Energy and Edison Electric Institute (EEI) (a regulated electric utility trade association) fought hard to achieve this important exemption, and the Companies' customers will retain the significant benefits that flow from it.

(3) Depreciation and Expensing of Capital

DEC/DEP maintained that the Tax Act generally provides that corporations may immediately expense capital as it is placed in service, akin to 100% bonus depreciation. However, DEC/DEP noted, the Tax Act specifically prohibits the immediate expensing of capital by regulated utilities. DEC/DEP stated that, instead, utilities are directed to use modified accelerated cost recovery system (MACRS) depreciation for capital investment placed in service. DEC/DEP asserted that though no longer accompanied by "bonus" depreciation, MACRS still represents a significantly accelerated rate of depreciation compared to book depreciation. DEC/DEP noted that, as a result, deferred taxes will continue to accrue under MACRS, but will do so at a slower rate compared to bonus depreciation and at a much slower rate under the lower 21% federal corporate income tax rate and this will cause a more rapid increase to rate base relative to pre-Tax Act.

(4) Manufacturing Deduction

DEC/DEP stated that prior to the Tax Act, domestic manufacturers were granted a tax deduction based on a certain percentage of qualifying manufacturing income, and the production of electricity qualified for this tax benefit. DEC/DEP noted that in order to avail itself of this deduction, a corporation had to be in a taxable income position and this was often not the case recently for most regulated utilities because of the impact of bonus depreciation. DEC/DEP maintained that, unfortunately, the elimination of bonus depreciation for utilities in the Tax Act coincided with the elimination of this tax deduction for all manufacturers, which is directionally detrimental to customer rates.

(5) Excess Deferred Income Taxes

DEC/DEP noted that at the end of 2017, the Companies had a significant net deferred tax liability, booked at a 35% federal corporate income tax rate and driven overwhelmingly by accelerated and bonus depreciation of fixed assets for tax purposes. DEC/DEP maintained that because a deferred tax liability represents taxes collected from customers, but not yet paid to taxing authorities, and because the ultimate payment of these taxes will now occur at a 21% corporate income tax rate, down from 35%, the balance of the deferred tax liability must be re-measured. DEC/DEP stated that this resulting "excess" deferred tax balance becomes a regulatory liability. DEC/DEP asserted that the Tax Act requires that excess deferred taxes generally associated with property, and specifically connected to the accelerated depreciation of property, must be normalized into customers' rates in a highly-prescribed manner that mimics the remaining life of the underlying assets. DEC/DEP stated that these are known as "protected" excess deferred taxes. DEC/DEP noted that all other excess deferred taxes (i.e., unprotected EDIT) may be treated by the Commission like any other regulatory liability in the rate-setting process.

DEC/DEP asserted that pursuant to the Commission's January 3, 2018 Order, DEC/DEP will defer (by being booked in FERC Accounts 229 and 254) as a regulatory liability (1) all excess accumulated deferred income tax (ADIT) balances created by the Tax Act, and (2) the estimated difference between customer revenues actually earned and what would have been earned taking into account the reduced corporate income tax rate beginning January 1, 2018, until the Commission determines the timing and nature of such benefits to customers.

DEC/DEP asserted that implementation of the Tax Act has the potential to adversely affect the Companies' cash flows needed to fund ongoing operations and new infrastructure investments, and makes having a strong equity to debt capital structure even more important post-Tax Act reform. DEC/DEP stated that an unmitigated cash flow shortfall could force the Companies to rely excessively on third-party capital to fund DEP and DEC, to the ultimate detriment of their financial condition. DEC/DEP maintained that DEC, for example, is in the midst of a base rate proceeding where the Company has demonstrated that its revenues are already insufficient to provide recovery of its reasonable costs and earn a reasonable return. DEC/DEP argued that adjusting the Companies' rates downward in isolation for just the reduction in the federal corporate income tax rate will make an undesirable situation worse from an overall cash flow perspective. DEC/DEP noted that in petitions to intervene filed in this proceeding, as well as in filings made in the pending DEP and DEC rate cases, some intervenors have called for the Commission to reduce customer rates and the Companies' revenues immediately for 100% of the impacts of the Tax Act. DEC/DEP stated that those intervenors argue for an immediate use of only the benefits under the Tax Act, to the exclusion of other provisions of the Tax Act, in isolation and without regard to the utility's current financial position and other relevant factors. DEC/DEP asserted that in the longer-term, one of the unintended consequences of the Tax Act is that the lower tax rate and the elimination of bonus depreciation will increase the Companies' rate base over time, which has the corresponding effect of increasing customer rates over time. DEC/DEP stated that they respectfully assert that implementing such an approach offered by other intervenors would be unsound policy and would be detrimental to customers over the longer-term.

DEC/DEP maintained that stand-alone utility and consolidated financing structures are based on pre-Tax Act capital flows and were formed to support significant investments to benefit customers. DEC/DEP noted that if incoming cash flows decrease pursuant to tax reform, credit metrics will weaken and financial pressure will increase. DEC/DEP asserted that in a tangible sign of this risk, on January 19, 2018, Moody's changed Duke Energy Corporation's rating outlook from stable to negative in response to the financial impacts of the Tax Act and regulatory uncertainties related thereto. DEC/DEP further noted that Moody's changed the ratings outlook of Piedmont Natural Gas, Inc. and 22 other utilities and utility holding companies from stable to negative.

DEC/DEP attached as Exhibits 1 and 2 to their comments the estimated effect of the Tax Act on DEP's and DEC's cost of service. DEC/DEP stated that these estimates are based on the cost of service studies from Docket Nos. E-7, Sub 1026 and E-2, Sub 1023, respectively, which are the rate cases in which current rates were established. DEC/DEP noted that these exhibits also show a resulting reduction in the annual revenue requirement of $104 million for DEP and $172 million for DEC, and translate that into a decrement rate per kilowatt hour, based on the kilowatt hours in those cases.

DEC/DEP further noted that based on the DEP NC 2013 rate case, the total tax expense savings is $104 million. DEC/DEP maintained that the Company (DEP) will not know the level of tax expense savings based on the pending rate case until the Commission order is received. DEC/DEP noted that the difference between the actual amount of tax expense savings based on the rates set in Docket No. E-2, Sub 1142 and the $104 million would be deferred into a regulatory liability account for consideration in a future proceeding. DEC/DEP stated that based on the DEC NC 2013 rate case, the total tax expense savings is $172 million. DEC/DEP stated that the Company (DEC) will not know the level of tax expense savings based on the pending rate case until the Commission order is received. DEC/DEP maintained that the difference between the actual amount of tax expense savings based on the rates set in Docket No. E-7, Sub 1146 and the $172 million would be deferred into a regulatory liability account for consideration in a future proceeding.

DEC stated that it would propose to continue this deferral until new rates can be established in its currently pending rate case in Docket No. E-7, Sub 1146 that reflect the benefits of the lower tax expense. DEP noted that it would propose to continue this deferral until an order is issued by the Commission in its currently pending rate case in Docket No. E-2, Sub 1142. DEP stated that at that time, it will recalculate the cost of service impacts of the Tax Act based on the compliance cost of service, and start deferring based on the updated decrement rate per kilowatt hour. DEC/DEP stated that should the Commission establish a rider for DEP to reflect the benefit, DEP would stop the deferral when the rider was effective.

DEC/DEP maintained that the attached exhibits only show the impact of the Tax Act on base rates. DEC/DEP stated that they expect there may be additional benefits for customers through reduced rider rates, which will be handled in the respective annual rider filings and experience modification factors.

DEC/DEP stated that they propose to pass on savings from the income tax expense reduction to customers. DEC/DEP maintained that in passing on the tax expense savings to customers, the Commission has and should use its ability to implement the Tax Act changes in a way that provides customers with near-term benefits, while minimizing customer rate volatility over both the shorter and longer-term. DEC/DEP noted that with two pending rate cases before it, the Commission has the unique opportunity to help mitigate rate increases by applying the federal income tax expense savings to offset a portion of the requested increases. DEC/DEP asserted that this could be accomplished by offsetting items such as storm response costs, ongoing coal ash basin closure compliance costs or other environmental compliance costs, or accelerating the depreciation of certain assets such as the existing AMR meters or coal plants. DEC/DEP stated that the use of accelerated depreciation would benefit customers by lessening future rate increases caused by rate base growth resulting from the Tax Act.

DEC/DEP proposed to hold the EDITs to be addressed in future rate cases for the benefit of customers. DEC/DEP stated that, specifically, for excess deferred income taxes, the Companies propose to establish regulatory liabilities. DEC/DEP noted that similar to the liabilities created as a result of North Carolina House Bill 998's State corporate income tax rate changes and in compliance with Docket No. M-100, Sub 138, the amortization of these liabilities should be addressed in the Companies' next general rate proceedings. DEC/DEP further stated that it is important to note that a significant portion of the EDIT resulting from the Tax Act will be subject to Internal Revenue Service (IRS) normalization restrictions.

DEC/DEP noted that with respect to DEC, the Company proposes to address federal tax reform impacts in its pending rate case in Docket No. E-7, Sub 1146, for which the evidentiary hearing is currently scheduled to begin on February 27, 2018[1]. DEC/DEP noted that with respect to DEP, the Company also has a pending rate case in Docket No. E-2, Sub 1142; however the record in that case has been closed, and DEP anticipated that the Commission would issue a final order in the near term[2]. DEC/DEP stated that once the Commission order in that rate case proceeding is received, DEP will be able to calculate the impacts of the Tax Act on tax expense based on a compliance cost of service with the Commission's order. DEP proposed to defer the resulting estimated impacts to a regulatory liability, until DEP's next rate case. DEC/DEP maintained that as an alternative, the Commission could approve a rider in Docket No. M-100, Sub 148 to reduce DEP customer rates including any potential offsets.

DEC/DEP requested that the Commission approve and adopt the recommendations contained in their initial comments, enabling the Companies to provide benefits to customers and continue building the energy future their customers and communities deserve.

DENC noted that among other modifications to the Internal Revenue Code, such as repealing the deduction for income attributable to domestic production activities and modifying the cost recovery rules for property, the Tax Act reduces the federal corporate income tax rate from 35% to 21%, effective for taxable years beginning after December 31, 2017.

DENC provided as Attachment 1 to its initial comments the impact of the Tax Act on DENC's base non-fuel cost of service, addressing: (1) the reduction of the federal corporate income tax rate from 35% to 21%, and (2) the repeal of the Section 199 Domestic Production Activities Deduction. DENC noted that Section 13305 of the Tax Act repeals the Section 199

[1] The evidentiary hearing was subsequently changed to begin on March 5, 2018. The Commission issued its Order in DEC's rate case proceeding on June 22, 2018.

[2] The Commission issued its Order in DEP's rate case proceeding on February 23, 2018.

Domestic Production Activities Deduction; removing this federal tax deduction increases income tax expense by $0.7 million. DENC maintained that overall, annual North Carolina jurisdictional income tax expense is expected to decrease by approximately $10.8 million with a corresponding increase to operating income of the same amount beginning January 1, 2018.

DENC also noted that it reduced the balance of ADIT in its financial records to reflect an estimated amount of EDIT for the Virginia Electric and Power Company system effective December 31, 2017. DENC stated that, however, such estimate and the portion allocable to the North Carolina retail operations will be further refined throughout the coming year as a more detailed analysis is completed and needed guidance from the IRS is forthcoming.

DENC further stated that in addition to the Company's base non-fuel rate cost of service, the Tax Act impacts the Company's Rider EDIT, as approved in the Company's 2016 Base Rate Case Order. DENC noted that Rider EDIT is a decrement rider that refunds to customers over a two-year period, commencing on November 1, 2016 through October 31, 2018, a regulatory liability for EDIT associated with recent reductions in the North Carolina corporate income tax rate. DENC noted that the regulatory liability approved by the Commission was calculated using a tax gross-up factor that included a 35% federal income tax rate in effect prior to the enactment of the Tax Act. DENC maintained that beginning January 1, 2018, the federal corporate income tax component of the tax gross-up factor will be reduced from 35% to 21% pursuant to the Tax Act. DENC provided as Attachment 1 to its initial comments a schedule showing the reduction in the regulatory liability and the associated reduction to the Rider EDIT credit of $1.4 million for the period January 1, 2018 through October 31, 2018 due to the change in the tax gross-up factor.

DENC asserted that in accordance with Generally Accepted Accounting Principles (GAAP), the Company recorded in its financial records a reduction in the balance of EDIT effective December 31, 2017, to reflect an estimate of the impact of the Tax Act. DENC stated that the reductions in ADIT associated with the Company's regulated operations and recognized for ratemaking purposes were reclassified to regulatory liability accounts. DENC noted that the predominant amounts of EDIT established as a regulatory liability are associated with utility property depreciation and related book-tax timing differences that are subject to the Internal Revenue Code's normalization rules pursuant to new Internal Revenue Code (IRC) Section 1561(d) that contains similar provisions to the rules promulgated in Section 203(e) of the Tax Reform Act of 1986. DENC maintained that pursuant to Section 13001 of the Tax Act, the Company is required to use the average rate assumption method (ARAM) for purposes of amortizing EDIT over the remaining regulatory lives of the property that gave rise to the original reserve for deferred taxes. DENC stated that amortizing such EDIT using a methodology other than ARAM would violate the normalization rules and would result in the loss of the use of accelerated depreciation by the Company and a cash penalty equal to the amount by which the excess deferred tax reserve is reduced more rapidly than permitted under the Tax Act. DENC asserted that, accordingly, the Company will begin amortizing the estimated plant-related EDIT for financial accounting purposes effective January 1, 2018 subject to adjustment pending additional guidance from the IRS.

DENC further noted that as directed by the Commission in the Order, DENC is now treating the federal corporate income tax component of its existing approved rates and charges as provisional rates that are subject to deferral accounting. DENC stated that this includes the Company's currently-approved and effective base rates (fuel and non-fuel), as well as: (i) annual riders for fuel and fuel-related costs, the Company's demand-side management programs and energy efficiency program costs (DSM/EE), and Renewable Energy and Energy Efficiency Portfolio Standard (REPS) compliance costs, and (ii) Rider EDIT.

DENC maintained that for purposes of the Company's base non-fuel rates and Rider EDIT, the Company intends to address the cost of service impacts and disposition of deferred amounts due to the Tax Act through the Commission's general ratemaking procedure set forth in N.C. Gen. Stat. § 62-130 and N.C. Gen. Stat. § 62-133. DENC stated that this approach ensures that the Company has sufficient time to comprehensively evaluate the direct and indirect impacts of this complex new tax legislation in determining the Company's updated cost of service. DENC asserted that the differences between rates in effect at January 1, 2018, including provisional components, and revenues that would have been billed incorporating the IRC as now amended by the Tax Act, will be held in a deferred account. DENC argued that this approach is reasonable and fair to customers and the Company, as the Company is now collecting these amounts on a provisional basis. DENC stated that through the Company's next general rate case, DENC will comprehensively address all impacts from the Tax Act as part of its updated cost of service filed in that proceeding. DENC maintained that North Carolina's general ratemaking procedures provide the most reasonable and appropriate mechanism to assess the ongoing justness and reasonableness of the Company's rates, and to affect future rate changes in a manner that ensures both customers and the utility are treated fairly based upon a comprehensive review of increases or decreases in the Company's total cost of service.

DENC further stated that for the Company's rates and charges with approved deferral accounting and experience modification factors (i.e., fuel factor, DSM/EE, and REPS riders), the Company proposes to defer any differences between rates in effect at January 1, 2018, including any provisional components, and revenues that would have been billed incorporating the IRC as now amended by the Tax Act, through the ordinary deferral accounting process. DENC noted that any such differences will be addressed in future annual rider proceedings where applicable.

Natural Gas Utilities

Frontier noted that it is in a unique situation with regard to the provision of natural gas sales and distribution service in North Carolina at rates approved by the Commission. Frontier stated that when it was established and granted the necessary certification to serve customers in Ashe, Surry, Watauga, Wilkes, Yadkin, and Warren counties, the initial rates established were not based on a cost of service. Frontier maintained that at the time initial rates were approved for Frontier, the Company had not installed the necessary distribution system to attach customers, but needed to have rates established that were competitive with other available fuels. Frontier commented that as the Commission noted in Docket No. G-38, Sub 1, "[i]t is more accurate to describe the rates to be established in this proceeding as initial franchise rates, recognizing that they are based upon estimates of construction costs, expenses, revenues, and financing costs and upon a determination that they are competitive with alternative fuels." (Order Awarding Certificate and Approving Rates for Warren County, Docket No. G-38, Sub 1, at p.10 (March 27, 1997)).

Frontier stated that pursuant to numerous intervening Commission orders and settlements, Frontier continues to operate under the same initial franchise rates with the exception of the Gross Receipts Tax removed from margin rates and recovered through a surcharge which kept the Company whole in 1999, and a reduction in residential and small commercial rates as agreed to in a stipulation when Frontier was acquired by Energy West Inc. in 2007. Frontier noted that it has never undergone a general rate case proceeding under N.C. Gen. Stat. § 62-133 and has never had the Commission determine cost-of-service based rates for the services it provides. Frontier asserted that there has been no rate case where investment, expense, capital structure, return on equity, among other rate case items, have been considered or acted on by the Commission.

Frontier noted that in the Commission's 2013 proceeding addressing the decrease in the State corporate income tax rate (Docket No. M-100, Sub 138), the Public Staff acknowledged that Frontier provides gas service pursuant to rates established in connection with the granting of its certificate, not rates established in a general rate case based on specific items of cost. Frontier also noted that, therefore, the Public Staff recommended that the Commission not adjust Frontier's rates as a result of HB 998 (the State legislation decreasing the State corporate income tax rate). Frontier maintained that the Commission agreed with the Public Staff and found it appropriate to exclude Frontier from further consideration by the Commission in that docket. Frontier stated that the Commission's ruling effectively exempted Frontier from any obligation to flow-through the State corporate income tax reductions adopted in HB 998 on the grounds that its rates were not cost-based in the first instance; therefore, it made little sense to compel the adoption of a cost-based adjustment to those rates. Frontier argued that the same logic would compel a similar result in this docket.

In response to the two questions posed by the Commission in its January 3, 2018 Order, Frontier noted that in the absence of a prior Frontier rate case, there is no specific rate case detail to base a response on. Frontier requested that it be allowed to continue charging its existing rates that have been in effect with minimal changes for 20 years. Frontier further noted that the excess deferred income taxes will be treated in a manner specified by the IRS rules and regulations; specifically, Frontier will amortize the excess over the remaining life of the assets.

Piedmont stated that it intends to pass the benefits of tax reform back to all customers served pursuant to Piedmont's Commission-approved rate schedules. Piedmont maintained that it proposes to effectuate that intent through solutions that will lower customer bills in the near-term, help mitigate volatility due to future rate increases, and protect the Company's current credit quality for the benefit of customers. Piedmont asserted that it has worked diligently and successfully over the years to provide high-quality service to its customers while maintaining a strong balance sheet in order to support and fund its ongoing operations. Piedmont stated that a solid financial foundation has helped the Company keep customer rates for natural gas service at reasonable levels while providing safe, reliable and environmentally friendly energy for the State of North Carolina. Piedmont maintained that the Commission has played a critical role in Piedmont's ability to achieve these goals.

Piedmont asserted that natural gas utilities are a very capital intensive operation, which is part of the reason why they are structured as regulated monopolies. Piedmont stated that it makes capital investments in new infrastructure because those investments are necessary to provide critical energy services to the State and to ensure that its natural gas transmission and distribution systems continue to maintain the highest level of safety, not because of federal tax policy. Piedmont argued that its obligation to serve the public requires that Piedmont maintain the financial wherewithal to support such service at all times. Piedmont asserted that some aspects of the Tax Act will disrupt Piedmont's cash flows and have negatively impacted its credit ratings. Piedmont stated that inasmuch as credit quality drives access to affordable capital, it is important, and in the best interest of customers, to prevent a weakening of the Company's cash flow and reverse the degradation of its credit quality.

Piedmont maintained that recent federal tax reform provides both Piedmont and the Commission with an opportunity to reduce customer rates and smooth rate volatility over both the short- and long-term while also preserving Piedmont's ability to provide safe, reliable and affordable energy without endangering its credit quality. Piedmont asserted that the Commission has substantial discretion in its ratemaking treatment of these tax changes. Piedmont argued that adjusting utility rates solely to account for the impact of the reduction in the federal corporate income tax rate and the flow back of EDIT should not be automatic, rather the Commission should consider all matters that could affect rates. Piedmont stated that the Tax Act represents a unique opportunity to deliver savings to customers, but as with all ratemaking actions, the long-term and short-term interests of customers must be balanced.

Piedmont stated that it is proposing to reduce customer bills through the flow-through of tax rate reductions under its Integrity Management Rider (IMR) mechanism while deferring tax rate reductions on its base rates until the next general rate case proceeding where such deferral can be amortized and used to offset any requested base rate increase in that docket. Piedmont maintained that for EDIT, the Company will establish a regulatory liability and, similar to the Commission's treatment of EDIT in Docket No. M-100, Sub 138, would propose that those liabilities be addressed in the Company's next general rate case proceeding. Piedmont also noted that a significant portion of the EDIT resulting from the federal income tax rate change will be subject to normalization restrictions.

Piedmont asserted that, if approved, its proposal will provide customers with the benefit of savings under the Tax Act through rate reductions commencing with its upcoming June 1, 2018 IMR rate adjustment and minimization of rate volatility over both the short- and long-term, while sparing Piedmont, and ultimately customers, from the undesirable impacts of the Tax Act on Piedmont's cash flows and credit quality. Piedmont asserted that its proposal, which represents a balanced approach that benefits customers while minimizing any weakening of credit quality, should be approved by the Commission.

Piedmont maintained that the headline change to the federal corporate tax code is a reduction of the statutory federal corporate income tax rate from 35% to 21%, but this reduction in the tax rate is accompanied by many other provisions that serve to broaden the tax base and to "pay for" the effect of the 21% tax rate. Piedmont noted that most provisions of the Tax Act take effect beginning January 1, 2018.

Piedmont stated that most changes to the corporate tax code apply to all U.S. corporations equally, while a limited set of others affect regulated utilities uniquely. Piedmont maintained that for utilities in general, and Piedmont in particular, the key provisions of the Tax Act that will affect customer rates are as follows: (1) reduction in the federal corporate income tax rate from 35% to 21%; (2) retention of net interest expense deductibility; (3) elimination of bonus depreciation; and (4) normalization of EDIT resulting from the Tax Act.

Piedmont asserted that the purpose of the Tax Act was to stimulate business investments, create jobs and grow the economy. Piedmont stated that an expectation that the financial health of Piedmont not be harmed by tax reform is consistent with these policy objectives and serves as a theme of Piedmont's initial comments.

Piedmont highlighted the following four principal changes to the tax code that affect regulated natural gas utilities due to the Tax Act:

(1) Reduction in Federal Corporate Income Tax Rate

Piedmont noted that the new statutory federal corporate income tax rate of 21% represents a 40% reduction from the previous rate of 35%. Piedmont stated that this will lower a key component of cost of service, i.e., income taxes. Piedmont stated that in combination with the elimination of bonus depreciation, a lower corporate income tax rate will slow the accumulation of deferred income taxes and have an increasing effect on rate base, thereby causing an effect that is opposite to the lower cost of service effect.

(2) Interest Expense Deductibility

Piedmont stated that the Tax Act generally provides that net interest expense is deductible only to the extent it does not exceed a stated percentage of an adjusted taxable income calculation, a calculation that becomes even more restrictive four years hence. Piedmont maintained, however, that regulated utilities are exempt from this limitation provision and may deduct their interest expense without limitation.

(3) Depreciation and Expensing of Capital

Piedmont maintained that the Tax Act generally provides that corporations may immediately expense capital as it is placed in service, akin to 100% bonus depreciation. However, Piedmont noted, the Tax Act specifically prohibits the immediate expensing of capital by regulated utilities. Piedmont stated that, instead, utilities are directed to use MACRS depreciation for capital investment placed in service. Piedmont asserted that though no longer accompanied by "bonus" depreciation, MACRS still represents a significantly accelerated rate of depreciation compared to book depreciation. Piedmont noted that, as a result, deferred taxes will continue to accrue under MACRS, but will do so at a slower rate compared to bonus depreciation and at a much slower rate under the lower 21% federal corporate income tax rate and this will cause a more rapid increase to rate base relative to pre-Tax Act.

(4) Excess Deferred Income Taxes

Piedmont noted that at the end of 2017, it had a significant net deferred tax liability, booked at a 35% federal corporate income tax rate and driven overwhelmingly by accelerated and bonus depreciation of fixed assets for tax purposes. Piedmont maintained that because a deferred tax liability represents taxes collected from customers, but not yet paid to taxing authorities, and because the ultimate payment of these taxes will now occur at a 21% corporate income tax rate, down from 35%, the balance of deferred tax liability must be re-measured. Piedmont stated that this resulting "excess" deferred tax balance becomes a regulatory liability. Piedmont asserted that the Tax Act requires that excess deferred taxes generally associated with property, and specifically connected to the accelerated depreciation of property, must be normalized into customers' rates in a highly-prescribed manner that mimics the remaining life of the underlying assets. Piedmont stated that these are known as "protected" excess deferred taxes. Piedmont noted that all other excess deferred taxes may be treated by the Commission like any other regulatory liability in the rate-setting process. Piedmont stated that if all excess deferred tax liability balances are normalized for rate-setting purposes, the impact to Piedmont from a return of the excess ADIT to customers would be neutral to pre-Tax Act cash flow even as customers will realize a rate benefit over time.

Piedmont asserted that pursuant to the Commission's January 3, 2018 Order, Piedmont will defer as a regulatory liability (1) all excess ADIT balances created by the Tax Act, and (2) the estimated difference between customer revenues actually earned and what would have been earned taking into effect the reduced corporate income tax rate beginning January 1, 2018, until the Commission determines the timing and nature of such benefits to customers.

Piedmont maintained that the implementation of the Tax Act has the potential to adversely affect Piedmont's cash flows needed to fund ongoing operations and new infrastructure investments. Piedmont stated that a cash flow shortfall resulting from the immediate flow-through of tax rate reductions and the excess ADITs could force Piedmont to rely, to a much larger extent, on third-party capital to fund its operations to the ultimate detriment of Piedmont's financial condition and the public interest inherent in maintaining low debt costs. Piedmont asserted that evidence of this detrimental impact from the Tax Act has already arrived in the form of a downgrade to the ratings outlook maintained by Moody's Investors Services for Piedmont and other public utilities issued on January 19, 2018. Piedmont noted that it attached a copy of the downgrade notice as Exhibit 1 to its initial comments. Piedmont maintained that these ratings outlook downgrades are driven by the negative cash-flow consequences of a reduction in federal corporate income tax rates in combination with a reduction in tax deferrals resulting from the loss of bonus depreciation. Piedmont stated that Moody's, in its revised ratings outlook, downgraded Piedmont from stable to negative. Piedmont noted that in the discussion of its downgrades, Moody's makes it clear that it expects the downgraded utilities to attempt to manage the negative impacts of the Tax Act through regulatory mechanisms and holds out some hope that ratings outlooks could return to stable for some of the downgraded utilities if effective regulatory relief is granted.

Piedmont noted that in petitions to intervene filed in this proceeding, as well as in filings made in the pending DEP and DEC rate cases, some intervenors have called for the Commission to reduce customer rates and the utilities' revenues immediately for 100% of the impacts of the Tax Act. Piedmont stated that they argue for an immediate pass-through of only the benefits under the Tax Act, to the exclusion of other provisions of the Tax Act, in isolation and without regard to the utility's current financial position and other relevant factors. Piedmont argued that implementing this approach would be unsound policy and would be detrimental to customers over the longer-term.

Piedmont asserted that stand-alone utility and consolidated financing structures are based on pre-tax reform capital flows and were formed to support significant investments to benefit customers. Piedmont argued that an immediate flow back resulting from tax reform would significantly lower Piedmont's cash recovery creating pressure to incur additional debt to fund operations. Piedmont maintained that both of these actions will affect Piedmont's credit metrics and ability to continue to issue debt at the cost embedded in current customer rates. Piedmont stated that customers benefit directly from a strong balance sheet and strong investment grade credit ratings through low cost of capital and strong access to capital during all market conditions. Piedmont noted that this was particularly evident during the recent Great Recession. Piedmont asserted that, conversely, a decrease in incoming cash flows both increases risk and increases debt costs over time. Piedmont maintained that the Commission should consider these very real consequences of the Tax Act when determining how to adopt appropriate regulatory requirements for Piedmont in this circumstance. Piedmont asserted that its proposals avoid these results while still providing a meaningful degree of immediate rate relief to customers and ensuring that customers ultimately receive the full benefit of the Tax Act.

Piedmont provided as Exhibit 2 to its initial comments the estimated effect of the Tax Act on Piedmont's cost of service. Piedmont noted that this amount, $19,822,593, is based on the Commission-approved Stipulation from Piedmont's most recent general rate case filing in Docket No. G-9, Sub 631. Piedmont stated that it would propose to provide customers with the benefits of its reduced cost of service in two ways. First, Piedmont proposed to implement the new reduced federal corporate income tax rate in calculating surcharges due under its IMR mechanism. Piedmont estimated the impact on its most recent IMR rate change to be approximately $6 million. Piedmont stated that, second, it would seek continued deferral of any excess income tax collections resulting from continuing to charge its current base rates until Piedmont's next general rate case that Piedmont anticipates filing in the next 12 to 24 months. Piedmont noted that this deferred liability could then be amortized and used to offset any rate increase sought in that general rate proceeding. Piedmont asserted that this deferral should not have a carrying charge or interest component associated with it, consistent with the notion of balancing the positive and negative effects of the Tax Act. Piedmont stated that, as an alternative, the Commission could approve a rider in this proceeding to reduce customer rates. Piedmont noted that it also proposed to defer action to address any return of excess ADIT resulting from the Tax Act until Piedmont's next general rate case which is consistent with the manner in which the Commission has addressed this issue in prior tax cut implementation proceedings. Piedmont asserted that this approach to adjusting for excess deferred income taxes would also have a smoothing effect on rates going forward.

Piedmont maintained that by returning a portion of the benefit of the Tax Act to customers through near-term rate decreases in the IMR mechanism and a portion through an amortized offset to any rate increase request in Piedmont's next general rate case proceeding, Piedmont believes that its proposals will achieve an appropriate balance of passing through the benefits of the Tax Act to customers while protecting Piedmont from the negative effects of an immediate flow-through on its credit metrics and financing structures to the ultimate benefit of its customers.

PSNC noted that in response to the Commission's January 3, 2018 Order, attached as Appendix A to its initial comments is a schedule showing the estimated annual effect to PSNC's cost-of-service, on an item-by-item basis, of the changes to the levels of federal corporate income tax expense expected due to the enactment of the Tax Act. PSNC stated that column (a) sets forth the net operating income for return, rate base, and overall return as determined in PSNC's last general rate case, Docket No. G-5, Sub 565, as adjusted to reflect the reduction in the State corporate income tax rate from 4% to 3% effective January 1, 2017. PSNC noted that column (b) sets forth the decrease in federal income tax expense and the revenue requirement impact of that decrease. PSNC further noted that column (c) sets forth the adjusted net operating income for return and return on rate base prior to reducing rates to reflect the reduction in the federal corporate income tax rate. PSNC stated that column (d) sets forth the decrease in revenue and associated adjustments to cost of service. PSNC maintained that in order to simplify the calculation and due to their immateriality, these amounts do not reflect any resulting impact on the cash working capital component of rate base. PSNC noted that column (e) sets forth PSNC's cost of service adjusted for changes resulting from the Tax Act.

PSNC further stated that the reduction in the federal corporate income tax rate from 35% to 21% will result in EDIT. PSNC stated that it proposes, and requests Commission approval, to record the adjustment to deferred taxes as a regulatory liability which will result in no net change in rate base until amortization of the liability begins. PSNC maintained that in accordance with Financial Accounting Standards Board requirements, the adjustments to deferred taxes will be grossed up to a pre-tax amount when recorded as a regulatory liability. PSNC noted that it proposes that the amortization of the regulatory liability be addressed in PSNC's next general rate case.

In addition, PSNC proposed to adjust its rates by allocating the annual revenue requirement impact of the Tax Act changes to the various rate schedules based on the volumes determined in PSNC's most recent general rate case, Docket No. G-5, Sub 565. PSNC stated that the change in rates applicable to each rate schedule will be used to determine the appropriate level of deferred revenue to record per ordering paragraph two of the January 3, 2018 Order. PSNC asserted that due to the administrative burden of implementing a refund by recalculating previously issued bills, PSNC proposes to refund provisionally collected amounts by moving the balance in the regulatory liability account to the Company's All Customers Deferred Account. PSNC noted that this is the same treatment that PSNC used to refund provisionally collected amounts in Docket No. M-100, Sub 138 (the State corporate income tax rate change generic proceeding).

PSNC noted that Appendix B to its initial comments sets forth the adjustments to rates resulting from the decrease in revenue requirement due to enactment of the Tax Act. PSNC stated that proposed rates are set forth on Appendix C.

PSNC also noted that contemporaneous with filing its initial comments, on February 1, 2018, it submitted its Application to Refund Overcollection in Docket Nos. G-5, Sub 565 and M-100, Sub 138[1]. PSNC stated that as indicated therein, the determination of the revenues being billed and collected on a provisional basis pursuant to this docket will include amounts over collected due to the error in adjusting rates for the decrease in the State corporate income tax rate from 4% to 3%, effective January 1, 2017.

Toccoa noted that it is a municipally-owned natural gas system and that it is therefore not a Sub C business corporation. Toccoa stated that because it is a municipally-owned natural gas system, it is not subject to income or other tax obligations. Toccoa maintained that, therefore, based on information and belief, no tax allowances were included in any determination of Toccoa's revenue requirements when the Commission established its rates.

Toccoa stated that because it is not subject to income tax, there will be no changes to the levels of income tax expenses due to the enactment of the Tax Act. Toccoa maintained that, therefore, no adjustment to Toccoa's existing rates would be necessary or appropriate as a result of the passage of the Tax Act.

Water/Wastewater Utilities

Aqua filed the Affidavit of Shannon V. Becker, the Company's President, as its initial comments. Aqua stated that the Company intends to file a general rate case in early-March 2018[2]. Therefore, Aqua requested that the impact of the Tax Act on the Company's rates be resolved in its soon-to-be-filed general rate case and determined in the Order to be issued by the Commission in that proceeding.

Aqua also noted that it will track and defer any benefit that is recognized as a result of the decrease in the federal corporate income tax rate from 35% to 21% on the currently payable piece of federal income tax included in customer rates. Aqua stated that these changes will be recorded to a regulatory liability for consideration in the Company's upcoming general rate case proceeding. Aqua maintained that the information requested by the Commission in its January 3, 2018 Order will certainly be examined as part of the soon-to-be-filed general rate case application and, therefore, recommended that the Commission deal with the issue entirely in that rate case. Aqua estimated the impact on annual revenues due to the Tax Act to be a reduction of $1.5 million.

Aqua also stated that with respect to the Commission's question on how Aqua intended to treat EDIT, the Company proposed to account for the excess deferred federal income taxes by reducing the deferred taxes ratably over the regulatory life of the underlying property. Aqua explained that this issue is broken down into two components, protected and non-protected. Aqua

[1] On February 8, 2018, PSNC filed a letter providing the final amount to be refunded to PSNC's customers due to incorrectly calculating its base rates to reflect the 3% State corporate income tax rate, effective January 1, 2017. On March 28, 2018, the Public Staff filed a letter containing specific recommendations concerning PSNC's February 1, 2018 and February 8, 2018 filings.

[2] On February 5, 2018, Aqua filed its 30-day notice of intent to file a general rate case in Docket No. W-218, Sub 497. Aqua filed its general rate case application on March 7, 2018.

maintained that the protected items must be accounted for by the average rate assumption method (ARAM) or a straight-line method no faster than ARAM in order to not violate normalization accounting. Aqua stated that it intends to defer the process of amortizing these excess deferred taxes until they are addressed in the upcoming rate case filing. Aqua noted that the non-protected excess deferred federal income taxes will be amortized on a yet-to-be-determined period, but will also be added to the regulated liability for consideration in the upcoming rate case. Aqua stated that this issue can be most logically and efficiently dealt with in the upcoming rate case, given the coincidence of timing of the rate case and the January 1, 2018 reduction in the federal corporate income tax rate from 35% to 21%. Aqua asserted that by utilizing this deferral accounting method, all of the effects of the Tax Act will be appropriately captured for proper consideration in the Company's upcoming rate case.

CWSNC filed the Affidavit of Anthony Gray, the Company's Senior Financial and Regulatory Analyst, as its initial comments. CWSNC stated that it agrees that the Commission should consider the impact of the federal corporate income tax change on the existing rates of utilities such as CWSNC. However, CWSNC stated that it believes that all aspects of the revenue requirement calculation need to be considered in this matter and that the new federal corporate income tax rate should not be considered in isolation when determining the impact upon current utility rates[1].

CWSNC noted that its current utility rates were set based upon rate base and operating expense levels, along with the federal corporate income tax rate of 35%, which were in place at the time of the Company's last rate case in 2017. CWSNC stated that the impact upon utility rates cannot be analyzed by only looking at the impact due to the change in just one component of the Company's revenue requirement. CWSNC stated that if the true impact is going to be analyzed for the change in the federal corporate income tax rate, then all other components of the Company's revenue requirement calculation need to be taken into consideration because it is likely that those other components have changed since the rates were last set by the Commission. CWSNC maintained that, for example, the Tax Act now renders Contributions in Aid of Construction (CIAC) for water and wastewater utilities taxable revenue, eliminating the exemption CIAC previously enjoyed. CWSNC noted that this could offset some of the savings from the reduced federal corporate income tax rate.

CWSNC stated that, nevertheless, it has calculated the annual cost of service changes as directed in the Commission's January 3, 2018 Order as a result of the federal corporate income tax rate change as shown on Exhibit 1 to its initial comments.

CWSNC stated that with respect to EDIT, although exact figures will not be available to the Company for at least 60 days, CWSNC has been collaborating with external tax professionals to assess the impact of the excess ADIT due to the change in the federal corporate income tax rate. CWSNC noted that its proposed accounting treatment of the issue is described in Exhibit 2 attached to its initial comments.

[1] The Commission notes that CWSNC filed a 30-day notice of intent to file a general rate case application on March 23, 2018, in Docket No. W-354, Sub 360. CWSNC filed its general rate case application on April 27, 2018.

CWSNC maintained that it also recommends that the Commission consider the impact of the Tax Act upon CIAC. CWSNC noted that the Tax Act removes the tax exemption for CIAC. CWSNC noted that, thus, effective January 1, 2018, water and wastewater utilities like CWSNC will have to begin paying income taxes on cash and property CIAC they receive. CWSNC stated that this change will negatively affect CWSNC's opportunity to earn a reasonable return on its property used and useful in public service if the Company is not allowed to collect the appropriate tax on the CIAC received. CWSNC stated that it will immediately seek to collect from developers (and others) who transfer property and cash to the Company as CIAC based upon the new treatment under the Tax Act; however, there may be some amounts that are not collected as a result of the timing of the tax reform change. CWSNC noted that it does not believe that collection of this tax resulting from a change in the federal tax law requires any modification to its tariff; however, if the Commission believes state law mandates such a change, CWSNC requested clarification and immediate authorization to collect the taxes in the interim.

Other Parties

The Attorney General stated that it recommends that the Commission exercise its rulemaking authority in this proceeding to order the utilities to flow through these federal tax reductions to consumers as soon as possible in the form of rate decreases.

The Attorney General noted that utility rates have been established by the Commission assuming that the utility pays a 35% federal corporate income tax rate, and that tax rate has changed to 21%, a substantial decrease. The Attorney General maintained that the impact affects investor-owned public utilities, generally, and to the extent that utility rates are not adjusted to reflect the new, lower federal income tax rates, utilities would receive large windfalls.

The Attorney General asserted that the Commission has authority to flow through the effect of tax changes to consumers in the form of rate reductions by ordering appropriate adjustments in a rulemaking proceeding, and did so when federal income tax rates for corporations were decreased from 46% to 34% effective July 1, 1987. (See Nantahala case).

The Attorney General recommended that the Commission order utilities to flow through these federal tax reductions to consumers as soon as possible in the form of rate decreases.

CIGFUR stated that CIGFUR I, II, and III are associations of large industrial retail purchasers of electric power from DENC, DEP, and DEC. CIGFUR noted that because income taxes are a major component of utility revenue requirements, the new federal tax law will have a substantial and material impact on the revenue requirements of DENC, DEP, and DEC and consequently on the ratepayers of these electric utilities.

CIGFUR asserted that the Commission should pass the substantial and material benefits of the new federal tax law on to ratepayers and may properly do so through this rulemaking proceeding. CIGFUR noted that the Commission is charged with setting just and reasonable rates for public utilities under Chapter 62 of the North Carolina General Statutes. CIGFUR stated that while Chapter 62 authorizes the Commission to modify base rates through a general rate case, there are exceptions. CIGFUR maintained that in 1990, the North Carolina Supreme Court affirmed a Commission order changing rates via a rulemaking proceeding under similar circumstances: the substantial decrease to the federal corporate income tax rate as a result of the Tax Reform Act of 1986. CIGFUR noted that the Supreme Court held that the Commission properly ordered affected utilities, through a rulemaking procedure, to lower their rates to reflect savings generated by the Tax Reform Act of 1986 when the final rule applied uniformly to the affected utilities that were similarly situated and (1) the tax reduction affected all utilities uniformly, (2) a large number of utilities were affected, making individual hearings for all inappropriate, and (3) no adjudicative-type facts were in dispute so as to require a trial-type hearing for each individual utility.

CIGFUR maintained that it understands that the impact of the new federal tax law will be substantial and material upon the revenue requirements of DEC, DEP, and DENC and will thus trigger the Commission's authority to pass tax reduction savings onto ratepayers via a rulemaking procedure as contemplated by the Nantahala court decision. CIGFUR asserted that in addition to the Commission's January 3, 2018 Order requiring impacted utilities to place the difference between revenues billed under present rates and the savings afforded by the reduction in the federal corporate income tax rate from 35% to 21% in a deferred account, CIGFUR requested that the Commission: (1) order that all public utilities subject to the docket file information setting forth each company's assessment of the new federal tax law on its North Carolina intrastate operations, including its proposal to adjust rates to reflect the reduction in the corporate income tax effectuated by the new federal tax law as soon as practicable and certainly no later than March 1, 2018; (2) issue an order establishing procedures to implement tariff reductions and refunds related to the corporate income tax savings related to the new federal tax law; (3) order that all affected utilities begin filing quarterly reports, no later than April 30, 2018, reflecting the status of the deferred account which the utilities were required to establish pursuant to ordering paragraph no. 2 of the Commission's January 3, 2018 Order; and (4) order each utility to establish a regulatory liability account to address EDIT resulting from the new federal tax law.

CIGFUR asserted that notwithstanding the Commission's authority to address the tax reduction outside of a general rate case, both DEP and DEC have general rate cases pending before the Commission, Docket Nos. E-2, Sub 1142 and E-7, Sub 1146, respectively. CIGFUR noted that it believes that it would be appropriate for the Commission to address the impacts of the new federal tax law through these general rate case proceedings as doing so is both efficient and will reduce confusion among DEP's and DEC's ratepayers.

CIGFUR stated that while in its late stages, DEP's general rate case remains pending before the Commission[1]. CIGFUR noted that the record is closed, however, CIGFUR asserted that the Commission may properly take judicial notice of the new federal tax law and the 40% reduction in the corporate income tax rate. CIGFUR quoted N.C. Gen. Stat. § 62-65(b) that states, "the Commission may take judicial notice of . . . federal statutes, . . . generally recognized technical and scientific facts within the Commission's specialized knowledge, and such other facts and evidence as may be judicially noticed by justices and judges of the General Court of Justice." CIGFUR also provided a quote from a 1998 court decision, as follows: "[f]urthermore, under Rule 201 of the North Carolina Rules of Evidence, the Commission, sitting as a trial tribunal, may

[1] The Commission issued its Order in DEP's rate case proceeding on February 23, 2018.

judicially notice facts that are 'not subject to reasonable dispute in that [they are] either (1) generally known within the territorial jurisdiction of the trial court or (2) capable of accurate and ready determination by resort to sources whose accuracy cannot reasonably be questioned'." CIGFUR asserted that the Commission may properly take judicial notice in its discretion and at any state in the proceeding. CIGFUR requested that the Commission take judicial notice of the Tax Act in Docket No. E-2, Sub 1142, and, accordingly, order DEP to amend its filing to comport with the new tax law, which should be the basis for final approved rates.

In addition, CIGFUR noted that the evidentiary hearing in DEC's general rate case is fast approaching. CIGFUR stated that requiring DEC to update its application to comport with the Tax Act prior to the start of the evidentiary hearings on February 27, 2018 will provide much-needed transparency and accuracy on a significant component of DEC's revenue requirement.[1]

CIGFUR stated that revised and accurate income tax expense and revenue requirements are critical in informing the Commission's determination of just and reasonable rates for DEP and DEC; if the Commission approves rates based on inflated tax numbers, such rates will be unreasonable and in violation of N.C. Gen. Stat. § 62-131. CIGFUR further asserted that setting base rates based upon incorrect tax rates and then later refunding the excess and resetting rates in a separate proceeding will be an inefficient use of the resources of the Commission, the Public Staff, the utility, and ultimately, the using and consuming public. CIGFUR argued that the pending general rate cases are the most efficient and economic vehicle for effectuating the substantial and material impact of the Tax Act. CIGFUR also stated that addressing the federal corporate income tax reduction through the pending general rate cases will avoid ratepayer confusion, which is of great importance considering the significant public scrutiny that is being afforded to DEP's and DEC's general rate case proceedings.

CIGFUR stated that it believes that the Commission should, as quickly as practicable, pass the substantial and material benefits of the Tax Act onto ratepayers through the most efficient means available, be that through this rulemaking proceeding or through pending general rate cases.

CUCA noted that the Commission has dealt with tax rate changes twice in the past 30 years. CUCA stated that in 1986, the Commission established Docket No. M-100, Sub 113 to address utility rates in light of the 1986 Tax Reform Act. CUCA further noted that in 2013, the Commission opened Docket No. M-100, Sub 138 to address the changes from North Carolina Session Law 2013-316 (House Bill 998), An Act to Simplify the North Carolina Tax Structure and to Reduce Individual and Business Tax Rates.

CUCA maintained that the Commission is vested with the power to change rates absent of a rate case that result from a change in taxation of regulated utilities based on the 1990 Supreme Court decision in State ex rel. Utilities Comm'n v. Nantahala Power and Light Co., 326 N.C. 190, 388 S.E.2d 118 (1990). CUCA noted that it is aware of the Commission's Order of October 9, 2014 in Docket No. M-100, Sub 138, specifically in regard to single-issue ratemaking. CUCA noted that the Commission Order stated, in part, as follows:

[1] The evidentiary hearing was subsequently set to begin on March 5, 2018. The Commission issued its Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction in DEC's rate case proceeding on June 22, 2018.

> However, the ratemaking doctrine against single-issue ratemaking in full force in this state, designed to present changes to utility rates outside general rate cases, should be adhered to except in limited, closely circumscribed situations. The insubstantial and immaterial changes at issue in this docket do not fit within the exception. The limitations should be preserved to prevent single-issue ratemaking in the future when tax rates increase in insubstantial and immaterial ways.

CUCA stated that it has estimated the monetary value of this tax rate change to be approximately $116.9 million annually for DEP and $182.4 million annually for DEC. CUCA maintained that these values translate into rate changes for DEC and DEP of 3.55% and 3.66%, respectively. CUCA noted that it has provided the calculations of the values in Appendix 1 as attached to its initial comments. CUCA stated that it did not estimate the rate changes for DENC, PSNC, Piedmont, or Frontier but that CUCA believes that the rate changes for DENC and the three gas utilities will be in the same percentage range as the above-stated rate changes for DEC and DEP. CUCA asserted that in keeping with the Commission's decision in Docket No. M-100, Sub 138, CUCA argues that the rate changes at issue due to the federal tax changes are both substantial and material and do not entail single-issue ratemaking as previously discussed by the Commission.

CUCA stated that it also recognizes that the Commission has previously addressed the issue of EDIT in Docket No. M-100, Sub 138. CUCA noted that the Commission, in that docket, required the establishment of a regulatory liability account for the EDIT that would be addressed in the next rate case for each of the Companies. CUCA stated that it has estimated the issue of EDIT to be approximately $875 million for DEP and over $1.6 billion for DEC. CUCA stated that it estimated these amounts based upon values found in the FERC Form 1 reports of DEP and DEC allocated to the North Carolina retail consumer and from Form E-1, item 45A of the ongoing DEP and DEC rate cases. CUCA stated that given the fact that DEC and DEP have pending rate cases before the Commission, CUCA requested that the Commission address the issue of EDIT in these ongoing cases.

CUCA requested that the Commission order: (1) the creation of a deferred account to capture all of the changes related to the difference between revenues billed under rates now in effect relative to the attendant cost of service based on the federal income tax component from 35% to 21%; (2) an immediate reduction of rates paid by consumers to account for the change in federal income tax rates from 35% to 21%; (3) the creation of a regulatory liability account for each Company to address the change in EDIT as a result of the recent federal tax rate change; and (4) that the issue of EDIT be addressed in the pending DEC and DEP general rate cases.

The **Low-Income Advocates** asserted that the crucial question before the Commission in this docket is how best to take advantage of the tax cut for the benefit of customers. The Low-Income Advocates maintained that several principles should guide the Commission's determination.

First, the Low-Income Advocates stated that excess revenues due to the reduction in the public utilities' cost of service should not accrue to the Companies' shareholders. The Low-Income

Advocates noted that because a utility is authorized a rate of return from captive retail ratepayers, its shareholders are insulated from the fluctuations of the markets. The Low-Income Advocates stated that allowing utility shareholders to reap the benefits of the tax cut would result in a windfall.

Next, the Low-Income Advocates maintained that the public utilities should not be allowed to keep any excess revenues they collect (or have collected) through existing rates and spend those ratepayer dollars however they want for capital or operating expenses.

The Low-Income Advocates also stated that although the Commission has the authority to reduce rates to account for the impact of the tax cut on the public utilities' cost of service, the Commission should not simply order utilities to reduce their rates to account for the entire impact of the tax cut, or to flow all of the over-collections due to the tax cut to their customers in the form of rebates or decrement riders. The Low-Income Advocates asserted that the reduction in the federal corporate income tax has a material and substantial impact on the public utilities' cost of service; therefore, adjustment of rates in light of the tax cut outside a general rate case would not run afoul of the prohibition on single-issue ratemaking in conflict with the Nantahala case.

In addition, the Low-Income Advocates maintained that the utilities should be required to invest some portion of the tax savings for the residential class in measures that reduce customer bills. For example, the Low-Income Advocates stated, the Commission could require electric and natural gas utilities to invest a portion of the tax savings in energy efficiency programs for low-income customers. The Low-Income Advocates noted that because each dollar invested in energy efficiency yields up to four dollars in cost savings to the utility's system[1], directing a portion of utilities' tax savings to such programs would have a greater "bang for the buck" than simply reducing utility rates. The Low-Income Advocates maintained that, similarly, water utilities could be required to invest in water-conservation programs. The Low-Income Advocates stated that such investments would yield greater bill reductions than a simple rate reduction or rebate.

Finally, the Low-Income Advocates maintained that if rates for residential customers are reduced, the Commission should not simply order an across-the-board reduction in rates and charges for the class. Instead, the Low-Income Advocates argued, the Commission should examine whether it is appropriate to require greater reductions in fixed, monthly charges than in the volumetric rate.

The Low-Income Advocates noted that the information that the Commission has directed the utilities to file in their initial comments regarding the impact of the tax cut on their cost of service will assist the Low-Income Advocates in formulating a proposal for how the tax cut monies should be spent for the benefit of low-income residential customers. The Low-Income Advocates stated that they therefore intend to put forth such a proposal in their reply comments.

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[1] The Low-Income Advocates cited ACEEE, Press Release, New Report Finds Energy Efficiency is America's Cheapest Energy Resource (Mar. 25, 2014), http://aceee.org/press/2014/03/new-report-finds-energy-efficiency-a. "Each dollar invested in electric energy efficiency measures yields $1.24 to $4.00 in total benefits for all customers, which include avoided energy and capacity costs, lower energy costs during peak demand periods like heat waves, avoided costs from building new power lines, and reduced pollution."

The **Public Staff** stated that it believes it is permissible for the Commission to address the effects of the Tax Act through this docket. The Public Staff maintained that the Tax Act will result in a significant reduction in the federal corporate income taxes paid by most, if not all, utilities regulated by the Commission. The Public Staff further noted that this reduction will, in turn, result in a reduction in the cost of providing public utility services to North Carolina customers, which the Public Staff believes is sufficiently substantial and material to justify an exception to the doctrine against single-issue ratemaking.

The Public Staff stated that, at a minimum, the items addressed by the Commission in this docket should include: (1) a reduction in rates to reflect the reduction in the federal corporate income tax rate; (2) the flowback to customers of EDIT; and (3) the effects of changes to the taxability of Contributions in Aid to Construction (CIAC), all of which are results of the Tax Act.

Finally, the Public Staff stated that it anticipates that individual utilities may raise unique issues related to the impacts of the Tax Act. The Public Staff stated that it will address these issues in reply comments.

REPLY COMMENTS

Electric Utilities

DEC/DEP stated that in their initial comments, the Companies identified the amount of reduction in annual revenue requirements related to reduced income tax expense resulting from the Tax Act and presented the Commission with a balanced solution to reflect the benefits of the Tax Act through options that will lower customer bills in the near-term, help mitigate volatility due to future rate increases, and uphold the Companies' pre-Tax Act credit quality for the benefit of customers. DEC/DEP noted that based upon the cost of service studies, from Docket Nos. E-7, Sub 1026 and E-2, Sub 1023, respectively, the Companies estimated reductions in the annual revenue requirement of $104 million for DEP and $172 million for DEC, and translated that into a decrement rate per kilowatt hour, based on the kilowatt hours in those cases. DEC/DEP stated that based on the DEP NC 2013 rate case, the total tax expense savings is $104 million. DEC/DEP noted that DEP will not know the level of tax expense savings based on the pending rate case until the Commission order is received[1]. DEC/DEP noted that the difference between the actual amount of tax expense savings based on the rates set in Docket No. E-2, Sub 1142 and the $104 million would be deferred into a regulatory liability account for consideration in a future proceeding. DEC/DEP further noted that based upon the DEC NC 2013 rate case, the total tax expense savings is $172 million. DEC stated that it will not know the level of tax expense savings based on the pending rate case until the Commission order is received. DEC/DEP noted that the difference between the actual amount of tax expense savings based on the rates set in Docket No. E-7, Sub 1146 and the $172 million would be deferred into a regulatory liability account for consideration in a future proceeding.

DEC/DEP noted that in the current DEC rate case proceeding, DEC proposed to apply the decrement to North Carolina retail services beginning January 1, 2018, and defer the resulting

[1] The Commission issued the DEP rate case Order on February 23, 2018.

amount into a regulatory liability until new rates can be established in its currently pending rate case. DEC/DEP further noted that DEC provided additional detail in its rebuttal testimony of witnesses David Fountain, Stephen DeMay, and Jane McManeus filed on February 6, 2018 in Docket No. E-7, Sub 1146.

DEC/DEP noted that in DEP's rate case proceeding, DEP proposed to apply the decrement to North Carolina retail services beginning January 1, 2018, and defer the resulting amount into a regulatory liability until new rates can be established in its next general rate case, or in the alternative to reduce rates in a rider to be established by the Commission in this generic docket. DEC/DEP proposed options to help mitigate future rate increases by applying the federal income tax expense savings to offset items such as storm response costs, ongoing coal ash basin closure compliance costs or other environmental compliance costs, or accelerating the depreciation of certain assets such as the existing AMR meters or coal plants. DEC/DEP asserted that nothing in the intervenors' initial comments changes the Companies' recommendation that the Commission should implement a balanced solution to ensure that customers receive the benefits of tax reform.

DEC/DEP noted that the Public Staff, the Attorney General's Office, CIGFUR, and the Low-Income Advocates, in their initial comments, all agree with DEP and DEC that customers should receive the benefits of federal tax reform. DEC/DEP stated that to the extent that these intervenors are asking for the Commission to reduce customer rates and the Companies' revenues immediately for 100% of the benefits of the Tax Act, however, they do so without regard to the utilities' current financial position and other relevant factors. DEC/DEP asserted that rate decreases pursuant to federal tax reform will decrease cash flows, which will weaken credit metrics. DEC/DEP argued that the weakened metrics will reduce financial flexibility and could ultimately result in increased financing costs, which, in turn, impact customer bills. DEC/DEP maintained that in a tangible sign of this risk, on January 19, 2018, Moody's changed the rating outlook of Duke Energy Corporation and 23 other utilities and utility holding companies from stable to negative in response to the financial impacts of the Tax Act and regulatory uncertainties related thereto.

DEC/DEP stated that as discussed in their initial comments, one of the consequences of the Tax Act is that the lower tax rate and the elimination of bonus depreciation will increase the Company's rate base over time, which has the corresponding effect of increasing customer rates over time. DEC/DEP maintained that they have proposed that the Commission could mitigate these impacts by offsetting items such as storm response costs, ongoing coal ash basin closure compliance costs or other environmental compliance costs, or accelerating the depreciation of certain assets such as the existing AMR meters or coal plants. DEC/DEP noted that the accelerated depreciation would be accomplished by creating a North Carolina retail regulatory liability. DEC/DEP stated that that liability would then be used to reduce depreciation expense on the specific asset or group of assets the next time depreciation rates are updated, similar to the way that the DEP Harris Nuclear Plant accelerated depreciation was used to reduce depreciation expense in Docket No. E-2, Sub 1023. DEC/DEP asserted that the use of accelerated depreciation would benefit customers by lessening future rate increases caused by rate base growth resulting from the Tax Act. DEC/DEP stated that their proposed response to the federal tax reform, therefore, provides the Commission with an opportunity to help reduce and smooth out volatility in customer rates over the short- and long-term, while maintaining the Companies' pre-Tax Act credit quality for the benefit of customers.

DEC/DEP requested that the Commission approve and adopt their recommendations to deliver savings to customers in a manner that balances the interests of customers and the Companies.

DENC stated that it agrees with the Public Staff and certain other parties that the enactment of the Tax Act has a material impact on the Company's future cost of service and should benefit North Carolina ratepayers through lower utility rates. DENC maintained that given the magnitude of the Tax Act's impact on the Company's future cost of service, DENC recognizes that the Commission may deem it appropriate to expeditiously address the federal corporate income tax changes through a rulemaking procedure under the Public Utilities Act. DENC noted that the 1990 North Carolina Supreme Court Nantahala decision established the Commission's authority under the Public Utilities Act to require single-issue ratemaking adjustment by rulemaking procedure outside of a general ratemaking process to pass through a similarly material reduction in federal corporate income tax rates.

DENC maintained that it recognizes the Public Staff's and other parties' objective of ensuring that provisionally-collected amounts are expeditiously recognized in the Company's utility rates. However, DENC asserted that efficiencies would be achieved by comprehensively addressing all federal income tax issues in the Company's next general rate case. DENC stated that to balance these interests, the Company commits to filing a single-issue adjustment to its base rate cost of service on or before June 30, 2019, if the Company has not filed a general rate case as of that date.

DENC asserted that for the Company's non-base rates and charges with approved deferral accounting and experience modification factors (i.e., fuel factor, riders for the Company's demand-side management programs and energy efficiency program costs, and Renewable Energy and Energy Efficiency Portfolio Standard compliance costs), the Company continues to recommend addressing the impact of the Tax Act in upcoming annual rider proceedings where applicable.

DENC also maintained that with regard to addressing excess deferred federal income taxes associated with the Tax Act's federal corporate income tax rate reduction, the Company also recommends that the Commission address the effect of the EDIT in the Company's next general rate case. DENC argued that this approach will ensure that ratepayers receive the benefit of EDIT created by the Tax Act, while also preserving the Company's ability to deduct accelerated depreciation on its federal income tax returns for the benefit of ratepayers. DENC stated that as explained in the Company's initial comments, the predominant portion of EDIT is subject to the IRC's normalization rules. DENC maintained that certain tax technical issues have yet to be resolved and additional guidance from the IRS is expected. DENC argued that addressing the ratemaking treatment of EDIT in the Company's next general rate case rather than through rulemaking allows for additional time to resolve these issues to ensure that the Company's rates and charges are maintained in accordance with the IRC's normalization rules.

DENC opined that provisional recovery and deferral accounting combined with its commitment to file a single-issue proceeding to address these impacts by June 30, 2019, if it has not yet filed a base rate case, appropriately balances the desire to expeditiously pass the benefits of the Tax Act to ratepayers with the Company's approach to efficiently adjusting its rates and charges to comprehensively address all base rate cost of service impacts resulting from the Tax Act. DENC maintained that if the Commission determines that it is appropriate to reduce utility rates through a rulemaking procedure on a more accelerated schedule, the Company recommends that the Commission only order DENC to adjust the income tax expense portion of operating income in the Company's cost of service and leave the other elements of the tax changes enacted in the Tax Act for review in the Company's next general rate case. DENC stated that, in any case, it stands ready to work with the Public Staff and to take whatever action the Commission directs to provide the benefits of the Tax Act to the Company's customers.

Natural Gas Utilities

Piedmont noted that it proposes to flow-through tax reductions under its IMR mechanism, while deferring tax rate reductions on its base rates until its next general rate case proceeding where such deferral can be amortized and used to offset any requested base rate increase in that docket. Piedmont stated that for excess deferred income taxes, it proposes to establish a regulatory liability and, similar to the Commission's treatment of excess deferred income taxes in Docket No. M-100, Sub 138, would propose that these liabilities be addressed in the Company's next general rate proceeding as well.

Piedmont asserted that while some intervenors request that the Commission reduce customer rates and the utilities' revenues immediately to account for 100% of the impacts of the Tax Act, Piedmont submits that its proposals represent a more balanced approach. Piedmont recommended that customers receive an immediate benefit in the form of savings under the Tax Act through rate reductions commencing with its upcoming June 1, 2018 IMR rate adjustment, but that tax rate reductions on its base rates be deferred until its next general rate case proceeding.

Piedmont proposed to defer some of the savings associated with the Tax Act because customers benefit directly from a strong balance sheet and strong investment grade credit ratings through low cost of capital and strong access to capital during all market conditions. Piedmont stated that adopting an immediate pass-through of only the benefits under the Tax Act, in isolation and to the exclusion of other provisions of the Tax Act, would be detrimental to Piedmont's long-term financial stability and credit ratings. Piedmont noted that as an example of this type of impact of the Tax Act, on January 19, 2018, Moody's changed the rating outlook of Piedmont and 23 other utilities and utility holding companies from stable to negative in response to the financial impacts of the Tax Act and regulatory uncertainties related thereto. Piedmont stated that, in addition, one attribute of the Tax Act is that it will increase rate base at a faster rate than has been experienced in recent years due to the elimination of bonus depreciation for new capital investment going forward. Piedmont asserted that preserving the benefits of a lower tax rate until Piedmont's next general rate case will serve as a natural hedge against increasing rate base and help stabilize customer rates over the long run.

Piedmont maintained that, thus, in order to minimize the negative impacts of the Tax Act on Piedmont's cash flows and credit quality in the long run and stabilize customer rates, Piedmont fully supports the adoption of a balanced approach that provides customers some benefits now, and some later.

Water/Wastewater Utilities

No water/wastewater utility filed reply comments.

Other Parties

The Attorney General stated that many of the utilities do acknowledge in their initial comments that ratepayers should benefit from the recent reductions in the federal corporate income tax rate. However, the Attorney General maintained that the Commission should not adopt proposals put forth by utilities that would prevent consumers from receiving these benefits fully and immediately, as opposed to on a delayed basis.

The Attorney General asserted that as a matter of public policy, utility service should be economical, rates should be just and reasonable, and where a major change in federal taxes has had a substantial effect on the cost of public utility service, across all utilities, it is appropriate to flow through the benefit to North Carolina ratepayers.

The Attorney General noted that when Congress passed the Tax Reform Act of 1986, the Commission found that the significant reduction to the tax rate would have an immediate and favorable impact on the cost of providing public utility services to consumers in North Carolina and concluded that it was incumbent on the Commission to take the appropriate action as required so as to preserve and flow through to ratepayers, as a reduction to public utility rates, any and all cost savings realized in this regard which would otherwise accrue solely to the benefit of the stockholders. The Attorney General further noted that the North Carolina Supreme Court, affirming the Commission's final decision in that proceeding, observed that the purpose of the Commission's proceeding in 1986 was to take the effect of the reduction in tax rates and flow it through to the ratepayers. The Attorney General asserted that by responding quickly through the rulemaking proceeding, significant over-collections by public utilities were avoided and customers benefitted from prompt rate reductions.

The Attorney General maintained that, undeniably, as the Commission indicated in its January 3, 2018 Order initiating this proceeding, the impact of the recent reduction in the federal corporate income tax rate from 35% to 21% has a substantial downward impact on the cost of service for utilities. The Attorney General argued that, nevertheless, contrary to the long-standing North Carolina legal authorities and principles of sound ratemaking, many of the initial comments filed by investor-owned utilities indicate that they do not support promptly flowing through the full benefits of the December 22, 2017 enactment of the Tax Act in utility rate reductions to ratepayers. The Attorney General stated that, instead, most of the utilities propose to make accounting entries that defer part or all of the over-collection of income taxes to be considered in future rate proceedings. The Attorney General asserted that these proposals are not acceptable.

The Attorney General stated that the investor-owned public utilities in their initial comments do acknowledge that utility ratepayers should benefit from the changes in the federal corporate income tax rate; however, by and large they want to (a) delay as long as possible returning money collected from ratepayers for past income tax over-collections, (b) continue to over-collect income taxes until their next rate cases, and (c) avoid telling ratepayers the magnitude of these past and continuing over-collections.

The Attorney General noted that, for example, DEC/DEP stated in their initial comments that it is the Companies' intent that customers will receive the benefits of tax reform. However, the Attorney General maintained, despite the fact that both of the Duke Energy North Carolina subsidiaries have pending general rate cases, Duke has only supplied information in this proceeding from rate cases that used test years that are several years old, and also has suggested using deferral accounting, instead of a prompt rate reduction, to address part of the adjustment to cost of service revenues. The Attorney General stated that, further, DEC/DEP do not identify how much the Companies hold in accounts for ADIT, do not report the EDIT amount that they have accrued based on the reduction in federal income taxes, and do not propose to return any of the EDIT amounts to ratepayers until they file future general rate cases. The Attorney General maintained that instead, DEC/DEP propose to hold onto those excess funds, apparently for several years, as cost-free capital.

The Attorney General observed that other utilities also suggest limiting or deferring the benefit of income tax reform rather than flowing it through to ratepayers promptly. The Attorney General noted that DENC proposed to defer the amount that is accounted for provisionally, relating to the impact of tax reform on cost of service, and to hold onto the excess amount that has accrued in deferred income taxes for consideration in its next general rate case. The Attorney General noted that CWSNC made a similar proposal, and that Piedmont proposed to defer the benefits of tax reform for consideration in a future general rate case, other than with respect to revenues that are recovered in periodic surcharges for the Integrity Management Rider. The Attorney General specified that, like DEC/DEP, Piedmont did not reveal the current balances of ADIT and EDIT accounts.

The Attorney General argued that allowing utilities to hold onto the excess is particularly unreasonable if the utility has a pending general rate case or if rates were recently established. The Attorney General stated that DEC has acknowledged that it is appropriate to address the effect of tax reform in the pending DEC general rate case, but suggests that it is not appropriate to address tax reform in the pending DEP case because the evidentiary hearing has already been held in that case. The Attorney General asserted, however, that the fact that the evidentiary hearing has already occurred in the DEP case should not postpone action until another rate case is filed years from now. The Attorney General argued that the effects of the changes in the tax law are known and measurable, and may be addressed either in late-filed exhibits or by identifying the increment in rates relating to the Tax Act as provisional, pending further consideration and determination similar to the provisional treatment ordered in this proceeding. The Attorney General maintained that, alternatively, the rates established in the general rate case may be adjusted subsequently by findings made in this rulemaking proceeding with reliance on factors determined in the rate case proceeding.

The Attorney General argued that the Commission should not be persuaded to delay rate reductions based on the justification offered by DEC/DEP for continuing to over-collect from ratepayers and to delay returning over-collections. The Attorney General stated that DEC and DEP contend that prompt action to flow over-collected taxes back to customers will affect DEC/DEP's cash flow and may therefore harm ratepayers. The Attorney General maintained that it appears from DEC/DEP's comments that DEC/DEP and other utilities have experienced high cash flows in recent years in part because their rates are established based on the inclusion in their revenue requirements of the full federal corporate income tax rate, whereas income taxes actually incurred and paid may be significantly less than that due to bonus depreciation and other factors. The Attorney General stated that DEC/DEP's comments propose to continue over-collecting the known and measurable adjustment to its expense for income taxes because of a hypothetical impact that rate reductions and the return of excess funds would have on DEC/DEP's credit rating. The Attorney General asserted that the fact that Moody's has placed Duke Energy Corporation on a credit watch for possible downgrade does not mean that the credit ratings of Duke Energy or its North Carolina subsidiaries will suffer. The Attorney General argued that far less does it provide evidence of the extent or effect of such a downgrade. The Attorney General maintained that Duke's credit rating is high relative to many of its peers, and the effect of a slight downgrade would be small relative to the benefit ratepayers receive from a rate reduction and the return of excess funds held by Duke. The Attorney General stated that DEC/DEP's argument unfairly seeks to maintain unreasonably high utility rates merely to prop up DEC/DEP's cash flow, without any attempt to weigh the relative benefits and harms that its proposal would have on ratepayers.

The Attorney General noted that DEC/DEP suggest that the substantial beneficial impact of the federal corporate income tax rate reduction provides headroom for the Commission to allow rate increases that DEC and DEP support but other parties have disputed, such as for high coal ash costs, storm costs, and accelerated depreciation of some meters. The Attorney General argued that, however, ratepayers will not benefit if income tax-related utility rate reductions are used to mask unreasonable cost recovery proposals.

The Attorney General maintained that as a result of the scant information provided by the utilities in their initial comments, the public and the Commission do not know how much EDIT have been accrued. The Attorney General argued that, however, this information is known to the utilities because publicly-traded utilities must report this data in their annual reports to shareholders, and the information should be reported and considered in this docket as well. The Attorney General maintained that the amount of EDIT may be very large. The Attorney General further noted that according to an estimate provided in comments filed by CUCA, based on FERC Form 1 filings, DEC has over $1.6 billion of excess accrued deferred income taxes allocated to North Carolina retail customers, and DEP has approximately $875 million.

The Attorney General argued that the utilities' proposals are unjust and unreasonable to ratepayers. The Attorney General stated that to the extent that the cost of service effect associated with the lower corporate income tax rate is not flowed through in rates, utilities will continue to over-collect revenues, and customers will continue to be forced to pay excessive rates to build up utility accounts that essentially lend cost-free capital for utility operations. The Attorney General stated that, similarly, if the utilities' proposals are accepted and they are allowed to retain the funds they are currently holding in EDIT accounts, i.e., excess deferred income taxes that were collected in earlier years when the federal income tax rate was higher than it is following the Tax Act, then the utilities would continue to maintain these excess funds as cost-free capital. The Attorney General argued that not returning dollars to consumers who struggle to pay their bills, or to consumers who would use their money for different purposes if given the opportunity, results in an undue burden on ratepayers and communities in North Carolina.

The Attorney General requested that the Commission take prompt action to require the utilities to provide a full accounting of the past and present extent of over-collection of taxes and then to order immediate utility rate reductions that reflect the full impact of the federal income tax reduction on cost of service and that return excess deferred income taxes that have accrued as soon as allowed under federal tax law.

CIGFUR noted that because income taxes are a major component of utility revenue requirements, the Tax Act will have a substantial and material impact on public utilities' revenue requirements and consequently on the ratepayers of these utilities. CIGFUR stated that DENC estimated in its initial comments that its annual North Carolina jurisdictional income tax expense will decrease by approximately $10.8 million with a corresponding increase to operating income of the same amount beginning January 1, 2018. CIGFUR also noted that DEC/DEP estimated in their initial comments that the Tax Act results in a reduction of $104 million in DEP's annual revenue requirement and a reduction of $172 million for DEC.

CIGFUR argued that the Commission should adjust customer rates to pass tax savings onto ratepayers in the form of rate decreases as soon as practicable. CIGFUR maintained that DENC acknowledged that it is now treating the federal corporate income tax component of its existing approved rates and charges as provisional and will hold the amounts in a deferred account. CIGFUR stated that DENC proposed to address the cost of service impacts and disposition of deferred amounts due to the Tax Act through its next general rate case. CIGFUR further stated that with respect to DEP, the Company proposed to defer the tax savings to a regulatory liability, until DEP's next rate case, but also offers an alternative that the Commission could approve a rider in this generic docket (Docket No. M-100, Sub 148) to reduce DEP customer rates. CIGFUR noted that with respect to DEC, the Company proposed that federal tax reform impacts should be addressed in its pending general rate case, Docket No. E-7, Sub 1146.

CIGFUR maintained that it supports implementing the federal corporate income tax reduction through the general rate case process for utilities with pending general rate case proceedings, and thus supports DEC's proposal to address the Tax Act through its pending rate case, Docket No. E-7, Sub 1146. However, CIGFUR stated that it opposes DENC's and DEP's proposals to defer cost savings until their next general rate cases, which may not occur for several years. CIGFUR rather recommended that the Commission consider the holistic impact of the Tax Act and adjust customer rates to pass tax savings onto ratepayers in the form of rate decreases as soon as practicable.

CIGFUR further stated that EDIT should be refunded to ratepayers through a decrement rider as soon as practicable. CIGFUR maintained that in the early years of a given capital asset, the utility collects more in tax expense from ratepayers than it pays out to the IRS due to the difference in accelerated depreciation for tax purposes and straight-line depreciation for ratemaking purposes. CIGFUR noted that that situation reverses once the ratemaking depreciation expense begins to exceed the tax depreciation. CIGFUR asserted that assuming that tax rates stay constant over the life of a capital asset, the total tax expense paid by the ratepayers to the utility should match the tax expense the utility pays the IRS. CIGFUR stated that as a result of the differences in depreciation timing and because tax funds are ratepayer supplied, in the early years of a given capital asset ratepayers provide the utility an interest-free loan, reflected as a credit to the utility's ADIT liability account.

CIGFUR maintained that due to the Tax Act, DENC's, DEP's, and DEC's future tax liabilities will not be as high as anticipated when rates were originally designed. CIGFUR stated that the amount by which DENC's, DEP's, and DEC's current ADIT balances exceeds their future income tax liability as a result of the Tax Act are the EDIT at issue. CIGFUR noted that further, until the Commission adjusts utility rates to reflect the new lower tax rate, the utilities will continue to collect excess income tax from ratepayers at the 35% tax rate, which the Commission approved for DENC, DEP, and DEC in Docket Nos. E-22, Sub 532, E-2, Sub 1023, and E-7, Sub 1026, respectively.

CIGFUR asserted that these EDIT should be promptly flowed back to ratepayers; however, DENC, DEP, and DEC argue against returning EDIT to ratepayers in a timely manner and instead propose to defer their EDIT as regulatory liabilities until their next general rate cases. CIGFUR stated that it opposes long-term deferral of EDIT and proposes that, concurrent with the immediate rate reductions discussed in its reply comments, the Commission establish a decrement rider for each utility to refund EDIT to ratepayers over a two or three year period.

CIGFUR concluded by stating that it opposes the long-term deferral of tax savings and proposes that as soon as possible the Commission reduce customer rates to pass the substantial and material benefits of the Tax Act onto ratepayers and concurrently establish decrement riders to refund EDIT.

The <u>Low-Income Advocates</u> stated that the crucial question before the Commission remains how best to take advantage of the federal tax cut for the benefit of customers. The Low-Income Advocates asserted that the Commission should reject the utilities' proposals to retain the benefits of the tax reduction. The Low-Income Advocates maintained that the Commission should not follow DEC/DEP's, DENC's, or Piedmont's recommendations. The Low-Income Advocates noted that, first, in the case of DEC/DEP, their pending rate cases are not yet decided. The Low-Income Advocates argued that it would be premature to set aside funds that belong to customers now for costs that have not yet been authorized by the Commission as an appropriate cost of service. The Low-Income Advocates stated that even though an order from the Commission in the DEP rate case is likely to be issued soon[1], given the possibility of appeal, the contested issues will not likely be fully resolved for some time. The Low-Income Advocates noted that Duke and the other regulated public utilities should not be allowed to continue over-collecting or to hold on to previously over-collected deferred taxes pending the resolution of those contested issues.

[1] The Commission issued the DEP rate case Order on February 23, 2018.

The Low-Income Advocates noted that, moreover, even if all of the contested issues were quickly resolved in DEP's and DEC's pending rate cases, the basis for those rates would include outdated figures for tax collections within the utilities' base rates, and would thus lead to an over-collection and inflated rates for customers unless they were adjusted by the Commission. The Low-Income Advocates stated that, in addition, the longer the lag time in adjusting rates to account for the dramatically reduced tax liabilities faced by the utilities, the greater chance that some ratepayers will not receive any benefit from the utilities' tax cut. The Low-Income Advocates maintained that, for example, a Duke customer who paid rates over the last several years was over-paying for both excess accumulated deferred income taxes and, since January 1, 2018, for the income-tax component of Duke's cost of service. The Low-Income Advocates stated that if that customer moves out of Duke's service territory before any adjustments are made by the Commission, the customer will never recoup those overpayments.

The Low-Income Advocates asserted that the Commission should direct the utilities to use the tax savings to reduce fixed monthly charges. The Low-Income Advocates urged the Commission to require the utilities, as soon as practicable, to first apply the tax reductions to reduce utilities' fixed, monthly charges. The Low-Income Advocates stated that this will not only lower customers' bills, it will maximize the chance that low-income customers, who are disproportionately low-volume customers, receive the full value of benefit from such a reduction. The Low-Income Advocates maintained that applying the reductions to the fixed charges also guarantees that all customers will get an equal benefit from the reduced rates. The Low-Income Advocates stated that otherwise, high-volume users would potentially see a greater reduction in their bills than would a low-volume user.

The Low-Income Advocates recommended that the Commission order a portion of the previously over-collected taxes (EDIT) to flow back to ratepayers in the form of investments in low-income efficiency programs. The Low-Income Advocates asserted that the accumulated deferred income taxes have already been collected from customers, and given the change in the federal corporate income tax rate enacted by Congress, have been over-collected. The Low-Income Advocates stated that this excess is now a regulatory liability that should be returned to customers. The Low-Income Advocates noted that consistent with the requirements for the normalization method of accounting for deferred taxes for regulated public utilities, the public utilities in this docket should return the difference between the deferred income taxes accounted for under the higher federal corporate income tax rate under prior law and the lower rate that was recently established in the Tax Act. The Low-Income Advocates asserted that a portion of the EDIT should be returned to ratepayers in the form of direct investments in low-income energy efficiency. The Low-Income Advocates noted that based on the initial comments it is not clear what the total change in the EDIT will be over the next several years, or how fast the utilities can return the over-collected deferred income taxes to ratepayers under normalization rules. The Low-Income Advocates stated that at a minimum, it would be reasonable for the public utilities to invest at least 25% of EDIT for low-income efficiency.

The Low-Income Advocates further stated that for DEP and DEC, this objective can most readily be achieved by directing a portion of their EDIT to the Helping Home Fund, a program administered by the North Carolina Community Action Association that supplements the federal Weatherization Assistance Program by providing efficiency upgrades to low-income households.

The Low-Income Advocates asserted that there is precedent for using a regulatory liability for the benefit of retail customers to fund energy-efficiency investments for the utility's low-income customers. The Low-Income Advocates noted that the Helping Home Fund was itself established out of a $20 million regulatory liability from DEP (in the context of its 2013 general rate case proceeding stipulation) for the benefit of its North Carolina low-income residential customers.

The Low-Income Advocates maintained that as to DENC, it could replicate the Helping Home Fund in DENC's North Carolina territory with the assistance of community action agencies that operate in the Northeast corner of the State. The Low-Income Advocates stated that the gas and water utilities could direct a portion of EDIT to their existing efficiency programs for low-income customers, or propose alternative methods for making direct investments in low-income efficiency programs.

The Low-Income Advocates stated that there are several sound policy reasons for using some of the already over-collected tax revenues for targeted investment in low-income energy efficiency rather than rebates or a decrement rider.

The Low-Income Advocates maintained that based on an ACEEE 2014 Press Release (http://aceee.org/press/2014/03/new-report-finds-energy-efficiency-a) each dollar invested in energy efficiency yields up to $4 in benefits for customers. The Low-Income Advocates asserted that, based on information in the same ACEEE Press Release, investments in energy efficiency reduce customer bills, lower energy costs during periods of high demand, avoid or defer the need to build or upgrade power plants and transmission infrastructure, and reduce air and water pollution. The Low-Income Advocates stated that energy efficiency is the least-cost energy resource; the energy savings achieved through energy efficiency programs are approximately one-half to one-third the cost of generating the same amount of electricity from traditional sources such as fossil fuels.

The Low-Income Advocates stated that low-income households are more likely than the average household to have older and less efficient appliances. The Low-Income Advocates further noted that low-income households, minority households, renting households, and low-income households residing in multifamily buildings experience higher than average energy burdens, meaning that they pay a higher percentage of their income on energy bills. The Low-Income Advocates asserted that the Southeast faces some of the highest energy burdens in the nation and that households with high energy burdens must face difficult trade-offs between paying utility bills and paying for other necessities such as food, prescriptions, transportation, and medical care. The Low-Income Advocates noted that utility investments in energy efficiency help to alleviate high energy burdens faced by low-income households while bringing system-wide benefits that are shared by all customers.

The Low-Income Advocates urged the Commission to use the reduced income tax portion of the public utilities' cost of service to lower customer bills as soon as possible. The Low-Income Advocates asserted that this should take the form of lower fixed, monthly charges for residential customers and for a portion of the EDIT, the utilities should make investments in efficiency measures that directly benefit low-income customers, such as the Helping Home Fund.

Nucor noted that it owns and operates a steel recycling facility located in Hertford County, North Carolina, that produces steel plate. Nucor stated that it is a customer of DENC and takes service pursuant to a special contract for electric service, as amended, subject to the jurisdiction of the Commission. Nucor maintained that it, therefore, reviewed DENC's initial comments in this proceeding and has concerns regarding DENC's planned ratemaking in response to the Tax Act.

Nucor noted that DENC indicated that it will comprehensively address all impacts from the Tax Act as part of its updated cost of service filed in the Company's next general rate case. Nucor asserted that DENC's proposed approach is inadequate and objectionable.

Nucor argued that DENC makes no commitment as to when it will file its next general rate case application[1]. Further, Nucor stated that DENC initiated its last general rate case, Docket No. E-22, Sub 532, on March 31, 2016. Nucor noted that that proceeding was not resolved until issuance of the Commission's Order on December 22, 2016. Nucor asserted that the inherent delay in flowing through the federal tax reductions to DENC's customers via a speculative and lengthy general rate case proceeding is unwarranted and would be unfair to DENC's customers.

Nucor stated that as the Attorney General correctly observes, this is not the first time the Commission has dealt with this very issue. Nucor noted the 1990 North Carolina Supreme Court decision concerning the Commission's treatment of the 1986 Federal Tax Act.

Nucor maintained that the Commission has the authority to address the tax reduction resulting from the Tax Act outside of a general rate case and should do so with respect to DENC. Nucor asserted that the Commission should require that DENC pass through the benefits of the federal tax changes to DENC's ratepayers in a timely manner.

The **Public Staff** maintained that Toccoa, in its initial comments, noted that, as a municipally-owned natural gas system, it is not subject to income and other tax obligations. The Public Staff further noted that Toccoa asserted that, consequently, no tax allowances were included in the determination of Toccoa's revenue requirement when its rates were established, and no adjustment to its rates are required as a result of the Tax Act. The Public Staff stated that, for the reasons set forth in Toccoa's comments, it agrees that no adjustment should be made to Toccoa's rates in response to the tax reduction in the Tax Act.

The Public Staff commented that based on its review of the Tax Act and the initial comments of the other parties, it has the following proposals.

The Public Staff recommended that the Commission seek to resolve issues raised in this docket in any pending general rate cases for the utilities subject to the provisions of this docket (the subject utilities). The Public Staff stated that currently, DEC has a pending rate case in Docket No. E-7, Sub 1146. The Public Staff recommended that the issues raised in this docket be addressed in that general rate case.

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[1] In its reply comments, DENC committed to filing a single-issue adjustment to its base rate cost of service on or before June 30, 2019 if the Company has not filed a general rate case as of that date.

Further, the Public Staff stated that it does not oppose Aqua's request to resolve the issues raised in this docket related to the income tax changes resulting from the Tax Act in the general rate proceeding it intends to file, provided Aqua files a general rate case on or before April 1, 2018[1].

The Public Staff noted that the Commission has dealt with similar issues in two prior Commission proceedings in Docket Nos. M-100, Sub 113 and M-100, Sub 138. The Public Staff commented that in Docket No. M-100, Sub 113, the Commission addressed tax reductions from the Federal Tax Reform Act of 1986. The Public Staff maintained that, among other things, the Federal Tax Reform Act of 1986 reduced the top corporate income tax rate from 46% to 34%. The Public Staff stated that in Docket No. M-100, Sub 138, the Commission addressed the tax reductions from House Bill 998 (S.L. 2013-316), which, among other things, changed the net State income tax rate imposed on C Corporations and amended the gross receipts and franchise taxes.

Further, the Public Staff recommended that the Commission direct the subject utilities to reduce their rates to reflect any and all cost savings resulting from the reduction in the federal corporate income tax expense component of the cost of providing utility service as soon as practicable. The Public Staff asserted that the rates for riders should also be reduced in each subject utility's respective annual rider filings to reflect the reduction in the federal corporate income tax rate.

The Public Staff also recommended that the Commission direct the subject utilities to refund the amount collected in the deferred account established by the Commission in this proceeding that represents the difference between revenues billed under the prior federal income tax rate and the federal income tax rate resulting from the Tax Act starting January 1, 2018.

The Public Staff maintained that, as in Docket Nos. M-100, Sub 113 and M-100, Sub 138, the Commission should require that the EDIT resulting from the decrease in the federal corporate income tax rate established in the Tax Act be flowed back to the ratepayers. The Public Staff asserted that the treatment of EDIT in those dockets should provide a framework for the treatment of EDIT created by the Tax Act.

The Public Staff stated that the Tax Act provides that certain EDIT should be flowed back to the ratepayers subject to certain limitations. The Public Staff specified that the EDIT subject to these limitations is generally referred to as the "protected EDIT." The Public Staff noted that the EDIT that is not subject to limitations in the timing of flow back is generally referred to as the "unprotected EDIT."

The Public Staff asserted that the protected EDIT should be flowed back as soon as practicable in accordance with federal tax normalization rules. The Public Staff stated that compliance with federal tax normalization rules slows the return of the protected EDIT to ratepayers as compared to what regulators might otherwise desire. The Public Staff stated that it

[1] Aqua filed its general rate case application on March 7, 2018 in Docket No. W-218, Sub 497.

does not recommend delaying the return of the protected EDIT or in any way further slowing the return of the protected EDIT to ratepayers, other than the delay required under federal law.

The Public Staff further recommended that the flow back of the unprotected EDIT should be addressed in the next general rate case filed by each of the subject utilities, except for those with currently pending general rate cases, as previously noted.

The Public Staff stated that arguments raised by the subject utilities related to cost of capital and cash flow should not be addressed in this docket. The Public Staff argued that absent compelling evidence of financial harm to the utilities, the ratepayers should receive the benefit of the tax reductions from the Tax Act as soon as possible. The Public Staff asserted that cost of capital is appropriately addressed in a general rate case. The Public Staff maintained that if a subject utility believes its cost of capital has changed and earnings are insufficient to achieve the new cost of capital, it should file a general rate case to address this issue.

The Public Staff also noted that the Tax Act changes the taxable treatment of CIAC for water and wastewater companies. The Public Staff stated that this could have a significant impact on water and wastewater companies in that contributed plant is a significant portion of the plant additions by these companies. The Public Staff recommended that the Commission open a new docket to address the implications of the inclusion of CIAC in taxable income for water and wastewater companies. The Public Staff further recommended that the treatment of CIAC should follow the precedent established in Docket No. M-100, Sub 113, and that water and wastewater companies should seek to collect the income tax on CIAC from the contributor using the full gross-up method. The Public Staff recommended that the Commission allow individual companies seeking to use the present value method to do so with prior approval of the Commission. The Public Staff recommended that in opening a new docket, the Commission should provide notice of this change to all water and wastewater companies, not just the utilities subject to this docket, and direct those companies to seek to collect the income tax on CIAC from contributors of plant for new contributions contracted for on or after the date of the opening of that new docket.

The Public Staff also noted that Frontier asserted that its rates are not based on cost of service, and therefore, it should not be subject to this docket. The Public Staff asserted that Frontier has been collecting funds from its ratepayers in order to pay Frontier's federal income tax obligations. The Public Staff stated that the Tax Act reduces the federal tax obligations of Frontier and that its ratepayers should benefit from the reduction in the federal corporate income tax resulting from the Tax Act. Accordingly, the Public Staff recommended that Frontier be subject to the provisions of this docket.

Finally, the Public Staff stated that to implement the recommendations outlined in its reply comments, the Public Staff requested that the Commission direct the subject utilities to file with the Commission and the Public Staff rate reductions to address the changes by March 30, 2018. The Public Staff stated that the subject utilities should also be required to file workpapers with the Commission and the Public Staff to support the rate reduction calculations. The Public Staff maintained that once rates are established, the subject utilities should continue to file quarterly reports on the status of their EDIT deferred account, and the deferral account established under this proceeding that represents the difference between revenues billed under the prior federal income tax rate and the federal income tax rate resulting from the Tax Act starting January 1, 2018.

PUBLIC STAFF CLARIFICATION TO REPLY COMMENTS

The Public Staff noted that on February 20, 2018, it filed reply comments in this docket. The Public Staff maintained that regarding Frontier, the Public Staff stated the following:

> "Frontier asserts that its rates are not based on cost of service, and therefore, it should not be subject to this docket. Frontier has been collecting funds from its ratepayers in order to pay Frontier's Federal income tax obligations. The Act reduces the Federal tax obligations of Frontier and its ratepayers should benefit from the reduction in the federal corporate income tax resulting from the Act. Accordingly, the Public Staff recommends that Frontier be subject to the provisions of this docket."

The Public Staff maintained that in Docket No. G-40, Sub 136, the Commission approved a merger between Frontier and FR Bison Holdings, Inc., subject to certain regulatory conditions. The Public Staff noted that Regulatory Condition #10, provided that the Public Staff would not request a change in Frontier's margin rates unless certain exceptions apply. The Public Staff stated that the Regulatory Condition in its entirety reads:

> "**Rate Case Moratorium.** Neither Frontier nor the Public Staff will request a change in Frontier's margin rates until after December 31, 2021, except as set forth below. For purposes of this provision, the margin rate is defined as the tariff rate less the benchmark cost of gas and temporary increments and/or decrements imposed pursuant to G.S. 62-133.4 or Commission Rule R1-17(k). The exceptions to the moratorium imposed by this Condition are as follows: (a) Should Frontier or the Public Staff believe that Frontier should implement a pipeline safety rate adjustment mechanism pursuant to G.S. 62-133.7A, either party shall have the right to apply to or petition the Commission to initiate a general rate case proceeding; and (b) effective July 1, 2019, should Frontier's rolling twelve-month earned return on average rate base, based on a reasonable pro forma capital structure and reasonable regulatory adjustments, exceed 12.00% for two quarters in any consecutive four-quarter period, the Public Staff shall have the right, after notice to and consultation with Frontier's management, to petition the Commission to initiate a general rate case proceeding."

The Public Staff asserted that, consistent with the Regulatory Condition, the Public Staff seeks to clarify that in its comments submitted on February 20, 2018, the Public Staff is not requesting the Commission to change Frontier's margin rates. The Public Staff stated that it recognizes that the Commission is not bound by the Public Staff's agreement with Frontier with respect to any change in margin rates and may find in its discretion that Frontier should be directed to reduce its rates to reflect the changes in the Tax Act. The Public Staff stated that, notwithstanding the foregoing, the Public Staff does request that Frontier be subject to any reporting requirements adopted in this docket.

DEC/DEP SUPPLEMENTAL COMMENTS

DEC/DEP requested that the Commission accept its Supplemental Comments that take into consideration the Commission's February 23, 2018 DEP rate case Order and the reply comments filed by other parties in the docket. DEC/DEP stated that their Supplemental Comments offer more specific proposals on how DEC and DEP could implement the impacts of the Tax Act to benefit customers.

DEC/DEP stated that after now having had the opportunity to review the DEP rate case Order, as well as the reply comments filed by the other parties in this docket seeking more detailed information, the Companies proposed to accomplish this intention through specific solutions that will lower customer bills in the near-term, help mitigate volatility due to future customer rate increases, and protect the Companies' pre-Tax Act credit quality for the benefit of customers. DEC/DEP stated that DEC proposes to incorporate these benefits into its pending base rate case proceeding in Docket No. E-7, Sub 1146, and DEP proposes to address the adjustments either through its next base rate case proceeding or through a decrement rider established by the Commission in this proceeding.

DEC proposed several adjustments to reduce the amounts of its requested rate increase in its pending general rate case in Docket No. E-7, Sub 1146 to reflect the changes in the Tax Act. DEC noted that in its proposed rate request filed in Docket No. E-7, Sub 1146, DEC's proposed rate increase of $647 million reflects a federal corporate income tax rate of 35%. DEC stated that the underlying test period income tax expense and all pro forma adjustments related to income tax expense reflect a federal corporate income tax rate of 35%. DEC maintained that, in addition, the proposed rate increase reflects accumulated deferred tax amounts in rate base without adjusting for the change in tax rate. DEC stated that to address the federal corporate income tax rate change, the Company proposes that customer rates authorized by the Commission should:

(1) Incorporate a $216 million reduction in revenue requirements to reflect federal corporate income taxes at a 21% rate, rather than a 35% rate. DEC noted that the $216 million is the $241 million on Line 8 of Boswell Supplemental Exhibit 1, Schedule 1, Page 1, Revised, in Docket No. E-7, Sub 1146, minus $25 million to reflect the tax rate impact on the additional adjustments that DEC agreed to in rebuttal testimony and in the partial settlement filed in that docket. DEC stated that the Public Staff has already incorporated the tax rate change impact into its partial settlement and additional adjustments;

(2) Incorporate reductions totaling $96 million in proposed revenue requirements to return EDIT to customers under the following proposals:

    (a) <u>Protected Federal EDIT related to Property, Plant and Equipment</u>

    DEC proposed to return EDIT for which there are IRS requirements (protected deferred income taxes) based on the method required by IRS rules. DEC stated that specific IRS rules apply to deferred income taxes related to property, plant and equipment for which there are differences in book versus tax depreciation with regard to method of depreciation and depreciable life. DEC proposes to reduce its revenue requirements by \$34 million to return approximately 3.1% of the balance of EDIT to customers annually over the remaining life of the property, plant and equipment to which the deferred taxes are related. DEC stated that this proposal complies with IRS tax normalization rules. DEC maintained that the revenue requirement reduction of \$34 million is a net amount that incorporates both the decrease in operating expenses related to the tax rate change and the increase in rate base associated with the lesser amount of accumulated deferred income taxes that are deducted from rate base.

(b) Unprotected Federal EDIT related to Property, Plant and Equipment

DEC noted that for EDIT related to property, plant and equipment, but not subject to IRS tax normalization rules, DEC proposes to return that EDIT over 20 years. DEC proposes to reduce its revenue requirements by \$37 million per year. DEC stated that this proposal serves to refund the excess tax amounts over a period that considers the long lives of the property, plant and equipment to which these tax amounts relate. DEC stated that this period aligns with the timeframe that the benefits (i.e., deferred tax liability offset to rate base) would be received by customers absent the change in tax rate. DEC maintained that the revenue requirement reduction of \$37 million is a net amount that incorporates both the decrease in operating expenses related to the tax rate change and the increase in rate base associated with the lesser amount of accumulated deferred income taxes that are deducted from rate base.

(c) Unprotected Federal EDIT – Other

DEC stated that it proposes to return over five years through a rider EDIT related to timing differences between book income and taxable income that are: (1) not subject to IRS normalization rules; and (2) are not related to property, plant and equipment. DEC noted that the rider would incorporate a \$40 million reduction in operating expense per year over the five year period. DEC maintained that the reduced accumulated deferred income taxes that are deducted from rate base equate to approximately \$15 million and will be reflected in base rate adjustments rather than the rider. DEC stated that these represent a partial offset to the impact to rate base; and

(3) Incorporate an increase in proposed revenue requirements of \$200 million to collect certain expenses on an accelerated basis. DEC stated that in doing so, the Company intends to minimize customer rate volatility, and minimize financing costs over the long term.

DEC stated that the reduction in the federal corporate income tax rate has a dual effect on customer rates – a decrease in operating expenses and an increase in rate base. DEC noted that this accelerated return of EDIT to customers creates a rate reduction that is followed by a rate increase. DEC stated that its proposal would smooth out this rate volatility. DEC maintained that this approach does not ask customers to pay costs that are not appropriate costs of providing electric service, but rather adjusts the timing of payment of the costs in a manner that minimizes steep changes in rates. DEC stated that the amount of accelerated expense recovery proposed by the Company, although discretionary, is designed to achieve this objective.

DEC asserted that one option would be for the Commission to allow DEC to record \$200 million per year for accelerated depreciation for AMR meters and/or certain coal-fired plants. DEC stated that under this option, customers would benefit in the future through lower depreciation expense following the next depreciation study.

DEC stated that another option is for the Commission to use this reduction in the federal corporate income tax rate to offset the ongoing necessary investments in coal ash basin closure expense to comply with the EPA's Coal Combustion Residuals Rule and the North Carolina Coal Ash Management Act. DEC maintained that if the Commission were to deny DEC's request for ongoing recovery of annual coal ash basin closure expense (the ongoing compliance costs) in DEC's pending rate case, DEC would propose to record \$200 million amortization expense per year to the same regulatory asset to which the ongoing compliance costs are recorded, thereby reducing customers' future obligation.

DEC noted that the net effect of the proposed adjustments to the revenue increase requested in Docket No. E-7, Sub 1146 is a reduction of \$72 million in base rates, plus an annual revenue reduction of \$40 million through a five-year rider, for a total benefit to customers of \$112 million per year for five years. DEC/DEP stated that they have proposed that the Commission could mitigate these impacts by offsetting items such as storm response costs, ongoing coal ash basin closure compliance costs or other environmental compliance costs, or accelerating the depreciation of certain assets such as the existing AMR meters or coal plants. DEC/DEP noted that the accelerated depreciation would be accomplished by creating a North Carolina retail regulatory liability and that liability would then be used to reduce depreciation expense on the specific asset or group of assets the next time depreciation rates are updated, similar to the way that the DEP Harris Nuclear Plant accelerated depreciation was used to reduce depreciation expense in Docket No. E-2, Sub 1023.

DEC stated that the amounts set forth in its proposal are based on DEC's rebuttal testimony and Agreement and Stipulation of Partial Settlement with the Public Staff in Docket No. E-7, Sub 1146. DEC/DEP maintained that any further changes to proposed revenue requirements resulting from the Commission rulings in Docket No. E-7, Sub 1146, such as the return on equity authorized by the Commission, may affect these amounts. DEC/DEP noted that, in addition, all EDIT amounts are by necessity estimated, pending completion of the Company's federal income tax return in 2019 for tax year 2018.

DEC stated that it is proposing an approach to reduce customer bills in the near term and help to offset rate increases in the future. DEC maintained that, importantly, customers benefit if the Company can access low-cost capital – this allows the Company to keep bills as low as possible while making the investments necessary to build the energy future customers expect. DEC argued that this is possible because the Company maintains strong credit quality and any treatment of tax reform should support maintaining the Company's pre-Tax Act credit quality. DEC stated that its approach will balance the importance of delivering savings to customers and upholding the Company's financial strength, which ultimately benefits customers.

DEC/DEP noted that the Commission's DEP rate case Order required DEP to recalculate a revenue requirement and file it for approval with the Commission. DEC/DEP stated that DEP is working with the Public Staff to complete these calculations[1]. DEC/DEP maintained that DEP proposes to make a supplemental filing in the future which proposes more specific recommendations after the Commission has approved a compliance revenue requirement in Docket No. E-2, Sub 1142.

PUBLIC STAFF'S MARCH 2, 2018 LETTER

The Public Staff stated that DEC has failed to provide its proposal as outlined in its March 1, 2018 Supplemental Comments in the multiple supplemental filings filed in its pending general rate case in Docket No. E-7, Sub 1146. The Public Staff noted that, instead, DEC filed its proposal in this docket, which in all likelihood will be resolved after the Commission's Order in DEC's pending rate case, thus delaying the flow back of the benefits of the Tax Act.

The Public Staff maintained that it believes the Supplemental Comments should not have been filed in this docket and the issues raised in the Supplemental Comments are more appropriately handled in DEC's pending general rate case. The Public Staff commented that its proposals for implementing the impacts of the Tax Act in DEC's general rate case are set forth in the direct and supplemental testimonies of witness Michelle Boswell and, thus, there is sufficient evidence in the rate case docket for resolving this issue. The Public Staff further stated that as a general rulemaking docket, the appropriate matters to be considered in this docket are the general manner in which the Commission will direct the utilities subject to this docket to flow back both the immediate reduction in the income tax expense and the EDIT resulting from the Tax Act. The Public Staff noted that DEC's Supplemental Comments proposed specific accounting rate base adjustments to offset the impact of the reduced tax rate, which are inappropriate for a general rulemaking docket and only can be resolved in the pending general rate case. The Public Staff asserted that ratepayers should receive the benefit of the tax reductions from the Tax Act as soon as possible and that the Commission should implement the impacts of the Tax Act in DEC's pending general rate case.

DEP'S SUPPLEMENTAL COMMENTS

DEP stated that its supplemental comments take into consideration the Commission's February 23, 2018 Order in DEP's general rate case proceeding, the reply comments filed by other parties in this docket, and the Commission's March 8, 2018 Order Approving Compliance Filing and Change in Rates in DEP's general rate case proceeding.

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[1] DEP filed the calculations on March 2, 2018, and the Commission issued its Order approving the compliance filing and change in rates on March 8, 2018.

DEP stated that its supplemental comments update DEP's estimated annual cost of service effect of the changes to the levels of income tax expenses expected due to the Tax Act provided in DEP's initial comments in this docket. DEP maintained that this update is based on the revenue requirement approved by the Commission in its March 8, 2018 Order Approving Compliance Filing and Change in Rates. DEP stated that the supplemental comments also outline DEP's more specific proposal as promised in DEC/DEP's March 1, 2018 supplemental comments filed in this docket.

DEP asserted that it continues to propose that the benefits of the Tax Act be addressed in the Company's next general rate case proceeding or through a decrement rider established by the Commission in this proceeding.

DEP provided an updated estimated effect of the Tax Act on DEP's cost of service approved in its recent rate case. DEP noted that the rates based on this cost of service study will become effective for service rendered on or after March 16, 2018. DEP further noted that the resulting reduction in annual revenue requirement is $104 million which was also the estimate provided in DEP's initial comments in this docket based upon its 2013 rate case.

DEP stated that this updated $104 million reduction is comprised of a $111 million decrease in base rates and a $7 million increase in the NC EDIT rider both related to the lower federal corporate income tax rate. DEP stated that Updated Exhibit 2b shows how the revenue requirement reduction translates into a decrement rate of $0.00278 per kWh. DEP stated that it plans to update the decrement to the new rate shown in Updated Exhibit 2b and to apply it to North Carolina retail services provided beginning March 16, 2018. DEP further stated that it would propose to continue this deferral until new rates can be established in its next general rate case proceeding. DEP maintained that should the Commission decide to order a rate change in this docket which incorporates this impact, DEP would stop the deferral when the new rates became effective.

DEP asserted that while it continues to propose that the benefits of the Tax Act be addressed in the Company's next general rate case proceeding, should the Commission decide to reduce customers' rates in this docket instead, DEP submits the following proposal to benefit customers in the short-term and long-term.

1. Incorporate a $104 million reduction in revenue requirements to reflect federal corporate income taxes at a 21% rate, rather than a 35% rate.

2. Incorporate reductions totaling approximately $45 million in proposed revenue requirements to return excess accumulated deferred income taxes to customers under the following proposals:

<u>Protected Federal EDIT related to Property, Plant and Equipment</u>

Return EDIT for which there are IRS requirements (protected deferred income taxes) based on the method required by IRS rules. Specific IRS rules apply to deferred income taxes related to property, plant and equipment for which there are differences in book versus tax depreciation. These differences are related to the method of depreciation and depreciable life. DEP would propose to reduce its revenue requirements by approximately $37 million to return approximately 4.29% of the balance of excess deferred taxes to customers annually over the remaining life of the property, plant and equipment to which the deferred taxes are related. This proposal complies with IRS tax normalization rules. The revenue requirement reduction of $37 million is a net amount that incorporates both the decrease in operating expenses related to the tax rate change and the increase in rate base associated with the lesser amount of accumulated deferred income taxes that are deducted from rate base,

Unprotected Federal EDIT related to Property, Plant and Equipment

Return excess deferred income taxes related to property, plant and equipment, but not subject to IRS tax normalization rules over 20 years. This proposal would reduce the Company's revenue requirement by approximately $13 million per year. This proposal serves to refund the excess tax amounts over a period that considers the long lives of the property, plant and equipment to which these tax amounts relate. This period aligns with the timeframe that the benefits (i.e., deferred tax liability offset to rate base) would be received by customers absent the change in tax rate. The revenue requirement reduction of $13 million is a net amount that incorporates both the decrease in operating expenses related to the tax rate change and the increase in rate base associated with the lesser amount of accumulated deferred income taxes that are deducted from rate base. DEP's proposal helps to smooth out volatility in customer rates over the long term for the benefit of customers.

Unprotected Federal EDIT – Other

Using a rider, collect over five years the excess deferred taxes related to timing differences between book income and taxable income that are: (1) not subject to IRS normalization rules; and (2) are not related to property, plant, and equipment. For DEP, the deferred income taxes and resulting excess deferred income taxes in this category are a net asset, instead of a net liability. As a result, the balance actually needs to be collected from customers as opposed to returned. The rider would incorporate an approximately $7 million increase in operating expense per year over the five-year period. The increased accumulated deferred income taxes that are deducted from rate base equate to an approximate $2 million reduction in revenue requirements and would be reflected in a base rate adjustment rather than the rider.

DEP noted that the EDIT balances in each category will continue to fluctuate and will not be final until the Company files its 2018 tax returns in late 2019. DEP stated that, therefore, adjustments and true-ups may need to be made in future rate cases.

3. Incorporate an increase in proposed revenue requirements of $100 million to collect certain expenses on an accelerated basis. In doing so, the Company intends to minimize customer rate volatility, and minimize financing costs over the long term.

DEP asserted that the reduction in the federal corporate income tax rate has a dual effect on customer rates – a decrease in operating expense and an increase in rate base. DEP stated that this accelerated return of excess deferred income taxes to customers creates a rate reduction that is followed by a rate increase. DEP maintained that its proposal would smooth out this rate volatility. DEP asserted that this approach does not ask customers to pay costs that are not appropriate costs of providing electric service, but rather adjusts the timing of payment of the costs in a manner that minimizes significant step changes in rates. DEP stated that the amount of accelerated expense recovery proposed by the Company is designed to achieve this objective.

DEP stated that the net effect of the proposed adjustments is a reduction of $56 million in base rates, netted with an annual revenue increase of $7 million through a five-year rider. DEP noted that both DEC and DEP have proposed that the Commission could mitigate these impacts by offsetting items such as storm response costs, ongoing coal ash basin closure compliance costs or other environmental compliance costs, or accelerating the depreciation of certain assets such as the existing AMR meters or coal plants. DEP noted that the accelerated depreciation would be accomplished by creating a North Carolina retail regulatory liability. DEP stated that liability would then be used to reduce depreciation expense on the specific asset or group of assets the next time depreciation rates are updated, similar to the way that the DEP Harris Nuclear Plant accelerated depreciation was used to reduce depreciation expense in Docket No. E-2, Sub 1023.

DEP stated that one option is to use this reduction in the federal corporate income tax rate to offset the ongoing necessary investments in coal ash basin closure expense to comply with the EPA's Coal Combustion Residuals Rule and the North Carolina Coal Ash Management Act. DEP maintained that it would propose to record $100 million amortization expense per year to the same regulatory asset to which the ongoing compliance costs are recorded, thereby reducing customers' future obligation.

DEP noted that another option would be to allow DEP to record $100 million per year for accelerated depreciation for AMR meters and/or certain coal-fired plants. DEP stated that under this option, customers would benefit in the future through lower depreciation expense following the next depreciation study.

DEP noted that this proposed approach would reduce customer bills in the near term and help to offset rate increases in the future. DEP asserted that customers benefit if the Company can maintain its ability to access low-cost capital. DEP stated that this enables the Company to maintain its strong credit quality and any treatment of tax reform should support maintaining the Company's pre-Tax Act credit quality. DEP maintained that its approach will balance the importance of delivering savings to customers and upholding the Company's financial strength, which ultimately benefits customers.

PUBLIC STAFF'S APRIL 3, 2018 LETTER

The Public Staff asserted that the Commission's initial Order in this docket provided utilities and interested parties the opportunity to file initial comments and reply comments. The Public Staff noted that DEP has twice filed supplemental comments in this docket after the Commission's deadline for filing comments has passed. The Public Staff maintained that should the Commission choose to consider DEP's late-filed comments, the Public Staff requests the Commission to reopen the docket in order to allow all parties to file additional comments.

The Public Staff asserted that ratepayers should receive the benefit of the tax reductions from the Tax Act as soon as possible. The Public Staff noted that as requested in the Public Staff's reply comments, the Public Staff requests the Commission to: (1) direct DEP to reduce its rates to reflect any and all cost savings resulting from the reduction in the federal income tax expense component of the cost of providing utility service as soon as practicable; (2) direct DEP to flow back the protected EDIT as soon as practicable in accordance with federal tax normalization rules, and (3) address the unprotected EDIT in the next general rate case filed by DEP.

The Public Staff commented that DEP's supplemental comments recommend that all of the impacts of the Tax Act be addressed in its next general rate case, but DEP provides an alternative proposal should the Commission decide to take action in this docket.

The Public Staff asserted that the issue of the flow back of the unprotected EDIT is more appropriately handled in a general rate case and not in a general rulemaking proceeding. The Public Staff stated that it is also opposed to DEP's proposal to create a false category of unprotected EDIT to delay the flowback of the benefits of the Tax Act to ratepayers over a period of 20 years. The Public Staff maintained that it is also opposed to the proposal to "smooth out rate volatility" by slowing the flowback of benefits to ratepayers by accelerating the depreciation of some unknown assets in the amount of $100 million.

DISCUSSION AND CONCLUSIONS

After reviewing all of the comments, reply comments, and supplemental filings filed in this proceeding and the entire record of evidence, the Commission notes that there are four distinct issues the Commission must decide in this proceeding, as follows:

> <u>Issue No. 1</u> - How should the Commission address the impact of the reduction in the federal corporate income tax rate outlined in the Tax Act for North Carolina public utilities (specifically, the expense piece in base rates and the provisionally collected revenues)?
>
> <u>Issue No. 2</u> - How should the Commission address the EDIT generated due to the reduction in the federal corporate income tax rate outlined in the Tax Act for North Carolina public utilities?
>
> <u>Issue No. 3</u> - How should the Commission proceed in recognition of the fact that CIAC for water and wastewater companies is now subject to federal income taxes based on the Tax Act?
>
> <u>Issue No. 4</u> - How should the Commission address the change in the federal corporate income tax rate in the various riders in effect?

The Commission will now address and resolve each issue separately below.

Issue No. 1 – How should the Commission address the impact of the reduction in the federal corporate income tax rate outlined in the Tax Act for North Carolina public utilities (specifically, the expense piece in base rates and the provisionally collected revenues)?

After reviewing all of the comments, reply comments, and supplemental filings filed and the entire record of evidence, the Commission notes that all of the parties are in agreement that, based on the Nantahala case, the Commission has the authority to adjust base rates in the context of this rulemaking proceeding to reflect the decrease in the federal corporate income tax rate from 35% to 21%. However, the parties disagree on how and when the Commission should address the reduction in the federal corporate income tax rate for North Carolina public utilities.

The following parties recommended that the Commission adjust base rates for the applicable North Carolina public utilities as soon as possible to reflect the reduced federal corporate income tax rate: the Attorney General, CIGFUR, CUCA, the Low-Income Advocates (adjust other rates or use money for other purposes), Nucor (only specifically for DENC), PSNC (although not directly), and the Public Staff. These parties provided the specific recommendations outlined below.

As outlined in greater detail hereinabove, the Attorney General recommended that the Commission exercise its rulemaking authority in this proceeding to order the utilities to flow through these major federal tax reductions to consumers as soon as possible in the form of rate decreases and argued that to the extent that the cost of service effect associated with the lower corporate income tax rate is not flowed through in rates, utilities will continue to over-collect revenues, and customers will continue to be forced to pay excessive rates to build up utility accounts that essentially lend cost-free capital for utility operations.

CIGFUR maintained that the Commission should, as quickly as practicable, pass the substantial and material benefits of the Tax Act onto ratepayers through the most efficient means available, be that through this rulemaking proceeding or through pending general rate cases.

CUCA requested that the Commission, among other things, order the creation of a deferred account to capture all of the changes related to the difference between revenues billed under rates now in effect relative to the attendant cost of service based on the decrease in the federal corporate income tax component from 35% to 21% and an immediate reduction of rates paid by consumers to account for the change in the federal corporate income tax rate from 35% to 21%.

The Low-Income Advocates asserted that excess revenues due to the reduction in the public utilities' cost of service should not accrue to the Companies' shareholders. The Low-Income Advocates also stated that although the Commission has the authority to reduce rates to account for the impact of the tax cut on the public utilities' cost of service, the Commission should not simply order utilities to reduce their rates to account for the entire impact of the tax cut, or to flow all of the over-collections due to the tax cut to their customers in the form of rebates or decrement riders. The Low-Income Advocates maintained that the utilities should be required to invest some portion of the tax savings for the residential class in measures that reduce customer bills such as energy efficient programs for low-income customers. The Low-Income Advocates also argued that the Commission should examine whether it is appropriate to require greater reductions in fixed, monthly charges than in the volumetric rate.

Nucor noted that DENC indicated that it will comprehensively address all impacts from the Tax Act as part of its updated cost of service filed in the Company's next general rate case. Nucor asserted that DENC's proposed approach is inadequate and objectionable. Nucor argued that DENC makes no commitment as to when it will file its next general rate case application[1]. Nucor asserted that the inherent delay in flowing through the federal tax reductions to DENC's customers via a speculative and lengthy general rate case proceeding is unwarranted and would be unfair to DENC's customers. Nucor maintained that the Commission has the authority to address the tax reduction resulting from the Tax Act outside of a general rate case and should do so with respect to DENC. Nucor asserted that the Commission should require that DENC pass through the benefits of the federal tax changes to DENC's ratepayers in a timely manner.

Although PSNC did not make a clear statement that public utility base rates should be adjusted now to reflect the decrease in the federal corporate income tax rate, the Company did propose to adjust its rates by allocating the annual revenue requirement impact of the Tax Act changes to the various rate schedules based on the volumes determined in PSNC's most recent general rate case, Docket No. G-5, Sub 565. PSNC stated that the change in rates applicable to each rate schedule would be used to determine the appropriate level of deferred revenue to record per ordering paragraph two of the January 3, 2018 Order. PSNC asserted that due to the administrative burden of implementing a refund by recalculating previously issued bills, PSNC would propose to refund provisionally collected amounts by moving the balance in the regulatory liability account to the Company's All Customers Deferred Account. PSNC noted that this is the same treatment that PSNC used to refund provisionally collected amounts in Docket No. M-100, Sub 138 (the State corporate income tax change generic proceeding).

The Public Staff stated that it believes it is permissible for the Commission to address the effects of the Tax Act through this docket. The Public Staff maintained that the Tax Act will result in a significant reduction in the federal corporate income taxes paid by most, if not all, utilities regulated by the Commission. The Public Staff further noted that this reduction will, in turn, result in a reduction in the cost of providing public utility services to North Carolina customers, which the Public Staff believes is sufficiently substantial and material to justify an exception to the doctrine against single-issue ratemaking. The Public Staff recommended that the Commission direct the subject utilities to reduce their rates to reflect any and all cost savings resulting from the reduction in the federal income tax expense component of the cost of providing utility service as soon as practicable.

The Public Staff also recommended that the Commission direct the subject utilities to refund the amount collected in the deferred account established by the Commission in this proceeding that represents the difference between revenues billed under the prior federal income tax rate and the federal income tax rate resulting from the Tax Act starting January 1, 2018.

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[1] In its reply comments, DENC committed to filing a single-issue adjustment to its base rate cost of service on or before June 30, 2019 if the Company has not filed a general rate case as of that date.

The Public Staff stated that arguments raised by the subject utilities related to cost of capital and cash flow should not be addressed in this docket. The Public Staff argued that absent compelling evidence of financial harm to the utilities, the ratepayers should receive the benefit of the tax reductions from the Tax Act as soon as possible. The Public Staff asserted that cost of capital is appropriately addressed in a general rate case. The Public Staff maintained that if a subject utility believes its cost of capital has changed and earnings are insufficient to achieve the new cost of capital, it should file a general rate case to address this issue.

Finally, the Public Staff stated that to implement the recommendations outlined in its reply comments, the Public Staff requested that the Commission direct the subject utilities to file with the Commission and the Public Staff rate reductions to address the changes by March 30, 2018. The Public Staff stated that the subject utilities should also be required to file workpapers with the Commission and the Public Staff to support the rate reduction calculations. The Public Staff maintained that once rates are established, the subject utilities should continue to file quarterly reports on the status of their EDIT deferred account, and the deferral account established under this proceeding that represents the difference between revenues billed under the prior federal income tax rate and the federal income tax rate resulting from the Tax Act starting January 1, 2018.

CWSNC, DEC/DEP, DENC, and Piedmont recommended that base rates not be reduced as soon as possible to reflect the reduced federal corporate income tax rate. The Companies made the following specific recommendations as outlined below.

CWSNC noted that its current utility rates were set based upon rate base and operating expense levels, along with the federal corporate income tax rate of 35%, which were in place at the time of the Company's last rate case in 2017[1]. CWSNC stated that the impact upon utility rates cannot be analyzed by only looking at the impact due to the change in just one component of the Company's revenue requirement. CWSNC stated that if the true impact is going to be analyzed for the change in the federal corporate income tax rate, then all other components of the Company's revenue requirement calculation need to be taken into consideration because it is likely that those other components have changed since the rates were last set by the Commission.

DEC/DEP asserted that implementation of the Tax Act has the potential to adversely affect the Companies' cash flows needed to fund ongoing operations and new infrastructure investments, and makes having a strong equity to debt capital structure even more important post-Tax Act reform. DEC/DEP stated that an unmitigated cash flow shortfall could force the Companies to rely excessively on third-party capital to fund DEP and DEC, to the ultimate detriment of their financial condition.

DEC/DEP noted that with respect to DEC, the Company proposes to address federal tax reform impacts in its pending rate case in Docket No. E-7, Sub 1146, for which the evidentiary hearing is currently scheduled to begin on February 27, 2018[2]. DEC/DEP noted that with respect

[1] The Commission notes that CWSNC filed a 30-day notice of intent to file a general rate case application on March 23, 2018, in Docket No. W-354, Sub 360. CWSNC filed its general rate case application on April 27, 2018.

[2] The evidentiary hearing was subsequently changed to begin on March 5, 2018. The Commission issued its Order in DEC's rate case proceeding on June 22, 2018.

to DEP, the Company also has a pending rate case in Docket No. E-2, Sub 1142, however the record in that case has closed, and DEP anticipates that the Commission will issue a final order in the near term[1]. DEC/DEP stated that once the Commission order in that rate case proceeding is received, DEP will be able to calculate the impacts of the Tax Act on tax expense based on a compliance cost of service with the Commission's order. DEP proposed to defer the resulting estimated impacts to a regulatory liability, until DEP's next rate case. DEC/DEP maintained that as an alternative, the Commission could approve a rider in Docket No. M-100, Sub 148 to reduce DEP customer rates including any potential offsets.

DEC/DEP noted that in DEP's rate case proceeding, DEP proposed to apply the decrement to North Carolina retail services beginning January 1, 2018, and defer the resulting amount into a regulatory liability until new rates can be established in its next general rate case, or in the alternative to reduce rates in a rider to be established by the Commission in this generic docket. DEC/DEP proposed options to help mitigate future rate increases by applying the federal income tax expense savings to offset items such as storm response costs, ongoing coal ash basin closure compliance costs or other environmental compliance costs, or accelerating the depreciation of certain assets such as the existing AMR meters or coal plants. DEC/DEP asserted that nothing in the intervenors' initial comments changes the Companies' recommendation that the Commission should implement a balanced solution to ensure that customers receive the benefits of tax reform.

DENC maintained that for purposes of the Company's base non-fuel rates and Rider EDIT, the Company intends to address the cost of service impacts and disposition of deferred amounts due to the Tax Act through the Commission's general ratemaking procedure set forth in N.C. Gen. Stat. § 62-130 and N.C. Gen. Stat. § 62-133. DENC stated that this approach ensures that the Company has sufficient time to comprehensively evaluate the direct and indirect impacts of this complex new tax legislation in determining the Company's updated cost of service. DENC asserted that the differences between rates in effect at January 1, 2018, including provisional components, and revenues that would have been billed incorporating the IRC as now amended by the Tax Act, will be held in a deferred account. DENC argued that this approach is reasonable and fair to customers and the Company, as the Company is now collecting these amounts on a provisional basis.

DENC maintained that it recognizes the Public Staff's and other parties' objective of ensuring that provisionally-collected amounts are expeditiously recognized in the Company's utility rates. However, DENC asserted that efficiencies would be achieved by comprehensively addressing all federal income tax issues in the Company's next general rate case. DENC stated that to balance these interests, the Company commits to filing a single-issue adjustment to its base rate cost of service on or before June 30, 2019, if the Company has not filed a general rate case as of that date.

DENC opined that provisional recovery and deferral accounting combined with its commitment to file a single-issue proceeding to address these impacts by June 30, 2019, if it has not yet filed a base rate case, appropriately balances the desire to expeditiously pass the benefits of the Tax Act to ratepayers with the Company's approach to efficiently adjusting its rates and

[1] The Commission issued its Order in DEP's rate case proceeding on February 23, 2018.

charges to comprehensively address all base rate cost of service impacts resulting from the Tax Act. DENC maintained that if the Commission determines that it is appropriate to reduce utility rates through a rulemaking procedure on a more accelerated schedule, the Company recommends that the Commission only order DENC to adjust the income tax expense portion of operating income in the Company's cost of service and leave the other elements of the tax changes enacted in the Tax Act for review in the Company's next general rate case. DENC stated that, in any case, it stands ready to work with the Public Staff and to take whatever action the Commission directs to provide the benefits of the Tax Act to the Company's customers.

Piedmont stated that it is proposing to reduce customer bills through the flow-through of tax rate reductions under its Integrity Management Rider mechanism while deferring tax rate reductions on its base rates until the next general rate case proceeding where such deferral can be amortized and used to offset any requested base rate increase in that docket.

Piedmont asserted that while some intervenors request that the Commission reduce customer rates and the utilities' revenues immediately to account for 100% of the impacts of the Tax Act, Piedmont submits that its proposals represent a more balanced approach. Piedmont maintained that customers receive an immediate benefit in the form of savings under the Tax Act through rate reductions commencing with its upcoming June 1, 2018 IMR rate adjustment, but that tax rate reductions on its base rates be deferred until its next general rate case proceeding.

The Commission, having thoroughly reviewed and considered all of the filings made in this proceeding, concludes that it is appropriate to require an immediate reduction in the base rates (for the expense piece) of affected utilities to reflect the 21% federal corporate income tax rate mandated by the Tax Act, effective January 1, 2018. The Commission finds that the federal corporate income tax rate reduction mandated by the Tax Act is material and substantial, a fact that no party disputes, and that ratepayers should not be forced to continue paying base rates that were set to recover a 35% federal corporate income tax rate that has been reduced to 21% until the utility's next general rate case proceeding.

The Commission also agrees with all of the parties that based on the Nantahala decision from the 1986 federal Tax Act, the Commission does have the authority to require this flow-through in this rulemaking proceeding. The Commission does not find the comments made by most of the utilities recommending that flow-throughs for the expense adjustment be delayed until the next general rate case proceeding of each utility to be convincing or persuasive. The Commission concludes that the ratepayers should receive the benefit of the tax reductions from the Tax Act as a reduction to expense and therefore a base rate decrease as soon as possible. Although an immediate flow through of the expense piece will decrease the cash flow of utilities, the Commission finds that its decision herein on the EDIT generated due to the Tax Act (See Issue No. 2 below) will mitigate any adverse effects from this cash flow decrease.

As further discussed below, the Commission will address this issue in the context of Aqua's and CWSNC's pending rate case proceedings. The Commission did require DEC to flow through the 21% federal income tax rate in expenses in DEC's most recent rate case proceeding (Docket No. E-7, Sub 1146) in the Commission's June 22, 2018 Order.

Finally, the Commission notes that Cardinal filed a notice of intervention in this docket, and its intervention was granted by the Commission. However, Cardinal did not file initial and/or reply comments, and no other party specifically mentioned Cardinal in its initial or reply comments. The Commission notes that Cardinal was required to flow through the decrease in the State corporate income tax rate under HB 998 in the context of Docket No. M-100, Sub 138. Further, the Commission notes that in Cardinal's last general rate case proceeding, Docket No. G-39, Sub 38, the Commission issued an Order Decreasing Rates on July 27, 2017. Finding of Fact No. 13 of that Order stated that the federal corporate income tax rate of 35% was reasonable and appropriate for use in determining Cardinal's federal income taxes in the docket. Therefore, the Commission concludes that in the context of this docket Cardinal shall also be required to flow through the decrease in the federal corporate income tax rate in its rates.

The Commission also concludes that it is appropriate to find that the Companies shall continue to hold in a deferred regulatory liability account the difference between revenues billed under the prior federal corporate income tax rate and the federal corporate income tax rate resulting from the Tax Act starting January 1, 2018 as previously ordered in the Commission's January 3, 2018 Order and the disposition of such regulatory liability will be considered in each utility's next general rate case proceeding or in three years, whichever is sooner. DEC is included in this decision because the issue of how to handle the provisional amounts collected since January 1, 2018 based on rates reflecting the 35% federal corporate income tax rate was not addressed in DEC's recent rate case proceeding. These amounts will ultimately be returned to customers with interest reflected at the overall weighted cost of capital approved in each Company's last general rate case proceeding.

Based on the foregoing conclusions, Cardinal, DENC, DEP, Piedmont and PSNC[1] should file rate reduction proposals to reflect the change in the federal corporate income tax rate by Thursday, October 25, 2018. The rate reduction proposals should include all workpapers that support the proposed rate reduction calculations. The Public Staff is specifically requested to file comments on the proposals by no later than Wednesday, November 14, 2018. Other parties also may file comments on the proposals by no later than Wednesday, November 14, 2018.

The Commission is opening new Company-specific dockets that will be used for all filings related to the implementation of this Order, as follows:

[1] On February 1, 2018, in Docket Nos. M-100, Sub 138 and G-5, Sub 565, PSNC filed an Application to Refund Overcollection. PSNC noted that in the course of preparing the Commission requested comments in this docket, PSNC determined that the previously submitted revenue requirement reduction associated with the decrease in the state corporate income tax rate from 4% to 3% was calculated incorrectly. PSNC maintained that incremental amounts currently being collected in rates due to the error in determining the revenue requirement decrease associated with the State corporate income tax rate reduction to 3% will be incorporated into the determination of provisional amounts being collected as a result of the federal corporate income tax rate reduction from 35% to 21%. On February 8, 2018, PSNC filed a letter noting that it had determined the additional amounts collected from customers that need to be refunded. On March 28, 2018, the Public Staff filed a letter stating that it has reviewed PSNC's filings and recommended that the Company file to reduce its margin rates to reflect this additional reduction in its revenue requirement. The Commission finds that PSNC's rate reduction proposal filed as requested herein should also include the required correction to rates to reflect the 3% State corporate income tax rate.

DEC	Docket No. E-7, Sub 1184
DEP	Docket No. E-2, Sub 1188
DENC	Docket No. E-22, Sub 560
Piedmont	Docket No. G-9, Sub 731
PSNC	Docket No. G-5, Sub 595
Cardinal	Docket No. G-39, Sub 42

Further, once rates are established, the subject utilities should file quarterly reports in the appropriate newly-created, Company-specific docket, due no later than 30 days after the end of a quarter, on the status of their EDIT deferred account, and the deferral account established under this proceeding that represents the difference between revenues billed under the prior federal corporate income tax rate and the federal corporate income tax rate resulting from the Tax Act starting January 1, 2018. DEC shall also be required within the context of this Order in this proceeding to file the quarterly reports.

<u>Public Utilities with Unique Circumstances</u>

<u>Aqua</u> filed an application for a general rate case on March 7, 2018 in Docket No. W- 218, Sub 497. Aqua proposes that the Commission address the Tax Act in Aqua's currently pending rate case docket, and the Public Staff has agreed with that recommendation. Therefore, the Commission finds it appropriate to address the impact of the Tax Act on Aqua in Docket No. W-218, Sub 497. Consequently, the Commission will not address Aqua further in this generic rulemaking proceeding.

<u>CWSNC</u> filed a 30-day notice of intent to file an application for a general rate case on March 23, 2018 in Docket No. W- 354, Sub 360. CWSNC filed its general rate case application on April 27, 2018.

On April 6, 2018, CWSNC filed a Procedural Request. CWSNC noted that it intends to file a general rate case application on April 23, 2018, and now proposes that the impact of the Tax Act on the Company's rates be addressed and resolved in that proceeding (Docket No. W-354, Sub 360). CWSNC maintained that it was authorized to state that the Public Staff supports the procedural request, subject to the proviso that the Company in fact files its general rate case application on April 23, 2018, or a date soon thereafter.

Based on the foregoing, the Commission finds it appropriate to address the impact of the Tax Act on CWSNC in Docket No. W-354, Sub 360. Consequently, the Commission will not address CWSNC further in this generic rulemaking proceeding.

<u>DEC</u> has had a recent rate case proceeding, Docket No. E-7, Sub 1146. The changes as a result of the Tax Act were addressed in that rate case proceeding by Orders dated June 22, 2018 and July 2, 2018. Therefore, the Commission will not address the expense piece for DEC further in this generic rulemaking proceeding.

<u>Frontier</u> noted that in the Commission's 2013 proceeding addressing the decrease in the State corporate income tax rate (Docket No. M-100, Sub 138), the Public Staff acknowledged that

Frontier provides gas service pursuant to rates established in connection with the granting of its certificate, not rates established in a general rate case based on specific items of cost. Frontier also noted that, therefore, the Public Staff recommended that the Commission not adjust Frontier's rates as a result of HB 998 (the State legislation decreasing the State corporate income tax rate). Frontier maintained that the Commission agreed with the Public Staff and found it appropriate to exclude Frontier from further consideration by the Commission in that docket. Frontier stated that the Commission's ruling effectively exempted Frontier from any obligation to flow-through the State corporate income tax reductions adopted in HB 998 on the grounds that its rates were not cost-based in the first instance, therefore, it made little sense to compel the adoption of a cost-based adjustment to those rates. Frontier argued that the same logic would compel a similar result in this docket.

The Public Staff stated in its reply comments, which were subsequently clarified by the Public Staff, that Frontier has been collecting funds from its ratepayers in order to pay Frontier's federal income tax obligations. The Public Staff further stated that the Tax Act reduces the federal tax obligations of Frontier and that its ratepayers should benefit from the reduction in the federal corporate income tax resulting from the Tax Act. Accordingly, the Public Staff originally recommended that Frontier be subject to the provisions of this docket.

The Public Staff maintained in its Clarification to Reply Comments that in Docket No. G-40, Sub 136, by Order dated August 1, 2017, the Commission approved a merger between Frontier and FR Bison Holdings, Inc., subject to certain regulatory conditions. The Public Staff noted that Regulatory Condition #10, provided that the Public Staff would not request a change in Frontier's margin rates unless certain exceptions apply. The Public Staff stated that the Regulatory Condition in its entirety reads:

> "**Rate Case Moratorium.** Neither Frontier nor the Public Staff will request a change in Frontier's margin rates until after December 31, 2021, except as set forth below. For purposes of this provision, the margin rate is defined as the tariff rate less the benchmark cost of gas and temporary increments and/or decrements imposed pursuant to G.S. 62-133.4 or Commission Rule R1-17(k). The exceptions to the moratorium imposed by this Condition are as follows: (a) Should Frontier or the Public Staff believe that Frontier should implement a pipeline safety rate adjustment mechanism pursuant to G.S. 62-133.7A, either party shall have the right to apply to or petition the Commission to initiate a general rate case proceeding; and (b) effective July 1, 2019, should Frontier's rolling twelve-month earned return on average rate base, based on a reasonable pro forma capital structure and reasonable regulatory adjustments, exceed 12.00% for two quarters in any consecutive four-quarter period, the Public Staff shall have the right, after notice to and consultation with Frontier's management, to petition the Commission to initiate a general rate case proceeding."

The Public Staff asserted that, consistent with the Regulatory Condition, the Public Staff seeks to clarify that in its comments submitted on February 20, 2018, the Public Staff is not requesting the Commission to change Frontier's margin rates. The Public Staff stated that it recognizes that the Commission is not bound by the Public Staff's agreement with Frontier with respect to any change in margin rates and may find in its discretion that Frontier should be directed to reduce its rates to reflect the changes in the Tax Act. The Public Staff stated that, notwithstanding the foregoing, the Public Staff does request that Frontier be subject to any reporting requirements adopted in this docket.

The Commission notes that the Public Staff did not provide any reasoning behind its differing positions in the State generic tax docket (Docket No. M-100, Sub 138) and this federal generic tax docket on how Frontier should be treated by the Commission. The Public Staff recommended, and the Commission agreed with and approved the recommendation, that the decrease in the State corporate income tax rate as a result of HB 998 should not be flowed through for Frontier because Frontier's rates were established in connection with the granting of its certificate and not in a general rate case proceeding based on specific items of cost. Further, in this proceeding, ultimately, based on Regulatory Condition #10 of the 2017 merger with FR Bison Holdings, Inc., the Public Staff recommended that the Commission not change Frontier's margin rates.

Based upon the following, the Commission concludes that it is appropriate to exclude Frontier from further consideration by the Commission in this proceeding. The Commission concludes that Frontier's rates were established in a very different manner than a rate case proceeding wherein specific items of cost are included in setting the rate to be charged by the utility. Therefore, the Commission does not believe Frontier's rates can or should be adjusted to reflect the decrease in the federal corporate income tax rate. The Commission notes that this conclusion is consistent with the Commission's conclusions in the State corporate income tax rate rulemaking proceeding, Docket No. M-100, Sub 138. The Commission urges the Public Staff to enforce Regulatory Condition #10 of the 2017 merger if Frontier's earned return exceeds 12.00% for two quarters in any consecutive four-quarter period.

<u>Toccoa</u> filed its comments noting that it is a municipally-owned natural gas system that is not subject to income or other tax obligations. Toccoa also noted that the Commission found it appropriate in Docket No. M-100, Sub 138 addressing House Bill 998 (implementing the State corporate income tax rate reduction) to exclude Toccoa. The Public Staff filed comments agreeing with Toccoa's comments in this regard.

Based upon the following, the Commission concludes that it is appropriate to exclude Toccoa from further consideration by the Commission in this proceeding because Toccoa is not subject to income or other tax obligations and, therefore, no tax allowances were included in any determination of Toccoa's revenue requirements when the Commission established its rates.

<u>Issue No. 2</u> – How should the Commission address the EDIT generated due to the reduction in the federal corporate income tax rate outlined in the Tax Act for North Carolina public utilities?

After reviewing all of the comments, reply comments, and supplemental filings filed and the entire record of evidence, the Commission notes that all of the parties that provided specific comments on the issue of EDIT agreed that there is protected and unprotected EDIT based on the Tax Act. Protected EDIT requires flow-back based on IRS normalization rules while unprotected EDIT is not constrained by IRS normalization rules.

The following parties recommend that the Commission require some or all of the EDIT to be flowed back or returned to customers as soon as possible: Attorney General; CIGFUR (using a two or three year decrement rider); Low-Income Advocates (with at least 25% applied toward low-income efficiency programs); and the Public Staff (protected EDIT flowed back as soon as possible with normalization rules; unprotected EDIT flowed back in each utility's next general rate case unless there is a currently-pending rate case). These parties provided the specific recommendations outlined below.

The Attorney General noted that DEC/DEP do not identify how much the Companies hold in accounts for ADIT, do not report the EDIT amount that they have accrued based on the reduction in federal income taxes, and do not propose to return any of the EDIT amounts to ratepayers until they file future general rate cases. The Attorney General maintained that instead, DEC/DEP propose to hold onto those excess funds, apparently for several years, as cost-free capital.

The Attorney General observed that other utilities also suggest limiting or deferring the benefit of income tax reform rather than flowing it through to ratepayers promptly. The Attorney General noted that DENC proposed to hold onto the excess amount that has accrued in deferred income taxes for consideration in its next general rate case. The Attorney General noted that CWSNC made a similar proposal, and that Piedmont proposed to defer the benefits of tax reform for consideration in a future general rate case. The Attorney General specified that, like DEC/DEP, Piedmont did not reveal the current balances of ADIT and EDIT deferred tax accounts.

The Attorney General argued that allowing utilities to hold onto the excess is particularly unreasonable if the utility has a pending general rate case or if rates were recently established. The Attorney General stated that DEC has acknowledged that it is appropriate to address the effect of tax reform in the pending DEC general rate case, but suggests that it is not appropriate to address tax reform in the pending DEP case because the evidentiary hearing has already been held in that case. The Attorney General asserted, however, that the fact that the evidentiary hearing has already occurred in the DEP case should not postpone action until another rate case is filed years from now.

The Attorney General maintained that as a result of the scant information provided by the utilities in their initial comments, the public and the Commission do not know how much EDIT have been accrued. The Attorney General argued that, however, this information is known to the utilities because publicly-traded utilities must report this data in their annual reports to shareholders, and the information should be reported and considered in this docket as well. The Attorney General maintained that the amount of EDIT may be very large. The Attorney General further noted that according to an estimate provided in comments filed by CUCA, based on FERC Form 1 filings, Duke Carolinas has over $1.6 billion of excess accrued deferred income taxes allocated to North Carolina retail customers, and Duke Progress has approximately $875 million.

The Attorney General stated that, similarly, if the utilities' proposals are accepted and they are allowed to retain the funds they are currently holding in EDIT accounts, i.e., excess deferred income taxes that were collected in earlier years when the federal income tax rate was higher than it is following the Tax Act, then the utilities would continue to maintain these excess funds as cost-free capital. The Attorney General argued that not returning dollars to consumers who struggle to pay their bills, or to consumers who would use their money for different purposes if given the opportunity, results in an undue burden on ratepayers and communities in North Carolina.

The Attorney General requested that the Commission take prompt action to require the utilities to provide a full accounting of the past and present extent of over-collection of taxes and then to order immediate utility rate reductions that return excess deferred income taxes that have accrued as soon as allowed under federal tax law.

CIGFUR maintained that EDIT should be refunded to ratepayers through a decrement rider as soon as practicable. CIGFUR asserted that due to the Tax Act, DENC's, DEP's, and DEC's future tax liabilities will not be as high as anticipated when rates were originally designed. CIGFUR stated that the amount by which DENC's, DEP's, and DEC's current ADIT balances exceeds their future income tax liability as a result of the Tax Act are the EDIT at issue. CIGFUR noted that further, until the Commission adjusts utility rates to reflect the new lower tax rate, the utilities will continue to collect excess income tax from ratepayers at the 35% tax rate, which the Commission approved for DENC, DEP, and DEC in Docket Nos. E-22, Sub 532, E-2, Sub 1023, and E-7, Sub 1026, respectively.

CIGFUR asserted that these EDIT should be promptly flowed back to ratepayers; however, DENC, DEP, and DEC argue against returning EDIT to ratepayers in a timely manner and instead propose to defer their EDIT as regulatory liabilities until their next general rate cases. CIGFUR stated that it opposes long-term deferral of EDIT and proposes that, concurrent with the immediate rate reductions discussed in its reply comments, the Commission establish a decrement rider for each utility to refund EDIT to ratepayers over a two or three year period.

The Low-Income Advocates recommended that the Commission order a portion of the previously over-collected taxes, or EDIT, to flow back to ratepayers in the form of investments in low-income efficiency programs. The Low-Income Advocates asserted that the accumulated deferred income taxes have already been collected from customers, and given the change in the federal corporate income tax rate enacted by Congress, have been over-collected. The Low-Income Advocates stated that this excess is now a regulatory liability that should be returned to customers. The Low-Income Advocates noted that consistent with the requirements for the normalization method of accounting for deferred taxes for regulated public utilities, the public utilities in this docket should return the difference between the deferred income taxes accounted for under the higher federal corporate income tax rate under prior law and the lower rate that was recently established in the Tax Act. The Low-Income Advocates asserted that a portion of the EDIT should be returned to ratepayers in the form of direct investments in low-income energy efficiency. The Low-Income Advocates noted that based on the initial comments filed it is not clear what the total change in the EDIT will be over the next several years, or how fast the utilities can return the over-collected deferred income taxes to ratepayers under normalization rules. The Low-Income Advocates stated that at a minimum, it would be reasonable for the public utilities to invest at least 25% of EDIT for low-income efficiency.

The Public Staff maintained that, as in Docket Nos. M-100, Sub 113 and M-100, Sub 138, the Commission should require that the EDIT resulting from the decrease in the federal corporate income tax rate established in the Tax Act be flowed back to the ratepayers. The Public Staff asserted that the treatment of EDIT in those dockets should provide a framework for the treatment of EDIT created by the Tax Act.

The Public Staff stated that the Tax Act provides that certain EDIT should be flowed back to the ratepayers subject to certain limitations. The Public Staff specified that the EDIT subject to these limitations is generally referred to as the "protected EDIT." The Public Staff noted that the EDIT that is not subject to limitations in the timing of flow back is generally referred to as the "unprotected EDIT."

The Public Staff asserted that the protected EDIT should be flowed back as soon as practicable in accordance with federal tax normalization rules. The Public Staff stated that compliance with federal tax normalization rules slows the return of the protected EDIT to ratepayers as compared to what regulators might otherwise desire. The Public Staff stated that it does not recommend delaying the return of the protected EDIT or in any way further slowing the return of the protected EDIT to ratepayers, other than the delay required under federal law.

The Public Staff further recommended that the flow back of the unprotected EDIT should be addressed in the next general rate case filed by each of the subject utilities, except for those with currently pending general rate cases.

Finally, the Public Staff recommended that the Commission direct the subject utilities to file with the Commission and the Public Staff rate reductions to address the changes by March 30, 2018. The Public Staff maintained that once rates are established, the subject utilities should continue to file quarterly reports on the status of their EDIT deferred account, and the deferral account established under this proceeding that represents the difference between revenues billed under the prior federal income tax rate and the federal income tax rate resulting from the Tax Act starting January 1, 2018.

The following parties recommend that the Commission address EDIT in each utility's next general rate case: Aqua (and a rate case was filed on March 7, 2018); CUCA (for current DEP and DEC rate cases; otherwise create regulatory liability to address change in EDIT); CWSNC, DENC; DEP (since the current rate case docket is now closed); Piedmont; and PSNC. These parties provided the specific recommendations outlined below.

Aqua proposed to account for the federal EDIT by reducing the deferred taxes ratably over the regulatory life of the underlying property. Aqua stated that it intends to defer the process of amortizing these EDIT until they are addressed in the upcoming rate case filing (that was subsequently filed on March 7, 2018, in Docket No. W-218, Sub 497).

CUCA noted that it recognizes that the Commission has previously addressed the issue of EDIT in Docket No. M-100, Sub 138. CUCA stated that the Commission, in that docket, required the establishment of a regulatory liability account for the EDIT that would be addressed in the next rate case for each of the Companies. CUCA stated that it has estimated the issue of EDIT to be approximately $875 million for DEP and over $1.6 billion for DEC. CUCA stated that it estimated these amounts based upon values found in the FERC Form 1 reports of DEP and DEC allocated to the North Carolina retail consumer and from Form E-1, item 45A of the ongoing DEP and DEC rate cases. CUCA stated that given the fact that DEC and DEP have pending rate cases before the

Commission, CUCA requested that the Commission address the issue of EDIT in these ongoing cases.

CWSNC stated that with respect to EDIT, although exact figures will not be available to the Company for at least 60 days, CWSNC has been collaborating with external tax professionals to assess the impact of the excess ADIT due to the change in the federal corporate income tax rate. CWSNC noted that its proposed accounting treatment of the issue is described in Exhibit 2 attached to its initial comments. CWSNC stated that the protected and non-protected EDIT computed will remain in a regulatory liability account and will not be amortized until the Company is further instructed by the Commission during the next general rate case proceeding[1].

DEC made specific proposals for the treatment of EDIT in its current rate case proceeding. DEP proposed that EDIT be placed in a regulatory liability account and addressed in its next general rate case proceeding. Both DEC and DEP noted that, in addition, all EDIT amounts are by necessity estimated, pending completion of the Companies' federal corporate income tax returns in 2019 for tax year 2018.

DENC maintained that it reduced the balance of ADIT in its financial records to reflect an estimated amount of EDIT for the Virginia Electric and Power Company system effective December 31, 2017. DENC stated that, however, such estimate and the portion allocable to the North Carolina retail operations will be further refined throughout the coming year as a more detailed analysis is completed and needed guidance from the IRS is forthcoming.

DENC asserted that in accordance with Generally Accepted Accounting Principles (GAAP), the Company recorded in its financial records a reduction in the balance of EDIT effective December 31, 2017, to reflect an estimate of the impact of the Tax Act. DENC stated that the reductions in ADIT associated with the Company's regulated operations and recognized for ratemaking purposes were reclassified to regulatory liability accounts. DENC stated that the predominant portion of EDIT is subject to the IRC's normalization rules. DENC maintained that certain tax technical issues have yet to be resolved and additional guidance from the IRS is expected. DENC argued that addressing the ratemaking treatment of EDIT in the Company's next general rate case rather than through rulemaking allows for additional time to resolve these issues to ensure that the Company's rates and charges are maintained in accordance with the IRC's normalization rules.

Piedmont argued that the flow back of EDIT should not be automatic, rather the Commission should consider all matters that could affect rates. Piedmont stated that the Tax Act represents a unique opportunity to deliver savings to customers, but as with all ratemaking actions, the long term and short term interests of customers must be balanced.

Piedmont maintained that for EDIT, the Company will establish a regulatory liability and, similar to the Commission's treatment of EDIT in Docket No. M-100, Sub 138, would propose that those liabilities be addressed in the Company's next general rate case proceeding. Piedmont

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[1] The Commission notes that CWSNC filed a 30-day notice of intent to file a general rate case application on March 23, 2018, in Docket No. W-354, Sub 360. CWSNC filed its general rate case application on April 27, 2018.

also noted that a significant portion of the EDIT resulting from the federal income tax rate change will be subject to normalization restrictions.

PSNC stated that the reduction in the federal corporate income tax rate from 35% to 21% will result in EDIT. PSNC stated that it proposes, and requests Commission approval, to record the adjustment to deferred taxes as a regulatory liability that will result in no net change in rate base until amortization of the liability begins. PSNC maintained that in accordance with Financial Accounting Standards Board requirements, the adjustments to deferred taxes will be grossed up to a pre-tax amount when recorded in a regulatory liability. PSNC noted that it proposes that the amortization of the regulatory liability be addressed in PSNC's next general rate case.

The Commission notes that in the generic rulemaking proceeding established by the Commission to address the recent changes in the State corporate income tax rate (Docket No. M-100, Sub 138), the Commission concluded that EDIT for all utilities, as appropriate, were to be held in a deferred tax regulatory liability account until they could be amortized as reductions to income tax expense for ratemaking purposes in each utility's next general rate case proceeding. The Commission stated that it agreed with PSNC Energy's comments in that docket that recognizing the amortization of the EDIT in the next general rate case of a utility would provide for certainty as to the amount to be amortized instead of having to base the flow-back calculation on an estimate. In that proceeding, no party objected to that option of handling the EDIT. And the Commission notes that that process has worked well and customers received or are receiving EDIT related to the State corporate income tax rate changes.

Further, the Commission notes that in the Commission's 1986 federal corporate income tax law change generic rulemaking proceeding (Docket No. M-100, Sub 113), the Commission concluded in its October 20, 1987 Order to Require Filing of Tariffs to Reduce Rates and Refund Plans to Effect Flow Through of Tax Savings for Those Regulated Companies not covered by Specific Orders on This Matter, as follows: "[t]hat the appropriate amortization of accumulated excess deferred income taxes will be considered in each company's next general rate case or such other proceeding as the Commission may determine to be appropriate. Any additional amounts relating to the adjustment that should have been made by the company for the flow back of excess deferred income taxes shall be placed in a deferred account and should ultimately be refunded to ratepayers with interest."

In this current proceeding, DEC and DEP noted that all EDIT amounts are by necessity estimated, pending completion of each Company's federal income tax return in 2019 for tax year 2018, and DENC stated that its EDIT estimated amount would be further refined throughout 2018 as more detailed analysis is completed and needed guidance from the IRS is forthcoming.

In addition, the Commission finds, based on the comments filed, that it is appropriate to minimize the rate volatility that could occur with implementing all of the impacts of the Tax Act immediately. Therefore, the Commission concludes that the appropriate balancing includes a base rate adjustment now for the expense piece as discussed above in Issue No. 1 and a reasonable delay, with interest, in the adjustments required to reflect the EDIT generated due to the Tax Act.

Further, the Commission concludes, based on the concerns expressed by DEC, DEP, and Piedmont, that a reasonable delay in the return of the EDIT will help minimize any potential unfavorable credit quality impacts of the Tax Act on the utilities.

Therefore, based on the precedent set in both Docket No. M-100, Sub 113, which precedent includes a review and opinion by the North Carolina Supreme Court in Nantahala, and Docket No. M-100, Sub 138, and the current uncertainty of the ultimate EDIT balances due to the Tax Act, and in an effort to minimize rate volatility and potential adverse credit quality impacts, the Commission finds that it is reasonable and appropriate to address the ratemaking treatment of EDIT in each utility's next general rate case proceeding or three years from the date of this Order, whichever is sooner. The Commission further finds that the EDIT shall be returned to customers with interest reflected at the overall weighted cost of capital approved in each Company's last general rate case proceeding. Thus, EDIT for Cardinal, DENC, DEP, Piedmont, and PSNC shall continue to be held in a regulatory liability account until each Company's next general rate case proceeding or for three years, whichever is sooner, and should ultimately be refunded to ratepayers with interest. Based on this decision, the utilities do not maintain EDIT as cost-free capital as asserted by the Attorney General. Further, EDIT for Aqua and CWSNC will be addressed in each Company's currently pending rate case proceeding (Docket No. W-218, Sub 497 for Aqua and Docket No. W-354, Sub 360 for CWSNC). EDIT for DEC was addressed by the Commission's June 22, 2018 and July 2, 2018 Orders in DEC's rate case proceeding (Docket No. E-7, Sub 1146).

Finally, the Commission finds it appropriate, once rates are established, to require the affected utilities to file quarterly reports in the appropriate newly-established, Company-specific docket, due no later than 30 days after the end of a quarter, on the status of their EDIT deferred account, and the deferral account established under this proceeding that represents the difference between revenues billed under the prior federal corporate income tax rate and the federal corporate income tax rate resulting from the Tax Act starting January 1, 2018. DEC shall also be required within the context of this Order in this docket to file the quarterly reports.

Issue No. 3 – How should the Commission proceed in recognition of the fact that CIAC for water and wastewater companies is now subject to federal income taxes based on the Tax Act?

CWSNC recommended that the Commission consider the impact of the Tax Act upon CIAC. CWSNC noted that the Tax Act removes the tax exemption for CIAC and thus, effective January 1, 2018, water and wastewater utilities like CWSNC will have to begin paying income taxes on cash and property CIAC they receive. CWSNC argued that this change will negatively affect CWSNC's opportunity to earn a reasonable return on its property used and useful in public service if the Company is not allowed to collect the appropriate tax on the CIAC received. CWSNC noted that it will immediately seek to collect from developers (and others) who transfer property and cash to the Company as CIAC based upon the new treatment under the Tax Act; however, there may be some amounts that are not collected as a result of the timing of the tax reform change. CWSNC also noted that it does not believe that collection of this tax resulting from a change in the federal tax law requires any modification to its tariff; however, if the Commission believes state law mandates such a change, CWSNC requested clarification and immediate authorization to collect the taxes in the interim.

The Public Staff stated in its reply comments that the change in the taxable status of CIAC under the Tax Act could have a significant impact on water and wastewater companies in that contributed plant is a significant portion of the plant additions by these companies. The Public Staff recommended that the Commission open a new docket to address the implications of the inclusion of CIAC in taxable income for water and wastewater companies.

The Public Staff further recommended that the treatment of CIAC should follow the precedent established in Docket No. M-100, Sub 113, and that water and wastewater companies should seek to collect the income tax on CIAC from the contributor using the full gross-up method. The Public Staff recommended that the Commission allow individual companies seeking to use the present value method to do so with prior approval by the Commission. The Public Staff recommended that in opening a new docket, the Commission should provide notice of this change to all water and wastewater companies, not just the utilities subject to this docket[1], and direct those companies to seek to collect the income tax on CIAC from contributors of plant for new contributions contracted for on or after the date of the opening of that new docket.

The Commission concludes based on the comments filed that it is appropriate to open a generic water docket, Docket No. W-100, Sub 57, to consider the new tax status of CIAC under the Tax Act. The Commission is issuing an Order contemporaneously with this Order to open the new generic water docket. Therefore, any further consideration of this issue will be addressed in Docket No. W-100, Sub 57.

<u>Issue No. 4</u> – How should the Commission address the change in the federal corporate income tax rate in the various riders in effect?

DEC/DEP stated that they expect there may be additional benefits for customers through reduced rider rates, which will be handled in the respective annual rider filings and experience modification factors.

DENC noted that in addition to the Company's base non-fuel rate cost of service, the Tax Act impacts the Company's Rider EDIT, as approved in the Company's 2016 Base Rate Case Order. DENC noted that Rider EDIT is a decrement rider that refunds to customers over a two-year period, commencing on November 1, 2016 through October 31, 2018, a regulatory liability for EDIT associated with recent reductions in the North Carolina corporate income tax rate. DENC noted that the regulatory liability approved by the Commission was calculated using a tax gross-up factor that included a 35% federal income tax rate in effect prior to the enactment of the Tax Act. DENC maintained that beginning January 1, 2018, the federal corporate income tax component of the tax gross-up factor will be reduced from 35% to 21% pursuant to the Tax Act. DENC provided as Attachment 1 to its initial comments a schedule showing the reduction in the regulatory liability and the associated reduction to the Rider EDIT credit of $1.4 million for the period January 1, 2018 through October 31, 2018 due to the change in the tax gross-up factor.

[1] In its January 3, 2018 Order in this docket, the Commission excluded water and wastewater companies with $250,000 or less in annual operating revenues from participation in this proceeding.

DENC further noted that for the Company's rates and charges with approved deferral accounting and experience modification factors (i.e., fuel factor, DSM/EE, and REPS riders), the Company proposes to defer any differences between rates in effect at January 1, 2018, including any provisional components, and revenues that would have been billed incorporating the IRC as now amended by the Tax Act, through the ordinary deferral accounting process. DENC noted that any such differences will be addressed in future annual rider proceedings where applicable.

The Public Staff asserted that the rates for riders should be reduced in each subject utility's respective annual rider filings to reflect the reduction in the federal corporate income tax rate.

The Commission notes that all of the parties that commented on this issue agree that the Commission should address the reduction in the federal corporate income tax rate in the various riders for the utilities in each Company's next annual rider proceedings. Further, as noted by DENC, its State tax Rider EDIT established in its last general rate case was calculated using a 35% federal corporate income tax rate. The Commission finds it appropriate to request the Public Staff to work with DENC to determine the impact, if any, to DENC's State Tax Rider EDIT and file a recommendation with the Commission on how the Commission should address the decrease in the federal corporate income tax rate on DENC's State Tax Rider EDIT.

IT IS, THEREFORE, ORDERED as follows:

1. That, for the specific reasons outlined in this Order, it is not appropriate to adjust the base rates of Aqua, CWSNC, DEC, Frontier, or Toccoa in this generic rulemaking proceeding due to the reduction in the federal corporate income tax rate to 21% as enacted in the Tax Act.

2. That Cardinal, DENC, DEP, Piedmont, and PSNC are hereby required to adjust their base rates to reflect the reduction in the federal corporate income tax rate to 21% for taxable years beginning after December 31, 2017, as outlined in the Tax Act. PSNC's adjusted base rates should also include the necessary correction to appropriately reflect the 3% State corporate income tax rate.

3. That the following dockets are hereby created to accept Company-specific filings made pursuant to this Order:

DEC	Docket No. E-7, Sub 1184
DEP	Docket No. E-2, Sub 1188
DENC	Docket No. E-22, Sub 560
Piedmont	Docket No. G-9, Sub 731
PSNC	Docket No. G-5, Sub 595
Cardinal	Docket No. G-39, Sub 42

4. That Cardinal, DENC, DEP, Piedmont, and PSNC shall file proposals in the appropriate newly-created, Company-specific docket, including all supporting workpapers, to adjust their rates to reflect the reduction in the federal corporate income tax rate to 21% for taxable years beginning after December 31, 2017, as outlined in the Tax Act by no later than Thursday, October 25, 2018. The Public Staff is requested to file comments on the proposals by no later than

Wednesday, November 14, 2018. Other parties also may file comments on the proposals by no later than Wednesday, November 14, 2018.

5. That Cardinal, DENC, DEC, DEP, Piedmont, and PSNC shall continue to hold in a deferred regulatory liability account the difference between revenues billed under the prior federal corporate income tax rate and the federal corporate income tax rate resulting from the Tax Act starting January 1, 2018 as previously ordered in the Commission's January 3, 2018 Order and the disposition of such regulatory liability will be considered in each utility's next general rate case proceeding or in three years, whichever is sooner. Therefore, the Commission concludes that if Cardinal, DENC, DEC, 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 the difference between revenues billed under the prior federal corporate income tax rate and the federal corporate income tax rate resulting from the Tax Act starting January 1, 2018 as previously ordered in the Commission's January 3, 2018 Order. The proposal should include all workpapers that support the proposed calculations. The Public Staff is specifically requested to file comments on the proposal by no later than October 25, 2021. Other parties also may file comments on the proposal by no later than October 25, 2021. DEC is included in this decision because the issue of how to handle the provisional amounts collected since January 1, 2018 based on rates reflecting the 35% federal corporate income tax rate was not addressed in DEC's most recent rate case proceeding. These amounts will ultimately be returned to customers with interest reflected at the overall weighted cost of capital approved in each Company's last general rate case proceeding.

6. 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 with interest reflected at the overall weighted cost of capital approved in each Company's last general rate case proceeding. 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. The Public Staff is specifically requested to file comments on the proposal by no later than October 25, 2021. Other parties also may file comments on the proposal by no later than October 25, 2021. 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.

7. That excess deferred income taxes related to the decrease in the federal corporate income tax rate to 21% under the Tax Act for Aqua, CWSNC, and DEC will be or have been addressed in each Company's pending/recent general rate case proceeding.

8. That, once rates are established, the affected utilities (including DEC) shall file quarterly reports in the appropriate newly-created, Company specific docket, due no later than 30 days after the end of a quarter, on the status of their EDIT deferred account, and the deferral

account established under this proceeding that represents the difference between revenues billed under the prior federal corporate income tax rate and the federal corporate income tax rate resulting from the Tax Act starting January 1, 2018.

9. That the issue of the change in tax status of CIAC for water and wastewater public utilities under the Tax Act will be addressed in a separate proceeding, Docket No. W-100, Sub 57.

10. That the reduction in the federal corporate income tax rate reflected in the various riders for the utilities shall be addressed in each Company's next annual rider proceedings.

11. That the Public Staff is requested to work with DENC to determine the impact, if any, to DENC's State Tax Rider EDIT due to the Tax Act and to file a recommendation with the Commission on how the Commission should address the decrease in the federal corporate income tax rate on DENC's State Tax Rider EDIT by no later than Friday, November 2, 2018.

ISSUED BY ORDER OF THE COMMISSION.
This the 5th day of October, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. M-100, SUB 148

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
The Federal Tax Cuts and Jobs Act) CLARIFICATION ORDER
)

BY THE COMMISSION: On October 5, 2018, the Commission issued an Order Addressing the Impacts of the Federal Tax Cuts and Jobs Act on Public Utilities. The Commission ordered, among other things, 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 with interest reflected at the overall weighted cost of capital approved in each Company's last general rate case proceeding."

On October 25, 2018, Cardinal Pipeline Company, LLC (Cardinal) indicated in its compliance filing in Docket No. G-39, Sub 42, that Cardinal's rate base continues to be reduced by the excess deferred income taxes (EDIT) creating a benefit to customers; therefore, interest on the regulatory account is not necessary.

The Commission finds it appropriate to clarify its October 5, 2018 Order to state that for all of the impacted utilities if the EDIT remains a reduction to rate base, then no additional interest at the overall weighted cost of capital is required on the EDIT regulatory account.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 9th day of November, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. E-100, SUB 147

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Smart Grid Technology Plans Pursuant to Commission Rule R8-60.1(c)	))))))))	ORDER ACCEPTING DENC'S AND DEC'S SGTP UPDATES, REQUIRING ADDITIONAL INFORMATION FROM DEP, AND DIRECTING DEC AND DEP TO CONVENE A MEETING REGARDING ACCESS TO CUSTOMER USAGE DATA

BY THE COMMISSION: On September 30, 2016, Dominion Energy North Carolina (DENC) filed its smart grid technology plan (SGTP) in the above-captioned docket. On October 3, 2016, Duke Energy Progress, LLC (DEP) and Duke Energy Carolinas, LLC (DEC) filed their SGTPs in this docket. After several requests for extensions of time to file comments were granted by the Commission, comments were filed on December 19, 2016, by the Public Staff and North Carolina Sustainable Energy Association (NCSEA). Environmental Defense Fund (EDF) filed comments on December 20, 2016. On January 13, 2017, reply comments were filed by DENC, and jointly by DEP and DEC (collectively, Duke).

On March 29, 2017, the Commission issued an Order Accepting Smart Grid Technology Plans (2016 SGTP Order) in this docket. In the 2016 SGTP Order, the Commission found good cause to request that the electric utilities, the Public Staff, and all interested parties continue discussing potential rule changes related to access to customer usage data and that Duke include a report on those discussions in its 2017 SGTPs. Further, the Commission's Order cited several requirements of Commission Rule R8-60.1 with respect to the information to be provided by the electric public utilities for smart grid technologies currently being deployed or scheduled for implementation within the next five years, and stated:

> Neither DEC, DEP nor DNCP included the above information in their 2016 SGTPs with regard to any future plans for deployment of AMI meters. The Commission interprets this to mean that DEC, DEP and DNCP currently have no plans to replace existing meters with AMI meters, either incrementally or on full scale, during the next five years. As a result, the Commission expects DEC, DEP and DNCP to provide the Commission with the above information, as well as any other required information, in their SGTP filings prior to implementing an incremental or full scale effort to replace existing meters with AMI meters.

2016 SGTP Order, at p. 17.

On May 5, 2017, DEC and DEP filed supplemental information regarding DEC's and DEP's 2016 SGTPs. In summary, DEC advised the Commission that in late 2016 it decided to begin a full scale deployment of AMI in North Carolina, that it began implementing that decision in early 2017, and that it expects to complete its AMI deployment in North Carolina in 2019. DEC attached a cost-benefit analysis and other information regarding its decision to deploy AMI. With regard to DEP, the supplemental filing stated that DEP had not made a decision to deploy AMI.

On August 21, 2017, the Commission issued an Order Requiring Smart Meter Plan Presentation by Duke Energy Carolinas, LLC (SGTP Presentation Order). The Order scheduled a presentation on AMI by DEC, and included several questions to be answered by DEC regarding its decision to deploy AMI.

On August 25, 2017, DEC filed an application in Docket No. E-7, Sub 1146 requesting an increase in its retail rates. The request includes the costs associated with AMI deployment.

On October 2, 2017, in compliance with Commission Rule R8-60.1, DEP and DEC filed Smart Grid Technology Plan Updates (SGTP Updates). DENC filed a letter stating that there are no changes to its previous SGTP report.

On October 6, 2017, DEC filed its responses to the questions included in the Commission's SGTP Presentation Order (DEC's First Responses).

On October 10, 2017, DEC made its AMI presentation to the Commission.

On November 1, 2017, the Public Staff filed a letter stating that it reviewed DEC's and DEP's SGTP Updates and believes that they comply with the requirements of Commission Rule R8-60.1, and, therefore, recommends that the Commission find that the SGTP Updates comply with the requirements of the Rule. Further, the Public Staff states that because the SGTP Updates are intended to be informational the Public Staff does not take a position on the smart grid technologies being considered by the utilities.

On November 20, 2017, the Commission issued an Order Requiring Additional Information (Additional Information Order) requesting that DEC respond to several questions.

On December 15, 2017, DEC filed its responses to the questions included in the Commission's Additional Information Order (DEC's Second Responses).

On February 5, 2018, the Commission held a public witness hearing in this docket. No public witnesses attended the hearing.

On February 23, 2018, the Commission issued an Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase to DEP in Docket Nos. E-2, Subs 1131, 1142, 1103, and 1153). In that Order, the Commission determined, among other things, that it would not open a separate docket for grid modernization planning and/or revisions to existing Commission rules at this time. Rather, the Commission decided that it will reconsider such proposals pending the effectiveness of the planned Power/Forward technical workshop, SGTPs, integrated resource planning process, and the outcome of this issue in DEC's general rate case in Docket No. E-7, Sub 1146.

Background

By Orders dated April 11, 2012 and May 6, 2013, in Docket No. E-100, Sub 126, the Commission amended its rules requiring electric utilities that file integrated resource plans (IRPs) to include in their IRPs information on how planned "smart grid" deployment would impact the utilities' resource needs. Commission Rule R8-60.1 requires the electric utilities to file SGTPs every two years with updates in the intervening years. The initial SGTPs were filed by the electric utilities on October 1, 2014. The Commission, in its Order dated November 5, 2015, approved these 2014 SGTPs. In addition to approving the SGTPs, the Commission ordered (1) DEC, DEP, and DENC to address in their 2016 SGTPs whether the Commission's rules require updating to address customer and third party access to usage data and (2) DEC to address the issue of AMI opt-outs relative to its current and planned AMI deployments by December 1, 2015.

The Commission stated in the November 5, 2015 Order that smart grid proceedings are intended to be informative, and that the Commission does not anticipate using them to order utilities to make specific smart grid investments, nor are they a means by which utilities should seek to secure advance prudency reviews of smart grid investments.[1]

By Order dated June 13, 2016, in Docket No. E-100, Sub 126, the Commission amended Rules R8-60(i)(10) and R8-60.1 stating that the amended rules will better focus the SGTP proceedings as an informative effort to assist the Commission and parties in anticipating the potential impact of new technologies on customers.

Rule R8-60.1(c) states that

> For purposes of this Rule, smart grid technologies are as set forth in Rule R8-60(i)(10) and shall also include those that provide real-time, automated, interactive technologies that enable the optimization and/or operation of consumer devices and appliances, including metering of customer usage and providing customers with options to control their energy consumption.

Rule R8-60.1(c) lists the information to be included in each utility's SGTP. In summary, the Rule requires a description of the technologies, goals, and objectives of each technology, the status and timeframe for completion of the project, and cost information. In addition, Rule R8-60.1(c)(7) requires additional details about plans and ongoing deployments of AMI.

Summary of Smart Grid Technology Plans

Duke Smart Grid Technology Strategy

In 2017, Duke outlined its plans over the next decade to modernize the North Carolina grid by means of its Power/Forward Carolinas initiative. In summary, Duke maintains that Power/Forward is comprised of strategic programs that will each play a part in building a smarter energy future for customers. According to Duke, these strategic programs represent the means to deliver the road ahead strategies of modernizing the power grid and transforming the customer experience, as outlined in the 2016 SGTPs. Moreover, Duke asserts that the early years of

[1] It should be noted, however, that G.S. 62-42 grants the Commission authority to order an investor-owned utility to make equipment improvements if necessary to assure that customers receive adequate and sufficient electric service.

Power/Forward will establish the foundational and enabling infrastructure and technologies to achieve Duke's long-term objectives of a more reliable, resilient grid to better serve customers.

According to Duke, certain programs included in the Power/Forward initiative are technologies that fall under the definition of "smart grid technologies" outlined in Commission Rule R8-60.1(c), while others are not. All of the programs have similar objectives in the long term, improving reliability and resiliency of the grid; however, certain programs, like Targeted Undergrounding, are not deemed smart grid technologies. Duke has determined that the Self-Optimizing Grid, and certain portions of the Enterprise Systems Upgrades, Communications Network Upgrades, and Transmission Improvements programs meet the criteria for the SGTP and will be outlined within its SGTPs each year as applicable. The Enterprise Systems Upgrades primarily consists of the Distribution Management System (DMS) Consolidation projects as outlined in the 2016 SGTPs. According to Duke, applicable projects or initiatives are included in the 2017 SGTP Updates or will be included in future SGTPs as appropriate.

Duke states that the initial planning for the 10-year Grid Improvement Plan was completed in early 2017. Given this is a 10-year plan, Duke will utilize a "progressive elaboration" process, pursuant to Project Management Institute best practices, to govern the plan throughout the lifecycle. In this process, the initial overall 10-year plan concepts are approved first, then a more detailed version of each year's plan is submitted and approved annually.

Following are smart grid technologies identified in Duke's updated plans:

<u>DEC Current and Scheduled Technology Deployments – R8-60.1(c)(3)</u>

- AMI Deployment
- Self-Optimizing Grid
- Usage Alerts
- Pick Your Own Due Date

<u>DEC Technologies Actively Under Consideration – R8-60.1(c)(4)</u>

- Enterprise Transmission Health & Risk Management Project
- Enterprise Communications Network Upgrades Program

<u>DEP Current and Scheduled Technology Deployments – R8-60.1(c)(3)</u>

- AMI Deployment
- Self-Optimizing Grid

<u>DEP Technologies Actively Under Consideration – R8-60.1(c)(4)</u>

- Capacitor Bank Controls Upgrade
- Enterprise Transmission Health & Risk Management Project
- Western Carolinas Energy Storage Analysis and Deployment Plan
- Enterprise Communications Network Upgrades Program

DENC Smart Grid Technology Strategy

DENC states that it continually evaluates technologies to provide value-added services to customers and improve operations. Smart grid technologies are evaluated using standard DENC processes. DENC's strategy for evaluating and developing smart grid technologies includes assessing existing capabilities and evaluating new capabilities required to achieve the Company's targeted business objectives. After evaluating the new capabilities required for a targeted objective, a cross functional leadership team reviews the new capabilities to determine how they fit into the Company's overall corporate strategy. During this review, the team identifies high priority capabilities with consideration to business needs and budgetary constraints.

At the completion of the cross functional leadership team review, DENC focuses significant effort on developing the high priority capabilities necessary to achieve the targeted objective. The development includes researching available technologies, reviewing industry trends, and evaluating technologies from a technical, financial, and policy perspective.

DENC Current and Scheduled Technology Deployments – R8-60.1(c)(3)

All technologies included in the SGTP are in the pilot phase. DENC does not have capital allocated for deployment of additional smart grid technologies.

Discussion of SGTP Updates

AMI Deployment

Commission Rule R8-60.1(c)(3), subsections (ii), (iii) and (vii), require that SGTPs include the following information, among other things, for technologies currently being deployed or scheduled for implementation within the next five years:

(ii) The status and timeframe for completion.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at the time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

DEC - AMI

In the AMI cost-benefit analysis filed by DEC as a part of its supplemental information filing on May 5, 2017, DEC concluded that its AMI deployment would result in net benefits having a present value of $117.1 million (Supplemental Filing, Exhibit A). The largest category of benefits included in the analysis is entitled "Non-technical line loss reduction - power theft, equipment failures and installation errors." It is the last column of benefits shown on Exhibit A, and totals $634.8 million. In comparison, the next largest category of benefits is "Reduced meter operations costs – consumer order workers for meter orders," a total of $175.4 million. In response to question number 2 included in the Commission's SGTP Presentation Order, DEC stated, in pertinent part:

> According to a 2008 EPRI report, industry experts project that a reasonable percentage for non-technical losses is 2% of gross revenue. This assumption was utilized in calculating the DEC AMI benefits.

DEC's First Responses, at p. 5.

During DEC's SGTP presentation, DEC witness Donald Schneider, Jr. was asked whether EPRI or any other entity did a physical real world study to verify the 2% non-technical losses figure. Witness Schneider responded:

> Not to my knowledge. I think they went on data. Again, this was a report, not necessarily a study but it was a report, and they were going off of other reports and studies going back years and years that came up with this on average 2 percent of gross revenues so they did not.

Transcript, at p. 40.

Witness Schneider also stated that DEC has not performed a study that confirms the 2% amount reported by EPRI. In addition, witness Schneider stated that based on DEC's cost-benefit analysis the costs of the AMI deployment would outweigh the benefits until 2025 (Transcript, at p. 44).

In the Commission's Additional Information Order, the Commission requested that DEC provide the following information:

> 8. Using the actual historical kilowatt-hour and lost revenue data for energy theft that DEC has experienced and is discovering in North Carolina, including during its AMI deployment, develop an independent estimate of the percent of additional revenues DEC will collect via that deployment that would otherwise be lost due to theft and other non-technical losses.
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> 9. Provide a revised 20-year AMI cost-benefit analysis that includes: (a) the costs of replacing AMI meters at the end of their 15-year lives, (b) the most recent estimate of the costs of cellular direct connect meters, (c) the cost of replacing other components and software at reasonable intervals, and (d) the non-technical revenue loss estimate (rather than the EPRI 2% estimate) developed pursuant to question 8.

DEC's revised AMI cost-benefit analysis was attached to DEC's Second Responses as Exhibit No. 2. The largest category of benefits included in the analysis continues to be "Non-technical line loss reduction - power theft, equipment failures and installation errors." However, the amount of this benefit went down from $634.8 million to $448.8 million. In addition, the revised cost-benefit analysis shows that AMI deployment would result in net costs having a present value of $49.9 million (DEC's Second Responses, Exhibit No. 2).

In DEC's SGTP Update, on pages 6-8, DEC provides the information regarding its AMI deployment. In summary, DEC states that through August 2017 it has installed approximately 850,000 AMI meters in North Carolina, and plans to install an additional 1.1 million AMI meters through 2019. Further, DEC states that it will remove and replace approximately 1.32 million automatic meter reading (AMR) meters from 2017 through 2019. DEC states that the AMR meters have an estimated salvage value of $1.37 million, and an estimated remaining net book value of $127.66 million as of March 31, 2017. In Exhibit A, Appendix C, DEC provides its AMI cost-benefit analysis, which is the same analysis that DEC filed as a part of its supplemental information filing on May 5, 2017.

In DEC's general rate case application, Docket No. E-7, Sub 1146, DEC seeks the recovery of $102.1 million in actual and estimated costs for AMI deployment from January through November 2017. In addition, DEC requests authority to establish a regulatory asset account to defer for later recovery the cost of meters that are being replaced by AMI. (Pre-filed Direct Testimony of Jane McManeus, at pp. 18-19)

DEP - AMI

In DEP's SGTP Update, on pages 6-8 and 17-18, DEP provides information regarding its plans for AMI deployment. In summary, DEP states that it has installed 56,819 AMI meters as of August 2017, and that it has installed approximately 182 AMI meters since the count provided in its 2016 SGTP. DEP states that its Board of Directors has endorsed the AMI deployment project, but "the outcome of regulatory considerations in the DEP rate case (Docket No. E-2, Sub 1142) could affect the Company's timing to advance the project." Further, DEP states that its existing AMR meters will have an estimated net book value of approximately $77.2 million as of December 31, 2017. In Exhibits A-G, Appendix C, DEP provides its AMI cost-benefit analysis. Similar to the initial cost-benefit analysis filed by DEC, DEP's analysis uses the EPRI 2% of revenues as a proxy for "Non-technical loss reduction."

Conclusions Regarding AMI

Commission Rule R8-60.1(c)(3) requires the electric utilities to provide the Commission with a cost-benefit analysis and other detailed information about smart grid technologies currently being deployed by the utilities or scheduled for implementation within the next five years. One purpose of the rule is to allow the Commission, the Public Staff, and other interested parties to review information about proposed smart grid programs, request additional information when needed, and have input regarding the implementation of smart grid programs well in advance of their implementation. Smart grid technologies are relatively new and evolving projects that require substantial capital investments. Therefore, the public interest is best served by the Commission and parties having sufficient time to study and understand the details of a smart grid project before it is launched.

As noted previously, DEC did not provide a cost-benefit analysis and other required information in its 2016 SGTP to support an AMI deployment. Consequently, the Commission directed DEC "[t]o provide the Commission with the above information, as well as any other required information, in their SGTP filings prior to implementing an incremental or full scale effort to replace existing meters with AMI meters." SGTP Order, at p. 17 [emphasis added] Nevertheless, DEC, as it reported in its May 5, 2017 supplemental filing, began deploying AMI meters "in early 2017."

Public utilities are required to provide cost effective services. G.S. 62-2. DEC's revised AMI-cost-benefit analysis, filed in response to the Commission's Additional Information Order, shows that on a present value basis the costs of DEC's AMI deployment are $49.9 million more than the benefits. The Commission acknowledges that an economic analysis is but one of the tools necessary to inform decisions such as the deployment of AMI. However, concerns are raised by a cost-benefit analysis that shows significant negative costs. The Commission notes that the question of AMI deployment by DEC is presented for decision in DEC's pending general rate case in Docket No. E-7, Sub 1146.

Based on the foregoing and the record in these dockets, the Commission finds good cause to accept DENC's SGTP Update, and to accept DEC's SGTP Update on the condition that DEC shall comply with the Commission's directive regarding discussions on access to customer usage data, as set forth below.

With regard to the AMI portion of DEP's Update, the Commission finds good cause to require that DEP file a revised AMI cost-benefit analysis using the same guidelines as requested of DEC in the Commission's Additional Information Order, to wit:

> 8. Using the actual historical kilowatt-hour and lost revenue data for energy theft that DEP has experienced and is discovering in North Carolina, including during its AMI deployment, develop an independent estimate of the percent of additional revenues DEP will collect via that deployment that would otherwise be lost due to theft and other non-technical losses.
>
> 9. Provide a revised 20-year AMI cost-benefit analysis that includes: (a) the costs of replacing AMI meters at the end of their 15-year lives, (b) the most recent estimate of the costs of cellular direct connect meters, (c) the cost of replacing other components and software at reasonable intervals, and (d) the non-technical revenue loss estimate (rather than the EPRI 2% estimate) developed pursuant to question 8.

Access to Customer Usage Data

In the Commission's 2016 SGTP Order, the Commission declined to consider a usage data access rule proposed by North Carolina Sustainable Energy Association (NCSEA), and, instead, requested that the parties continue their discussions on the subject and report back to the Commission.

> The Commission encourages the electric utilities, the Public Staff, and all interested parties to continue meeting and discussing rule changes related to customer usage data and third party access. The Commission recognizes there are many factors the stakeholders must consider when proposing rule changes to provide easy access to granular energy consumption data. These include, but are not limited to, customer privacy, liability, authorizations, Codes of Conduct, and affiliate transactions which should be appropriately addressed in the parties'

> discussions. Therefore, rather than initiating a formal rulemaking docket at this time, the Commission requests that Duke include a report on the discussions regarding potential rule changes in Duke's 2017 SGTPs.
>
> The Commission appreciates NCSEA's efforts to develop and propose a new Commission Rule R8-51.1 addressing data access.[1] However, the Commission chooses not to offer discussion, findings or conclusions on the proposed rule pending the above referenced rulemaking discussions and report.

2016 SGTP Order, at 23.

In their SGTP Updates, DEC and DEP (collectively, Duke) provide their report regarding discussions on potential changes to the rules governing access to customer usage data. Duke states, in pertinent part:

> Since the issuance of the Commission's March 29, 2017 SGTP Order, DEC and DEP have not had any formal discussions with NCSEA and the Public Staff regarding potential rule changes to address data access issues. DEC and DEP had some discussions related to data access issues with NCSEA and the Public Staff in the context of a legislative stakeholder process, but no such legislation was ultimately enacted. The Companies remain willing to have further discussions should the Commission decide to engage in such rulemaking.

SGTP Updates, at p. 19.

<u>Conclusion (Access to Customer Usage Data)</u>

The Commission is aware of the stakeholder discussions surrounding the proposed legislation referenced by Duke. The stakeholder discussions, like the proposed legislation, were wide ranging, and perhaps did not present an optimal opportunity for the parties to focus on the question of guidelines for access to customer usage information. During the DEP general rate case proceeding (Docket No. E-2, Sub 1142), Mr. Somers stated that "If NCSEA or the Public Staff or any other party is interested in talking about data access, the Company is more than willing to do so at any reasonable time." (Tr. Vol. 12, p. 256) Therefore, the Commission finds good cause to direct that Duke convene and facilitate discussions with NCSEA, the Public Staff, and other interested parties on this topic, with the goal of reaching agreement on all aspects, or as many aspects as possible, of the rule proposed by NCSEA. The first meeting shall be convened on or before June 4, 2018. In addition, the Commission requests that the discussions include the Green Button Connect My Data system for data access. The Commission further directs that Duke provide the Commission a report detailing the discussions, agreements reached on particular points, points on which agreement has not been reached, and the barriers to agreement on remaining points, as well as the parties' plans for further discussions. The report shall be filed in Docket E-100, Sub 147 no later than 30 days after the first meeting of the stakeholder group. Further, the Commission directs Duke to reflect the results of these discussions in its 2018 SGTP reports.

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[1] NCSEA Comments, Exhibit C, Docket No. E-100, Sub 147 (December 19, 2016).

IT IS, THEREFORE, ORDERED as follows:

1. That DENC's letter identifying no changes to its previous SGTP report is accepted.

2. That DEC's SGTP Update is accepted, with the condition that DEC shall comply with the Commission's directive regarding discussions on access to customer usage data, as set forth herein.

3. That DEP shall within three months of the date of this Order file a revised AMI cost-benefit analysis as described in the body of this Order.

4. That Duke shall convene meetings with NCSEA, the Public Staff, and other interested parties to discuss guidelines for access to customer usage data, as specified in the body of this Order. The first meeting shall be convened on or before June 4, 2018. Duke shall file a report with the Commission, no later than 30 days after the first meeting, providing the Commission with the details of the discussions, and the parties' plans for further discussions. Duke shall reflect the results of these stakeholder discussions in its 2018 SGTP reports.

ISSUED BY ORDER OF THE COMMISSION.
This the 7th day of March, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

Commissioner Charlotte A. Mitchell did not participate in this decision.

DOCKET NO. E-100, SUB 151

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Proceeding to Select the Independent	)	ORDER APPROVING THE
Administrator of the CPRE Program	)	INDEPENDENT ADMINISTRATOR
	)	OF THE CPRE PROGRAM

BY THE COMMISSION: On November 21, 2017, pursuant to Commission Rule R8-71(d)(1), the Commission issued an Order establishing this proceeding to select the Independent Administrator of the Competitive Procurement of Renewable Energy (CPRE) Program, which was created by the enactment of G.S. 62-110.8. That Order allowed the parties of record in Docket No. E-100, Sub 150 to participate in this proceeding without the need to file petitions to intervene, including the North Carolina Clean Energy Business Alliance (NCCEBA), the North Carolina Sustainable Energy Association (NCSEA), and the North Carolina Utilities Commission-Public Staff (Public Staff).

On December 8, 2017, pursuant to Ordering Paragraph One of the Commission's November 21 Order, Duke Energy Carolinas, LLC (DEC) and Duke Energy Progress, LLC (DEP) (together, Duke), filed their initial comments and recommendation that the Commission select Accion Group, LLC (Accion), as the Independent Administrator of the CPRE Program. Duke's filing included background on the CPRE Program and details on Duke's due diligence efforts to identify candidates to serve as Independent Administrator of the CPRE Program. Duke states that this process included developing a scope of work, interviewing Accion and three other candidate firms, and seeking performance feedback and reviews from Duke's peer utilities, among other reference sources. Duke further states that due to the truncated timeframe of required filings, after the initial interviews, Duke focused on Accion as the lead candidate and did not solicit proposals from the other candidate firms that were initially interviewed; however, Accion was not informed that it was the only candidate firm invited to make a formal proposal, which was included as an attachment to Duke's filing.

In support of its recommendation, Duke states that Accion maintains a nationwide practice conducting utility solicitations, having participated in over 94 solicitations during the past 13 years involving a wide variety of technologies, fuel sources, and terms. Duke further states that Accion has served as independent evaluator, independent monitor, or independent observer to a number of state commissions and utilities in jurisdictions that include Georgia, Colorado, and California. Duke also described Accion's background and experience in evaluating capacity and energy supply options in these other states, including providing independent expertise in the evaluation of bids and the design and development of sophisticated competitive procurement websites that provide the equal access to information and the transparency required by Commission Rule R8-71. Duke further states that Accion's proposed budgets are reasonable inasmuch as they are in line with the charges for similar work in other states and Duke's previous experience for similar services. Finally, Duke states that Accion made the disclosures required by Commission Rule R8-71(d)(2), and that no conflict of interest exists that would affect Accion's independence or ability to perform the Independent Administrator role in an unbiased manner. Therefore, Duke requests that the Commission approve Accion as the third-party Independent Administrator of the CPRE Program.

On December 19, 2017, NCCEBA filed reply comments, stating that NCCEBA has no objection to Duke's recommendation of Accion as the Independent Administrator of the CPRE Program.

On December 21, 2017, the Public Staff filed reply comments, stating that the Public Staff reviewed Duke's initial comments and recommendation and does not take exception with the process followed by Duke in identifying and evaluating candidate firms with experience monitoring and supporting competitive procurement programs for electric utilities. The Public Staff further states that it is satisfied with Duke's due diligence in evaluating Accion's qualifications and experience. The Public Staff also summarized its own "high-level survey" of firms that provide the type of services sought in the Independent Administrator, which included contacting the staff of the Georgia Public Service Commission and two meetings with Accion to discuss its qualifications and experience. Based upon this effort, the Public Staff states that Accion has the experience and resources to meet the requirements of the Independent Administrator of the CPRE Program and that the Public Staff does not object to Duke's recommendation. Finally, the Public Staff states that it believes that the Commission has sufficient information to select an

Independent Administrator, but a presentation of Accion's skills and qualifications may be informative for the Commission and other parties and useful for the Commission's consideration.

On December 22, 2017, NCSEA filed a letter in lieu of reply comments, informing the Commission that NCSEA has no objection to Duke's recommendation that Accion serve as the Independent Administrator of the CPRE Program.

No other party filed comments, and no additional interested persons have sought to intervene in this proceeding.

The Commission has carefully considered Duke's initial comments and recommendation, including Duke's Solicitation Scope of Work and Accion's proposal, which were attached to Duke's initial comments and recommendation, and the comments of the parties filed in this proceeding. Based upon the foregoing, and pursuant to G.S. 62-110.8(d), the Commission finds good cause to approve Accion as the Independent Administrator of the CPRE Program.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 9th day of January, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. E-100, SUB 158

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Biennial Determination of Avoided Cost	)	ORDER ESTABLISHING BIENNIAL
Rates for Electric Utility Purchases from	)	PROCEEDING, REQUIRING DATA,
Qualifying Facilities – 2018	)	AND SCHEDULING PUBLIC HEARING

BY THE COMMISSION: These are the 2018 biennial proceedings held by this Commission pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) and the Federal Energy Regulatory Commission (FERC) regulations implementing those provisions, which delegated to this Commission certain responsibilities for determining each utility's avoided costs with respect to rates for purchases from qualifying cogenerators and small power production facilities. These proceedings are also being held pursuant to G.S. 62-156 which requires this Commission to determine the rates to be paid by electric utilities for power purchased from small power producers as defined in G.S. 62-3(27a).

In order to facilitate the determination of avoided cost rates, the Commission finds good cause to issue this order establishing a schedule for the 2018 biennial determination of such rates in this docket. The Commission further finds that Duke Energy Carolinas, LLC (DEC), Duke

Energy Progress, LLC (DEP), Virginia Electric and Power Company d/b/a Dominion Energy North Carolina (Dominion), Western Carolina University (WCU), and Appalachian State University, d/b/a, New River Light and Power Company (New River) should be made parties to these proceedings.

In Ordering Paragraph No. 16 of its October 11, 2017 Order issued in Docket No. E-100, Sub 148 (the 2016 biennial avoided cost proceedings), the Commission directed DEC, DEP, and Dominion to address the following issues in their initial filings in this proceeding, consistent with the discussion and conclusions reached in that Order: (1) a continued evaluation of capacity benefits of QF generation, (2) whether the utilization of a 2.0 PAF as approved in the Hydro Stipulation should continue as provided in that agreement, (3) the effect of distributed generation on power flows on each utility's distribution system and the extent of power backflows at substations, (4) hourly CT operational data and marginal cost data on a season-specific basis, and (5) consideration of a rate design that considers factors relevant to the characteristics of QF-supplied power that is intermittent and non-dispatchable. With regard to a rate design that considers the characteristics of the power supplied by the QF, and consistent with the testimony of the parties' witnesses in the 2016 biennial avoided cost proceedings, the Commission expects DEC, DEP, and Dominion to file proposed rate schedules that reflect each utility's highest production cost hours, as well as summer and non-summer periods, with more granularity than the current Option A and Option B rate schedules. Further, in its discussion of the other issues addressed by the witnesses in the 2016 biennial avoided cost proceedings, the Commission determined that a number of issues merit further consideration in this proceeding. Therefore, the Commission will require DEC, DEP, and Dominion to address those issues as directed in Ordering Paragraph No. 16 of the Commission's October 11, 2017 Order in Docket No. E-100, Sub 148, through their respective filings in this proceeding. In addition, the Commission invites all parties to address those issues which the Commission determined in its October 11, 2017 Order in Docket No. E-100, Sub 148, merit further discussion, but were not specifically mentioned in Ordering Paragraph No. 16.

The Commission has determined that it will attempt to resolve all issues arising in this docket based on a record developed through public witness testimony, statements, exhibits and avoided cost schedules verified by persons who would otherwise be qualified to present expert testimony in a formal hearing, and written comments on the statements, exhibits and schedules, rather than a full evidentiary hearing for the purpose of receiving expert testimony. The Commission believes this procedure is appropriate given the recurring nature of the issues and decisions which have traditionally arisen in these proceedings.

IT IS, THEREFORE, ORDERED as follows:

1. That DEC, DEP, Dominion, WCU, and New River are hereby made parties to these proceedings;

2. That DEC, DEP, Dominion, WCU, and New River shall file the statements and exhibits specified in decretal paragraph 3 below on or before Thursday, November 1, 2018;

3. That DEC, DEP, Dominion, WCU, and New River's filings shall include the following:

a. A set of proposed rates for purchases from qualifying facilities, showing all calculations for deriving said proposed rates, including inflation rates and discount rates used,

b. Proposed standard form(s) of contract between qualifying facilities and the utility, describing any differences between said proposed standard form(s) of contract and the currently approved standard contract, including the reasons for such differences; and

c. Statements and exhibits addressing those issues listed in Ordering Paragraph No. 16 of the Commission's October 11, 2017 Order issued in Docket No. E-100, Sub 148.

4. That other persons desiring to become formal parties to this proceeding may petition the Commission for leave to intervene on or before Monday, January 7, 2019;

5. That all parties, other than the five electric utilities herein, shall file with the Commission the comments and exhibits that they wish to present in this proceeding on or before Monday, January 7, 2019;

6. That all parties may file reply comments on or before Friday, February 15, 2019;

7. That all parties may file proposed orders on or before Friday, March 8, 2019;

8. That a public hearing solely for the purpose of taking nonexpert public witness testimony is hereby scheduled to begin on Tuesday, February 19, 2019, at 9:30 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina; and

9. That DEC, DEP, Dominion, WCU, and New River shall publish, at their own expense, in newspapers having general circulation in their respective North Carolina service areas, the "Notice of Public Hearing" attached hereto as Appendix A once a week for two successive weeks, beginning with the week of December 3, 2018, and shall submit Affidavits of Publication to the Commission no later than the date of the hearing.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of June, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

APPENDIX A
PAGE 1 OF 2

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 158

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Biennial Determination of Avoided Cost	)	
Rates for Electric Utility Purchases from	)	NOTICE OF PUBLIC HEARING
Qualifying Facilities – 2018	)	

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission (Commission) has scheduled a public hearing in this docket which will commence on Tuesday, February 19, 2019, at 9:30 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, for the purpose of taking nonexpert public witness testimony as a part of its 2018 biennial determination of avoided cost rates for purchases of electricity by the electric utilities who are parties to this docket from qualifying cogeneration and small power production facilities. The electric utilities who are parties to this docket are Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP), Virginia Electric and Power Company d/b/a Dominion Energy North Carolina (Dominion), Western Carolina University (WCU), and Appalachian State University, d/b/a, New River Light and Power Company (New River).

The Public Utility Regulatory Policies Act of 1978 (PURPA) requires electric utilities to offer to purchase electric energy from cogeneration and small power production facilities which obtain qualifying facility status under PURPA. The rates for such purchases shall be set by the state regulatory authority, shall be just and reasonable to the ratepayers of the electric utility and in the public interest, shall not discriminate against qualifying cogenerators or qualifying small power producers, and shall not exceed the incremental cost to the electric utility of acquiring alternative electric energy. As a part of its responsibility in these matters, the Commission determines on a biennial basis the avoided cost rates and conditions for the purchase of electricity by electric utilities from qualifying cogeneration and small power production facilities in North Carolina.

In addition to the requirements of PURPA, G.S. 62-156 requires the Commission to determine the rates and contract terms to be observed by electric utilities in purchasing power from small power producers as defined in G.S. 62-3(27a). The rates established pursuant to G.S. 62-156 shall not exceed, over the term of the purchase power contract, the incremental cost to the electric utility of the electric energy which, but for the purchase from a small power producer, the utility would generate or purchase from another source.

APPENDIX A
PAGE 2 OF 2

The purpose of the hearing cited in this Notice is to consider revision of the avoided cost rates and contract terms previously set by the Commission for the purchase of electricity by the electric utilities who are parties to this proceeding from qualifying cogeneration and small power production facilities in North Carolina.

The Public Staff is required by statute to represent the using and consuming public in proceedings before the Commission. Written statements to the Public Staff should include any information which the writer wishes to be considered by the Public Staff in its investigation of the matter, and such statements should be addressed to Mr. Christopher J. Ayers, Executive Director, Public Staff — North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300.

The Attorney General is also authorized by statute to represent consumers in proceedings before the Commission. Statements to the Attorney General should be addressed to The Honorable Josh Stein, Attorney General of North Carolina, c/o Utilities Section, 9001 Mail Service Center, Raleigh, North Carolina 27699-9001.

Written statements are not evidence unless those persons submitting such statements appear at a public hearing and testify concerning the information contained in their written statements.

Any person desiring to intervene in the matter as a formal party of record should file a motion under Commission Rules R1-5 and R1-19 no later than Monday, January 7, 2019. All such motions should be filed with the Chief Clerk of the North Carolina Utilities Commission, 4325 Mail Service Center, Raleigh, North Carolina 27699-4325. The comments and exhibits to be presented in this proceeding by formal parties other than DEC, DEP, Dominion, WCU, and New River must be filed with the Commission no later than Monday, January 7, 2019.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of June, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

NOTE TO PRINTER: Cost of Advertising will be paid by the Applicant. It is required that an Affidavit of Publication be submitted to the Commission by the Applicant.

DOCKET NO. E-100, SUB 159

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
2018 REPS Compliance Plans and	)	ORDER ESTABLISHING DATES FOR
2017 REPS Compliance Reports	)	COMMENTS ON REPS COMPLIANCE
	)	PLANS AND REPS COMPLIANCE
	)	REPORTS

BY THE CHAIRMAN: Between August 20 and September 4, 2018, the following municipal electric power suppliers, electric membership corporations, and REPS compliance aggregators filed their 2018 Renewable Energy and Energy Efficiency Portfolio Standard (REPS) compliance plans and 2017 REPS compliance reports: EnergyUnited Electric Membership Corporation, North Carolina Eastern Municipal Power Agency, North Carolina Municipal Power Agency Number 1, North Carolina Electric Membership Corporation, the Town of Waynesville, the Tennessee Valley Authority, Public Works Commission of the City of Fayetteville, and Halifax Electric Membership Corporation. In addition, NTE Carolinas, LLC (NTE), filed a letter stating that the Towns of Black Creek, Lucama, Sharpsburg, Statonsburg, and Winterville are now full requirements power supply customers of NTE, and that the Cities of Kings Mountain and Concord will become NTE full become full requirements power supply customers of NTE on January 1, 2019. NTE further states that it is assisting these towns in preparing and filing their respective REPS compliance plans, but is unable to do so at this time because the towns are waiting on certain information to be provided by their current or former power suppliers.

The Chairman finds good cause to establish January 31, 2019, as the deadline for the filing of petitions to intervene and initial comments by the Public Staff and by intervening parties, and February 28, 2019, as the deadline for filing reply comments in this proceeding.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 27th day of September, 2018.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Acting Deputy Clerk

GENERAL ORDERS – ELECTRIC RESELLER

DOCKET NO. ER-100, SUB 4

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Rulemaking to Implement North Carolina	)	ORDER INITIATING
Session Law 2017-172 (House Bill 799)	)	RULEMAKING PROCEEDING

BY THE COMMISSION: On July 21, 2017, North Carolina Session Law 2017-172 (House Bill 799) was signed into law by the Governor, having been previously ratified by the North Carolina General Assembly. This legislation, entitled "An Act to Allow For Landlords to Charge Individual Tenants for Shared Cost of Natural Gas Service Provided to Leased Premises," among other things, modifies certain terminology used in G.S. 42-42.1, Water, Electricity, and Natural Gas Conservation, and modifies G.S. 62-110(h) to allow lessors of a single-family dwelling, and lessors of a residential building the ability to resell electric service and to remove the statutory requirement that an apartment complex that leases by the bedroom have a separate lease for each bedroom. These statutory changes became effective July 21, 2017.

In order to implement the provisions of House Bill 799, the Commission proposes certain revisions to the Rules and Regulations in Chapter 22 Provision of Electric Service By Landlords as presented in Appendix A attached hereto and certain revisions to the application and transfer forms as presented in Appendices B and C.

WHEREUPON, the Commission finds good cause to initiate a rulemaking proceeding to implement the statutory changes to G.S. 42-42.1 and G.S. 62-110(h) required by Senate Bill 799. Interested parties are requested to file initial comments and reply comments on the Commission's proposed changes to the Rules and Regulations in Chapter 22 and the proposed changes to Forms ER-1 and ER-2 to assist the Commission in adopting final rules and applicable Commission forms. After careful consideration of the initial comments and reply comments the Commission will issue final rules and forms.

IT IS, THEREFORE, ORDERED as follows:

1. That the proposed revisions to Commission Rules and Regulations contained in Chapter 22, attached as Appendix A (a clean copy and a version reflecting the proposed revisions[1]); Form ER-1, attached as Appendix B; Form ER-2, attached as Appendix C; are hereby adopted on an interim basis effective as of the date of this Order and continuing in effect until final rules shall be adopted and issued by further order of the Commission.

[1] Deletions from the current wording of the rules are shown by strikethrough and additions are shown by underlining.

2. That the Chief Clerk shall serve a copy of this Order on all providers charging for electric service pursuant to certificates of authority granted by the Commission pursuant to G.S. 62-110(h) and Chapter 22 of the Commission's Rules and Regulations, all providers with pending applications seeking such certificates of authority, the Public Staff – North Carolina Utilities Commission, and the Attorney General.

3. That any person having an interest in this proceeding may file a petition to intervene and initial comments on the proposed rules and proposed forms under the circumstances described herein on or before Friday, March 9, 2018, and may file reply comments on or before Friday, March 16, 2018.

4. That, after receiving comments and reply comments from interested parties the Commission shall issue a further order of the Commission concerning the applicable changes to Chapter 22 of the Commission's Rule and Regulations.

ISSUED BY ORDER OF THE COMMISSION.
This the 1st day of March, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

Commissioner Tonola D. Brown-Bland did not participate in this decision.
Commissioner Charlotte A. Mitchell did not participate in this decision.

APPENDIX A

CHAPTER 22.

PROVISION OF ELECTRIC SERVICE BY LESSORS.

Rule R22-1. APPLICATION.

Pursuant to G.S. 62-110(h), this Chapter governs the resale of electricity by a lessor of a single-family dwelling, residential building or multiunit apartment complex that has individually metered units for electric service in the lessor's name, where the lessor charges the actual costs of providing electric service to each lessee.

Rule R22-2. DEFINITIONS.

(a) *Lessee.* A person who purchases electric service from a provider.

(b) *Lessor.* A person, entity, corporation, or agency who owns a residential building, single-family dwelling or multiunit apartment complex which are available for lease. The lessor is also known as the landlord.

(c) *Multiunit apartment complex.* Premises where one or more buildings containing multiple residential dwelling units under common ownership are available for rental to lessees.

(d) *Provider.* A lessor who purchases electric utility service from a supplier and charges for the costs of providing the service to lessees. A provider must be the owner of the premises served.

(e) *Residential building.* A townhouse, row house, condominium, mobile home, building, or other structure used for residential purposes.

(f) *Single-family dwelling.* An individual, freestanding, unattached dwelling unit, typically built on a lot larger than the structure itself, resulting in an area surrounding the house known as a yard, which is rented or available for rental as a residence.

(g) *Supplier.* A public utility or an agency or organization exempted from regulation from which a provider purchases electric service.

(h) *Supplier's Unit Electric Service Bill.* The actual amount charged by the supplier for the unit as a whole less any amount charged by the supplier that is not recoverable from the lessees such as connection or disconnection charges, provider late fees or amounts attributed to excess usage as provided in Rule R22-7(f).

Rule R22-3. UTILITY STATUS; CERTIFICATE.

(a) Every provider is a public utility as defined by G.S. 62-3(23)a.1. and shall comply with, and shall be subject to all applicable provisions of the Public Utilities Act and all applicable rules and regulations of the Commission, except as hereinafter provided.

(b) A provider who charges for electric service under this Rule:

- (1) is solely responsible for the prompt payment of all bills rendered by the supplier and is the retail customer of the supplier subject to all rules, regulations, tariffs, riders and service regulations associated with the provision of residential electric service to retail customers of the supplier;
- (2) is not considered a wholesale customer of the supplier; and
- (3) is not subject to the requirements of G.S. 62-133.8, 62-133.9, or Rules R8-67 through R8-69.

APPENDIX A

(c) No provider shall begin charging for the costs of providing electric service prior to applying for and receiving a certificate of authority from the Commission.

Rule R22-4. APPLICATION FOR AUTHORITY.

(a) Every application for authority to charge for the costs of providing electric service shall be in such form and detail as the Commission may prescribe and shall include:

(1) a description of the lessor, who is the applicant, including legal name and type of business entity, and a description of the property to be served, including business or marketing name if any, street address, and number of units;
(2) a description of the proposed billing method and billing statements;
(3) the proposed method of allocating the supplier's charges to the lessees;
(4) the administrative fee per lessee, returned check charge, and late payment charge, if any, proposed to be charged by the applicant, and the number of days after the bill is mailed or otherwise delivered when the late payment fee would begin to be applied;
(5) the applicant's plans for retention and availability of records;
(6) the name of and contact information for the applicant and its agents, including mailing address, email address, and telephone number;
(7) the name of and contact information for the supplier of electric service to the applicant's rental property;
(8) the current schedule of charges from the supplier;
(9) a copy of the lease forms to be used by the applicant for lessees who are billed for electric service pursuant to this Chapter;
(10) a statement indicating the particular provisions of the lease forms pertaining to billing for electric service;
(11) the verified signature of the applicant or applicant's authorized representative;
(12) the required filing fee;
(13) one (1) original and seven (7) collated copies of the application; and
(14) any additional information that the Commission may require.

(b) An applicant may submit for authority to charge for electric service for more than one property in a single application. Information relating to all properties covered by the application need only be provided once in the application.

(c) The Commission shall approve or disapprove an application within 60 days of the filing of a completed application with the Commission. If the Commission has not issued an Order disapproving a completed application within 60 days, the application shall be deemed approved; provided, however, no person or entity may charge for electric utility service in a manner inconsistent with Chapter 62 of the North Carolina General Statutes.

(d) An approved certificate of authority from the Commission to charge for the costs of providing electric service under these rules shall be delivered to the supplier from which the provider purchases electric service and include information in R22-4(a)(1) and (6).

Rule R22-5. BILLS OF THE PROVIDER.

(a) Bills for electric service sent by the provider to the lessee shall contain all of the following information:

(1) the Supplier's Unit Electric Service Bill for the unit and the amount of charges allocated to the lessee during the billing period;

(2) the name of the supplier;

(3) the beginning and ending dates for the usage period and, if provided by the supplier, the date the meter for the unit was read for that usage period;

(4) the past-due date, which shall not be less than 25 days after the bill is mailed or otherwise delivered to the lessee;

(5) the name of the provider and a local or toll-free telephone number and address of the provider that the lessees can use to obtain more information about the bill;

(6) the amount of administrative fee, returned check charge, and the late payment charge approved by the Commission and included in the bill, if any; and

(7) a statement of the lessee's right to address questions about the bill to the provider and the lessee's right to file a complaint with, or otherwise seek recourse from, the Commission if the lessee cannot resolve an electric service billing dispute with the provider.

(b) The provider or the provider's billing agent shall equally divide the actual amount of the Supplier's Unit Electric Service Bill for a unit among all the lessees in the unit and shall send one bill to each lessee.

(c) The amount charged shall be prorated when a lessee has not leased the unit for the same number of days as the other lessees in the unit during the billing period.

(d) Each bill may include an administrative fee no greater than the amount authorized in Rule R18-6 for water service and, when applicable, a late payment charge no greater than the amount authorized in Rule R12-9(d) and a returned check charge no greater than the amount authorized in G.S. 25-3-506.

(e) A late payment charge may be applied to the balance in arrears after the past-due date.

(f) The provider may impose a returned check charge, not to exceed the maximum authorized by G.S. 25-3-506, for a check on which payment has been refused by the payor bank because of insufficient funds or because the lessee did not have an account at that bank.

(g) The provider shall not charge the cost of electricity from any other unit or common area in a lessee's bill. "Common area" means parts of the rental property outside the individually metered unit where the lessee dwells.

(h) No provider shall charge or collect any greater compensation for the costs of providing electric service than the rates approved by the Commission.

(i) The provider may, at the provider's option, pay any portion of any bill sent to a lessee, in accordance with the provisions of the lease; provided, however, that (i) the provider must still send each lessee bills in accordance with the other provisions in Rule R22-5; the provider must credit lessee bills or otherwise refund to lessees the amount, if any, by which the amount specified in the lease exceeds the amount actually owed by the lessee for electricity usage in the immediately preceding month; and (ii) the provider must comply with G.S. 62-140 regarding non-discrimination in billing for utility service.

Rule R22-6. RECORDS, REPORTS AND FEES.

(a) The provider shall maintain for a minimum of 36 months records that demonstrate how each lessee's allocated costs were calculated for electric service, as well as any other electric utility service-related fees charged to each lessee.

(b) All records required to be maintained by the provider pursuant to section (a), shall be kept at an office at the residential building or apartment complex or some other designated local address and shall be made available during regular business hours for inspection by a lessee, the Commission, or the

Public Staff. The lessee may obtain a copy of those records at a reasonable cost, which shall not exceed twenty-five cents (25¢) per page.

(c) Providers shall not be required to file an annual report to the Commission as required by Rule R1-32.

(d) Providers shall pay a regulatory fee and file a regulatory fee report as required by Rule R15-1.

(e) Special reports shall also be made concerning any particular matter upon request by the Commission.

Rule R22-7. DISCONNECTION; BILLING PROCEDURE.

(a) Any payment to the provider shall be applied first to the rent owed and then to charges for utility service, unless otherwise designated by the lessee.

(b) No charge for connection or disconnection or late fee or deposit paid by the provider to the supplier shall be allowed, and no provider may terminate a lease for nonpayment of electric service.

(c) No provider may disconnect or request the supplier to disconnect electric service for the lessee's nonpayment of a bill.

(d) Bills shall be rendered at least monthly.

(e) The date after which a bill for electric utility service is due (the past due date) shall be disclosed on the bill and shall not be less than twenty-five (25) days after the bill is mailed or otherwise delivered to the lessee.

(f) A provider shall not bill for or attempt to collect for excess usage resulting from a meter malfunction or other electrical condition in appliances such as water heaters, HVAC systems, or ranges furnished by the provider to the lessee, when the malfunction is not known to the lessee or when the malfunction has been reported to the provider.

(g) Every provider shall provide to each lessee at the time the lease agreement is signed, and shall maintain in its business office, in public view, near the place where payments are received, the following:

(1) A copy of the rates, rules and regulations of the provider applicable to the premises served from that office, with respect to electric utility service;

(2) A copy of these rules and regulations (Chapter 22);

(3) A statement advising lessees that they should first contact the provider's office with any questions they may have regarding bills or complaints about service, and that in cases of dispute, they may contact the Commission either by calling the Public Staff - North Carolina Utilities Commission, Consumer Services Division, at (866) 380-9816 (in-state calls only) or (919) 733-9277 or by appearing in person or writing the Public Staff - North Carolina Utilities Commission, Consumer Services Division, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326.

(h) Each provider shall adopt a means of informing its lessees initially and on an annual basis as to the provider's method of allocating bills to the individual lessees and its administrative fee, returned check charge, and late fee, if any. A copy of the supplier's current schedule of charges shall also be included in these disclosures.

(i) Every provider shall promptly notify the Commission in writing of any change in the information required in Rule R22-4(a), except for changes in the rates and charges of the supplier (Rule R22-4(a)(8)).

APPENDIX A

(j) If a provider anticipates that it will not pay a supplier's bill on time, or if the provider receives notice from the supplier of pending disconnection, whichever comes first, the provider must within 24 hours provide written notice to the Commission and all of the provider's affected lessees of the anticipated nonpayment or disconnection notice. A provider may not abandon or cease providing electric service to its lessees without advance permission from the Commission.

GENERAL ORDERS – ELECTRIC RESELLER

FORM ER-1
07/2017

APPENDIX B

DOCKET NO. ER-____ ,SUB ____
FILING FEE RECEIVED ______

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
APPLICATION FOR CERTIFICATE OF AUTHORITY TO RESELL ELECTRIC SERVICE IN ACCORDANCE WITH
G.S. 62-110(h) and NORTH CAROLINA UTILITIES COMMISSION CHAPTER 22

INSTRUCTIONS

If additional space is needed, supplementary sheets may be attached. If any section does not apply, write "not applicable."

Utility laws, the Commission's Rules, and other information may be accessed at http://www.ncuc.net/index.htm

APPLICANT

1. Name of owner ______________________________
   (Individual name if the owner is a sole proprietor or business name if not a sole proprietor.)
2. Business mailing address of owner ______________________________
   City and state ______________________________ Zip code __________
3. Business telephone number ______________________________ Business fax number _______
4. Business email address ______________________________

PROPOSED UTILITY SERVICE AREA
(Attach additional sheets if more than one property)

5. Name if residential building or apartment complex ____________
6. Street Address of single-family dwelling, residential building or apartment complex (hereinafter leased premises) ______________________________
7. County ______________________________
8. Name, address and telephone number of the supplier of purchased power ______________________________

   ____
9. Number of tenants that can be served at the leased premises: ______________________________

RESALE PROVISIONS

10. Describe the method Applicant proposes to use to allocate the supplier's individual electric bill for a unit among all the tenants in the unit (NCUC Rule R22-5) (Note: if the premises is a single-family dwelling or residential building there may be no allocation method): ______________________________

    ____

GENERAL ORDERS – ELECTRIC RESELLER

11. Monthly administrative fee per bill: ______

(Pursuant to NCUC Rule R22-5(d), no more than $3.75 per month – the maximum amount authorized for water reseller by Commission Rule R18-6, may be added to the cost of electric service as an administrative fee. The amount of administrative fee, up to the maximum amount, should be justified by Applicant's actual costs.)

12. Bills will be past due ____ days after they are mailed or otherwise delivered to the tenants. (NCUC Rule R22-7(e) specifies that bills shall not be past due less than twenty-five (25) days after mailing or other delivery to tenants.)

13. Late fee amount: ______

FORM ER-1
07/2017

APPENDIX B

(Pursuant to NCUC Rule R22-5(d) and (e), no more than 1% per month on balance in arrears.)
Number of days after mailing or other delivery of bills at which the late fee begins to apply: ______
(See NCUC Rule R22-5(e) and (7)(e).)

14. Returned check charge ______
(Pursuant to NCUC R22-5 and G.S. 25-3-506, no more than $25.00)

15. Statement of the Applicant's plans for retention and availability of records (see NCUC Rule R22-6(a) and (b)):

______

______

______

PERSONS TO CONTACT

	NAME	ADDRESS	TELEPHONE
16. Management	______	______ ______ Email ______	______
17. Complaints or Billing	______	______ ______ Email ______	______
18. Emergency Service	______	______ ______ Email ______	______
19. Filing and Payment of Regulatory Fees to Utilities Commission	______	______ ______ Email ______	______

OTHER PROVISIONS

20. Applicant must notify the Commission in writing within 30 days if any information supplied on this form changes in the future.

21. Applicant must also file quarterly Regulatory Fee Reports and make regulatory fee payments. Details are set out in NCUC Rule R15-1.

REQUIRED EXHIBITS

22. If the Applicant is a corporation, LLC, LP, or other legal business entity, enclose a copy of the certification from the North Carolina Secretary of State (Articles of Incorporation or Application for Certificate of Authority for Limited Liability Company, etc.). **(Must match name on Line 1 of application.)**

23. If the Applicant is a partnership, enclose a copy of the partnership agreement. **(Must match name on Line 1 of application.)**

24. Enclose a copy of a Warranty Deed showing that the Applicant has ownership of all the property necessary to operate the utility. **(Must match name on Line 1 of application.)**

25. Enclose a vicinity map showing the location of the leased premises in sufficient detail for someone not familiar with the county to locate the leased premises. (A county roadmap with the leased premises outlined is suggested.)

26. Enclose a copy of the supplier's schedule of rates that will be charged to the Applicant for purchased power.

27. Enclose a copy of any agreements or contracts that the Applicant has entered into covering the provision of billing and collections services to the leased premises.

28. Indicate the number of apartment buildings or residential buildings to be served, the number of units in each apartment building or residential building and the number of bedrooms in each unit.

29. Enclose a copy of the template or form used for billing statements.

30. Enclose a copy(ies) of the form(s) used for leases to tenants, including a statement of which parts of the lease relate to billing for electric service.

FILING INSTRUCTIONS

31. Submit one (1) original application with required exhibits and **original notarized signature**, plus seven (7) additional collated copies to: [USPS address] **Chief Clerk's Office, North Carolina Utilities Commission, 4325 Mail Service Center, Raleigh, North Carolina 27699-4325**, or [overnight delivery or hand delivery at street address] **Chief Clerk's Office, North Carolina Utilities Commission, 430 North Salisbury Street, Raleigh, North Carolina 27603.** Provide a self-addressed stamped envelope, plus an additional copy, if a file-stamped copy is requested by the Applicant.

32. Enclose a filing fee as required by G.S. 62-300. A Class A utility (annual electricity reseller revenues of $1,000,000 or more) requires a $250 filing fee. A Class B utility (annual electricity reseller revenues between $200,000 and $1,000,000) requires a $100 filing fee. A Class C utility (annual electricity reseller revenues less than $200,000) requires a $25 filing fee. **MAKE CHECK PAYABLE TO N.C. DEPARTMENT OF COMMERCE/UTILITIES COMMISSION.**

SIGNATURE

33. Application shall be signed and verified by an authorized representative of the Applicant.

Signature ______________________

Printed Name ______________________

Title ______________________

Date ______________________

34. (Typed or Printed Named) ______________________
personally appearing before me and, being first duly sworn, says that the information contained in this application and in the exhibits attached hereto is true to the best of his/her knowledge and belief.

This the _______ day of _______________, 20 ____

____
Notary Public

My Commission Expires: ______________________
Date

(NOTARY SEAL)

FORM ER-2
07/2017

APPENDIX C

SELLER DOCKET NO. ER-
PURCHASER DOCKET NO. ER-
FILING FEE RECEIVED ________

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

APPLICATION FOR TRANSFER OF AUTHORITY TO RESELL ELECTRIC SERVICE FOR LEASED PREMISES

INSTRUCTIONS

If additional space is needed, supplementary sheets may be attached. If any section does not apply, write "not applicable".

SELLER

1. Name of current certified owner ______________________
2. Mailing address ______________________
3. Business telephone number ______________________

GENERAL ORDERS – ELECTRIC RESELLER

PURCHASER ("Applicant")

4. Name of purchaser ____________________

5. Business mailing address of purchaser ____________________

   City and state ____________________ Zip code __________

6. Business telephone number __________ Business fax number __________

7. Business email address ____________________

UTILITY SERVICE AREA

8. Street Address of leased premises ____________________

9. Name of leased premises ____________________

10. County (or counties) ____________________

11. Supplier of purchased power ____________________

RESALE PROVISIONS

12. Describe the method Applicant proposes to use to allocate the supplier's individual electric bill for a unit among all the tenants in the unit (NCUC Rule R22-5):____________________

    ____

13. Monthly administrative fee per bill: ____________________

    (Pursuant to NCUC Rule R22-5(d), no more than $3.75 per month - the maximum amount authorized for water resellers by Commission Rule R18-6, may be added to the cost of electric service as an administrative fee. The amount of administrative fee, up to the maximum amount, should be justified by Applicant's actual costs.)

14. Bills will be past due ____ days after they are mailed or otherwise delivered to tenants. (NCUC Rule R22-7(e) specifies that bills shall not be past due less than twenty-five (25) days after mailing or other delivery to tenants.)

15. Late fee amount: ____________________

    (Pursuant to NCUC Rule R22-5(d) and (e), no more than 1% per month on the balance in arrears) Number of days after mailing or other delivery of bills at which the late fee begins to apply: _____ (See NCUC Rule R22-5(e) and (7)(e).)

16. Returned check charge: ____________________
    (Pursuant to NCUC Rule R22-5 and G.S. 25-3-506, no more than $25.00)

17. Statement of the Applicant's plans for retention and availability of records (see NCUC Rule R22-6(a) and (b)):

    ____

    ____

GENERAL ORDERS – ELECTRIC RESELLER

PERSONS TO CONTACT

	NAME	ADDRESS	TELEPHONE
18. Management	______	______ ______ Email ______	______
19. Complaints or Billing	______	______ ______ Email ______	______
20. Emergency Service	______	______ ______ Email ______	______
21. Filing and Payment of Regulatory Fees to Utilities Commission	______	______ ______ Email ______	______

OTHER PROVISIONS

22. Applicant must notify the Commission in writing within 30 days if any information supplied on this form changes in the future.

23. Applicant must also file quarterly Regulatory Fee Reports and make regulatory fee payments. Details are set out in NCUC Rule R15-1.

REQUIRED EXHIBITS

24. If the Purchaser is a corporation, LLC, LP, etc., enclose a copy of the certification from the North Carolina Secretary of State (Articles of Incorporation or Application for Certificate of Authority for Limited Liability Company, etc.). **(Must match name on Line 4 of application.)**

25. If the Purchaser is a partnership, enclose a copy of the partnership agreement. **(Must match name on Line 4 of application.)**

26. Enclose a copy of a Warranty Deed showing that the Purchaser has ownership of all the property necessary to operate the utility. **(Must match name on Line 4 of application.)**

27. Enclose a vicinity map showing the location of the leased premises in sufficient detail for someone not familiar with the county to locate the leased premises. (A county roadmap with the leased premises outlined is suggested.)

28. Enclose a copy of the supplier's schedule of rates that will be charged to the provider for purchased power.

29. Enclose a copy of any agreements or contracts the Applicant has entered into covering the provision of billing and collection services to the leased premises

30. Indicate the number of apartment buildings or residential buildings to be served, the number of units in each apartment building or residential building and the number of bedrooms in each unit.

31. Enclose a copy of the template form used for billing statements.

32. Enclose a copy (ies) of the form(s) used for leases to tenants, including a statement of which parts of the lease relate to billing for electrical services.

FILING INSTRUCTIONS

33. Submit one (1) original application with required exhibits and **original notarized signature**, plus seven (7) additional collated copies to: [USPS address] **Chief Clerk's Office, North Carolina Utilities Commission, 4325 Mail Service Center, Raleigh, North Carolina 27699-4325**, or [overnight delivery or hand delivery at street address] **Chief Clerk's Office, North Carolina Utilities Commission, 430 North Salisbury Street, Raleigh, North Carolina 27603.** Provide a self-addressed stamped envelope, plus an additional copy, if a file-stamped copy is requested by the Applicant.

34. Enclose a filing fee as required by G.S. 62-300. A Class A utility (annual electricity reseller revenues of $1,000,000 or more) requires a $250 filing fee. A Class B utility (annual electricity reseller revenues between $200,000 and $1,000,000) requires a $100 filing fee. A Class C utility (annual electricity reseller revenues less than $200,000) requires a $25 filing fee. **MAKE CHECK PAYABLE TO N.C. DEPARTMENT OF COMMERCE/UTILITIES COMMISSION.**

35. This application may be filed before title to the property passes to the new purchaser. In that event, the deed required in Item 26 above shall be filed with the Commission as a follow-up to the initial transfer application, once the deed has been executed and recorded with the Register of Deeds. The Commission may approve the transfer application with the condition that it is not effective until the deed is executed, recorded, and has been filed with the Commission.

SIGNATURES

36. Application shall be signed by an authorized representative of the seller.

Signature ______________________

Printed Name ______________________

Title ______________________

Date ______________________

37. Application shall be signed and verified by an authorized representative of the purchaser.

Signature ______________________

Printed Name ______________________

Title ______________________

Date ______________________

38. (Typed or printed name of the purchaser's representative) ______________________________

personally appearing before me and, being first duly sworn, says that the information contained in this application and in the exhibits attached hereto is true to the best of his/her knowledge and belief.

This the _______ day of _______________, 20 ____

____

Notary Public

My Commission Expires: ____________________

Date

(NOTARY SEAL)

(NCUC Docket No. ER-100, Sub 0, 04/19/2012; NCUC Docket No. ER-100, Sub 0, 03/31/14; NCUC Docket No. ER-100, Sub 0, ER-100, Sub 2, 07/20/2015 & 07/23/2015).

DOCKET NO. G-100, SUB 93

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petition for a Rulemaking Proceeding or the Implementation of a Cost Recovery Mechanism for Natural Gas Economic Development Infrastructure Pursuant to G.S. 62-133.15	)))))	ORDER ADOPTING FINAL RULE R6-96

BY THE COMMISSION: On October 6, 2017, the Public Staff filed a Petition for Rulemaking in the above-captioned docket. In summary, the Public Staff requested that the Commission adopt the Public Staff's proposed rule for implementation of the cost recovery mechanism authorized in G.S. 62-133.15.

On October 17, 2017, the Commission issued an Order Adopting Interim Commission Rule and Requesting Comments. The Order adopted the Public Staff's proposed Rule R6-96 on an interim basis, set a schedule for receipt of petitions to intervene, initial comments, and reply comments, and made Piedmont Natural Gas Company, Inc. (PNG), Public Service Company of North Carolina (PSNC), Frontier Natural Gas Company, LLC, Toccoa Natural Gas (Toccoa), and the North Carolina Attorney General's Office parties to this proceeding.

On October 25, 2017, the Carolina Utility Customers Association, Inc. (CUCA) filed a petition to intervene. On October 27, 2017, the Commission issued an Order granting the requested intervention by CUCA. On November 8, 2017, CUCA filed initial comments.

On November 9, 2017, Toccoa filed a response to the Commission's Order Requesting Comments.

On November 15, 2017, the Public Staff filed reply comments in response to CUCA's proposals in this docket.

SUMMARY OF COMMENTS

In its response, Toccoa advised the Commission that it is in agreement with the Public Staff's proposed rule.

In its comments, CUCA states that it supports economic development and the recruitment of new industry to North Carolina. In addition, CUCA requests that the Commission consider the interests of existing businesses across North Carolina.

CUCA states that if the revenue retention factor used in the calculation of the proposed rate adjustment surcharge (RAS) is equivalent to a margin decoupling mechanism, then industrial customers should be excluded from such a factor. In its reply comments, the Public Staff explains that CUCA conflated the revenue retention factor used in calculating the RAS with the margin decoupling mechanism. The Public Staff states that the revenue retention factor is used to gross up the expenses and return on investment and is specifically listed in G.S. 62-133.15(d)(4) as one of the costs recoverable in the mechanism.

In addition, CUCA opines that a strict reading of G.S. 62-133.15 does not indicate that the Commission is required to impose the RAS on all customer classes and, therefore, that the Commission should exempt industrial customers from paying the RAS. In its reply comments, the Public Staff explains that G.S. 62-133.15 does not provide that any particular class of ratepayers should be excluded from paying the RAS. Further, the Public Staff states that exempting a class of ratepayers from the RAS would be inconsistent with prior Commission orders.

CUCA also questions whether cost recovery would be allowed for new manufacturers that tap directly onto interstate pipelines, bypassing the natural gas local distribution company (LDC). In its reply comments, the Public Staff points out that G.S. 62-133.15 authorizes cost recovery only for LDCs that construct natural gas economic development infrastructure, not new manufacturers that tap directly into an interstate gas pipeline, and, therefore, the payment of a manufacturer's bypass costs will not occur under the statute.

Further, CUCA recommends that the Commission require the LDCs to list the RAS as a separate line item on customers' gas bills. CUCA contends that this will allow customers to know how much they are paying each month in higher gas bills to support economic development.

Finally, CUCA recommends that because the RAS will recover the costs of capacity related assets it should be in the form of a demand charge rather than a volumetric charge. However, the Public Staff notes that each of the LDC's interstate pipeline and storage capacity charges are recovered through volumetric rates and, therefore, RAS should be administered through a volumetric rate for all customer classes consistent with other approved riders in North Carolina.

The Public Staff states that it shared its reply comments with PNG and PSNC and they agree with its comments.

DISCUSSION AND CONCLUSIONS

G.S. 62-133.15 addresses the implementation of a cost recovery mechanism for an LDC that constructs natural gas economic development infrastructure to serve a project the North Carolina Department of Commerce determines is an eligible project under G.S. 143B-437.021. Pursuant to G.S. 62-133.15(a), the Commission is required to adopt rules implementing the statute. The Commission's interim Rule R6-96, adopted by Order issued October 17, 2017, established guidelines for applications by LDCs seeking cost recovery for the construction of natural gas development infrastructure under G.S. 62-133.15. After careful consideration of the comments filed in this proceeding, the Commission finds and concludes that its interim Rule R6-96 should be made permanent.

In response to the first issue raised by CUCA in its comments, the Commission agrees with the Public Staff that the revenue retention factor is specifically listed in G.S. 62-133.15(d)(4), and the revenue retention factor is different than the margin decoupling mechanism. The revenue retention factor is used to gross up the expenses and return on plant investment to cover such items as uncollectibles, regulatory fees, and taxes. In contrast, the margin decoupling mechanism is designed to allow the Company to track and true-up changes in its margins due to variations in average customer usage from levels approved in a general rate case.

The Commission also agrees with the Public Staff that G.S. 62-133.15 authorizes cost recovery for LDCs that construct natural gas economic development infrastructure, and does not address cost recovery for a manufacturer that chooses to bypass an LDC by connecting directly to an interstate pipeline. Therefore, CUCA's concern need not be addressed by the new rule.

Further, the Commission agrees with the Public Staff that G.S. 62-133.15 does not provide that any particular class of ratepayers should be excluded from payment of the RAS. If a class of ratepayers was exempted from the RAS, it would shift the costs of the infrastructure improvements between rate classes in a manner inconsistent with prior Commission Orders. Therefore, all LDCs should allocate the RAS to the rates of all customer classes, consistent with the intent of G.S. 62-133.15.

With regard to CUCA's recommendation that the Commission require the LDCs to list the RAS as a separate line item on customers' gas bills, the Commission declines to require this addition to the LDCs' bills. The RAS will be a relatively temporary rider compared to the integrity management riders (IMR) and customer usage tracker (CUT). The Commission previously has decided not to require separate line items for the IMR and CUT, in part due to a concern about information overload and bill clutter. Based on these same concerns, the Commission is not persuaded that it should require the LDCs to create a separate line item for the RAS.

The Commission also agrees with the Public Staff that the RAS should be administered through a volumetric rate for all customer classes consistent with other approved LDC riders in North Carolina.

Based upon the foregoing and the entire record in this proceeding, the Commission finds good cause to adopt interim Rule R6-96 as the final Rule, as set forth in Appendix A attached hereto.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 27th day of March, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

APPENDIX A

Article 15. Economic Development Infrastructure Cost Recovery

R6-96 NATURAL GAS ECONOMIC DEVELOPMENT INFRASTRUCTURE COST RECOVERY

(a) Purpose. – The purpose of this rule is to establish guidelines for applications of an LDC seeking cost recovery for the construction of natural gas development infrastructure under G.S. 62-133.15.

(b) Definitions. – As used in this section:

1. "Commission" means the North Carolina Utilities Commission.
2. "Economic development infrastructure" is the natural gas infrastructure placed in service to serve an eligible project.
3. "Economically infeasible" refers to that portion of investment in economic development infrastructure that has a negative net present value.
4. "Eligible economic development infrastructure costs" are the economically infeasible portion of an economic development infrastructure project investment.
5. "Eligible project" means a project that the Department of Commerce has designated as eligible under G.S. 143B-437.021.
6. "LDC" means a natural gas local distribution company.
7. "Net cash inflows" are the expected margin revenues, exclusive of gas costs recovered under G.S. 62-133.4, generated from the provision of natural gas service to Eligible Projects.
8. "Net cash outflows" are reasonable and prudent economic development infrastructure costs. Such costs include, but are not limited to, the following: (a) planning costs; (b) development costs; (c) construction costs and an allowance for funds used during construction and a return on investment once the project is completed, calculated using the pretax overall rate of return approved by the Commission in the LDC's most recent general rate case; (d) a revenue retention factor; (e) depreciation; and (f) property taxes.
9. "Net present value (NPV)" means the present value of expected future net cash inflows over the useful life of economic development infrastructure, minus the present value of net cash outflows.
10. "Rate adjustment surcharge (RAS)" is a yearly surcharge that allows an LDC to charge a Commission approved rate to recover the eligible economic development infrastructure costs.

(c) Application. – An application to recover eligible economic development infrastructure costs under this section shall contain all of the following information:

(1) Documentation showing the infrastructure is designed to serve an eligible project.

(2) A precise geographic description, a map or maps of the area proposed to be served, a detailed description of the proposed physical facilities, including their projected operating parameters and characteristics, and the arrangements that have been or are proposed to be made to obtain rights of-way.

(3) Documentation of a binding commitment from the prospective customer or the occupant of the eligible project to the LDC regarding the need to take natural gas service for a period of at least 10 years from the date the gas is made available.

(4) A market study, including an analysis of any potential customers and volumes, probable conversions from other fuels, and projected growth and economic development resulting from the infrastructure.

(5) An engineering study that includes the proposed design of the system (including a pipe network flow analysis), routing (including a review of planned or proposed state highway improvements), and construction cost estimates.

(6) An NPV analysis conducted in a generally accepted manner that provides support for the eligible economic development infrastructure costs.

(7) The estimated beginning and ending dates of the proposed construction of the infrastructure, including the date service to the eligible project is proposed to begin, and specific itemized construction budgets.

(8) Proposed rates to be charged under the RAS mechanism.

(d) Approval of Cost Recovery. – Once an eligible project has been approved by the Department of Commerce, the LDC may file an application with the Commission for authority to recover the estimated eligible economic development infrastructure costs.

(1) The Commission shall provide for notice of each request for approval filed under this Rule and shall afford an opportunity for review and comment by interested parties. The Commission shall set the request for hearing if it deems it appropriate.

(2) The Commission shall enter an order approving or denying the eligible economic development infrastructure costs on a project-specific basis. The order shall include a finding of the negative net present value of economic development infrastructure costs for each eligible project. The negative NPV is the maximum amount to be recovered through the RAS for an eligible project.

(3) The LDC may request modifications to eligible economic development infrastructure costs approved by the Commission. If the Commission finds the requested change is material, the Commission shall provide for appropriate notice and shall afford an opportunity for review and comment by interested parties. The Commission shall set the proposal for hearing if it deems it appropriate.

(e) Cost Recovery. – Once economic development infrastructure is placed in service, the LDC may recover the economic development infrastructure costs approved by the Commission in an annual RAS. The RAS will terminate upon the earlier of the full recovery of the approved economic development infrastructure costs, or the effective date of rates in the LDC's next general rate case, provided that the underlying infrastructure investment is included in calculating such rates.

(f) Computation of the economic development infrastructure revenue requirement. – The LDC shall file information for each year showing the computation of the Economic Development Infrastructure revenue requirement. The total annual revenue requirement will be calculated for each year, as follows:

Economic Development Infrastructure Costs	$X,XXX,XXX
Less: Accumulated depreciation	XXX,XXX
Less: Accumulated deferred income taxes	XXX,XXX
Net Economic Development Infrastructure Costs	$X,XXX,XXX
Pre-tax rate of return set forth in the relevant rate order	X.XX%
Allowed pre-tax return	$X,XXX,XXX
Plus: Depreciation expense	XXX,XXX
Total	$X,XXX,XXX

(g) Computation of the RAS. – The LDC will file for Commission approval each year information showing the computation of the RAS for each rate schedule and the revised tariffs that it proposes to charge customers during the 12-month period. To compute the RAS, the Economic Development Infrastructure revenue requirement shall first be apportioned to each customer class based on margin apportionment established in the LDC's most recent general rate case.

The amount of the economic development infrastructure revenue requirement apportioned to each rate schedule shall then be divided by the annual therms established in the LDC's most recent general rate case proceeding for each rate schedule to determine the RAS to the nearest one-thousandth cent per therm.

(h) RAS Deferred Account. – The LDC shall maintain an RAS Deferred Account for the purpose of recording (1) the economic development infrastructure revenue requirement for the year (2) the monthly RAS collected from customers, and (3) the interest on the RAS Deferred Account. Interest will be applied to the RAS Account at the LDC's authorized net-of-tax overall rate of return.

Each month the LDC shall credit the RAS Deferred Account for the amount of the RAS collected from customers. The amount of the RAS collected from customers shall be computed by multiplying the RAS for each rate schedule by the corresponding actual therms of usage billed customers for the month.

(i) Reports. – Each LDC with an approved RAS shall provide the following reports to the Commission:

1. Monthly RAS Deferred Account reports reflecting the activity recorded for the month.

2. Annual RAS Deferred Account report to recover the balance in the account and an annual computation of the Economic Development Infrastructure revenue requirement supporting the RAS for the next 12-month period.
3. Annual reports by March 1 of each year the Eligible Project is under construction summarizing the total infrastructure costs for the preceding calendar year, the remaining balance to be spent on total infrastructure costs, and the estimated completion date of the infrastructure.
4. Annual reports by March 1 of each year for completed Eligible Projects, providing the total amounts recovered from the RAS for each project, the amount of gas consumed each year for each project, and all customer additions and the respective natural gas load for each project. Annual reports on completed eligible projects are required until the LDC's next general rate case.

GENERAL ORDERS – NATURAL GAS RESELLER

DOCKET NO. GR-100, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Rulemaking to Implement North Carolina	)	ORDER ADOPTING
Session Law 2017-172 (House Bill 799)	)	FINAL RULES AND FORMS

BY THE COMMISSION: On July 21, 2017, House Bill 799 (S.L. 2017-172) was enacted into law. This legislation, entitled "An Act to Allow for Landlords to Charge Individual Tenants for Shared Cost of Natural Gas Service Provided to Leased Premises," authorizes in G.S. 62-110(i) for lessors of a single-family dwelling, residential building, or multiunit apartment complex that has individually metered units for natural gas service in the lessor's name to charge for the actual costs of providing natural gas service to each lessee. House Bill 799 outlines the provisions that apply to the natural gas service charges so authorized and requires the Commission to adopt rules to implement the legislation and to develop an application that lessors must submit for Commission approval to obtain a certificate to resell natural gas service. In addition, House Bill 799 modified certain terminology used in G.S. 42-42.1, Water, Electricity, and Natural Gas Conservation.

On November 7, 2018, the Commission issued an Order Initiating Rulemaking Proceeding to adopt rules to regulate the reselling of natural gas service consistent with the General Assembly's directive. In that Order, the Commission adopted on an interim basis: (1) the Rules and Regulations in Chapter 24 – Provision of Natural Gas Service by Lessors, (2) Form GR-1: Application for Certificate of Authority to Resell Natural Gas Service, and Form GR-2: Application for Transfer of Authority to Resell Natural Gas Service. That Order also set a schedule for receipt of petitions to intervene, initial comments, and reply comments. Finally, that Order made Piedmont Natural Gas Company, Inc. (PNG), Public Service Company of North Carolina (PSNC), Frontier Natural Gas Company, LLC, and Toccoa Natural Gas, parties to this proceeding. A copy of that Order was served upon the North Carolina Attorney General's Office, the North Carolina Justice Center, and the Apartment Association of North Carolina.

On November 29, 2017, PSNC and PNG filed initial comments. No other filings were submitted in this proceeding.

SUMMARY OF COMMENTS

In its comments, PSNC states that it does not have any objections to the interim Rules and Regulations of Chapter 24, Form GR-1, or Form GR-2.

In its comments, PNG requests that the Commission affirm that the adoption of Chapter 24 "will not in any material way, change, disrupt or impact the metering and billing practices of [PNG] with respect to natural gas distribution service provided to individually metered 'units' within a provider's multiunit apartment complex, residential building, or single-family home – except to the extent that bills for such service shall be aggregated and transmitted to the provider for payment in lieu of delivery to individual customers within such units." Such affirmation, according to PNG, is necessary to ensure that PNG and its customers are held harmless by the implementation of flow-through billing, as contemplated by House Bill 799 and the Rules and Regulations of Chapter 24.

In addition, PNG states that revisions to its existing tariffs and rate schedules are needed as a result of the legalization of the reselling of natural gas service by lessors. For example, PNG's current tariffs and rate schedules expressly prohibit the resale of natural gas service. As a result, PNG requests that the Commission "acknowledge the need for such conforming tariff filings to be made and approved before the flow-through billing regimen anticipated by Chapter 24 is fully implemented."

Finally, PNG provides several suggested modifications to the Commission's interim Rules and Regulations of Chapter 24, including that: (1) the term "unit" should be defined, although PNG did not propose a definition for the same; (2) a consolidated definition for the term "provider," which could subsume other defined terms, including "landlord" and "lessor," is needed; and (3) the term "leased premises" should be defined, although PNG also did not propose a definition for this term.

DISCUSSION AND CONCLUSIONS

After initiating this rulemaking proceeding, issuing on an interim basis the Rules and Regulations of Chapter 24, Form GR-1, and Form GR-2 and receiving comments from interested parties, the Commission finds good cause to issue this Order adopting final rules and forms. In so doing, the Commission endeavored to give full effect to the intent of the Legislature as evidenced through the plain language of House Bill 799. The Commission also attempted, where possible, to ensure consistency between the regulatory processes for the reselling of electric service and natural gas service. The Commission carefully considered the few comments received in this proceeding and responds accordingly below. The Commission also raises a few issues not addressed by any party to this proceeding.

Issues Raised by PNG

The Commission notes that PNG is correct in its assessment that the Rules and Regulations of Chapter 24 provide for a flow-through billing mechanism, through which a non-wholesale customer of the gas public utility may resell natural gas service in a manner consistent with applicable law and Commission Rules.

The Commission also recognizes that PNG, as well as other gas public utility companies, as necessary, may need to revise their current tariff and rate schedule language to ensure consistency with newly enacted laws and Commission Rules. The Commission does not, however, agree with PNG that the implementation of the Rules and Regulations of Chapter 24 should be delayed until such time as a tariff revision may be applied for and approved by the Commission. The Rules and Regulations of Chapter 24 were adopted on an interim basis on November 8, 2017 and already have been in effect since that date. As such, the Commission does not deem it necessary or appropriate to delay the final adoption of the Rules and Regulations of Chapter 24 to allow for any proposed tariff revisions, as necessary, to be reviewed by the Commission and implemented. Instead, the Commission directs any gas public utility that must, as a result of the adoption of the Rules and Regulations of Chapter 24, apply for revisions to its existing tariffs or rate schedules to do so by filing such requests both in this proceeding and in a separate company-specific proceeding.

With regard to PNG's suggested revisions to the interim Rules and Regulations of Chapter 24, the Commission notes that PNG's suggestions largely were not substantive in nature. In response to PNG's concern that the term "leased premises" is used throughout Chapter 24 without a corresponding definition in the rules, the Commission agrees and has modified accordingly its definitions of "multiunit apartment complex," "residential building," and "single-family dwelling" to clarify that a "leased premises" is synonymous and may be used interchangeably to refer to one or more multiunit apartment complex, residential building, or single-family dwelling.

In response to PNG's suggestion that a definition for the term "unit" is needed, the Commission notes that PNG did not explain its rationale for this suggestion. After reviewing the statutory changes effectuated by the passage of House Bill 799 in the context of the interim definitions adopted, the Commission disagrees with PNG that a definition for the term "unit" would make the Rules and Regulations of Chapter 24 any more precise or clearer. The Commission likewise disagrees with PNG's suggestion to subsume into the definition of "provider" the terms "landlord" and "lessor." The Commission notes that, while a provider must also be a lessor pursuant to Chapter 24, a lessor is not necessarily or automatically considered to be a provider. The Commission, therefore, declines to adopt this recommendation. In addition, the Commission similarly declines to refer to a "lessor" as a "landlord," on the grounds that it would be inconsistent with legislative intent, as evidenced in House Bill 799 through the replacement in multiple places of the term "landlord" in favor of the term "lessor."

Issues Not Raised by the Parties in the Instant Proceeding

The Commission notes that the Public Staff, in Docket No. WR-100, Sub 10, suggested in its comments to include in the rules governing water and/or sewer service resellers appropriate language to ensure that lessees do not have to travel unreasonable distances to examine the records pertaining to their accounts. In that proceeding, the Public Staff opined that an organization in the business of leasing single-family dwellings on a nationwide basis may have only a single business office in North Carolina; nonetheless, a lessee renting a residence in Murphy should not be required to travel to the lessor's business office in Raleigh or Charlotte to view his or her water and/or sewer service account records. Though the Public Staff did not file comments in the instant proceeding, the Commission finds that the concern expressed by the Public Staff in Docket No. WR-100, Sub 10 is similarly applicable to the instant proceeding. Therefore, the Commission finds good cause to modify substantively interim Rule 24-6(b), as reflected in the final Rules attached to this Order, consistent with the changes recently adopted in Rule R18-5(a).[1]

The Commission also notes that the Public Staff, in Docket No. ER-100, Sub 4, suggested in its comments to amend the rules governing electric service resellers by adding the following underlined sentence to Rule 22-4(b):

[1] See Order Adopting Final Rules and Forms, Docket No. WR-100, Sub 10 (April 4, 2018).

(b) An applicant may submit for authority to charge for electric service for more than one property in a single application. Information relating to all properties covered by the application need only be provided once in the application. <u>However, if any of the information required by the application differs for different properties, the differences must be clearly explained.</u>

The Public Staff recommended the modification to Rule R22-4(b) "so that it can be discerned if all the properties listed in the application comply with the rules and regulations." Because the natural gas reseller rules also provide for the option to submit a single application for more than one property, the Commission finds that the suggestion expressed by the Public Staff in the context of electric service reseller rules is similarly applicable to the instant proceeding. Therefore, the Commission finds good cause to modify substantively interim Rule 24-4(b), as reflected in the final Rules attached to this Order, consistent with the Public Staff's recommendation in Docket No. ER-100, Sub 4.

While in the process of reviewing and modifying the interim Rules and Forms, the Commission notes that a number of formatting, typographical, and other minor corrections are necessary to ensure that accurate information about the resale of natural gas service is provided to both lessors and lessees. For example, the Commission corrected the telephone number information in Rule 24-7(g)(3) to reflect that the Public Staff's Consumer Services Division's toll-free number may be utilized by both out-of-state and in-state callers. The Commission, therefore, finds good cause to make these and other such changes, as reflected in the final Rules and Forms attached to this Order.

Finally, while in the process of reviewing and modifying existing rules governing the electric resellers, the Commission notes that a number of changes are necessary to ensure consistency, where possible, between the rules and forms governing electric resellers and those governing natural gas resellers. The Commission, therefore, finds good cause to make such revisions, as reflected in the final Rules and Forms attached to this Order.

Based upon the foregoing and the entire record in this proceeding, the Commission adopts as final the Rules and Regulations of Chapter 24, as set forth in Appendix A to this Order; Form GR-1, as set forth in Appendix B to this Order; and Form GR-2, as set forth in Appendix C to this Order.

IT IS, THEREFORE, ORDERED as follows:

1. That the Rules and Regulations of Chapter 24 – Provision of Natural Gas Service by Lessors, attached to this Order as Appendix A; Form GR-1: Application for Certificate of Authority to Resell Natural Gas Service, attached to this Order as Appendix B; and Form GR-2: Application for Transfer of Authority to Resell Natural Gas Service, attached to this Order as Appendix C are hereby promulgated and supersede the existing Interim Rules and Forms adopted by the Commission in its November 8, 2017 Order;

2. That any natural gas public utility which must propose revisions to its existing tariffs or rate schedules as a result of the adoption of the Rules and Regulations of Chapter 24 shall

do so by filing the requested revisions both in this proceeding and in a separate company-specific proceeding; and

3. That the Chief Clerk shall serve a copy of this Order on every party to this proceeding, the Public Staff, and the Attorney General's Office.

ISSUED BY ORDER OF THE COMMISSION.
This the 6th day of April, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

APPENDIX A

CHAPTER 24.
PROVISION OF NATURAL GAS SERVICE BY LESSORS.

Rule R24-1. APPLICATION.

Pursuant to G.S. 62-110(i), this Chapter governs the resale of natural gas by a lessor of a single-family dwelling, residential building, or multiunit apartment complex that has individually metered units for natural gas service in the lessor's name, where the lessor charges the actual costs of providing natural gas service to each lessee.

Rule R24-2. DEFINITIONS.

(a) *Lessee.* A person who purchases natural gas service from a provider.

(b) *Lessor.* A person, entity, corporation, or agency who owns a residential building, single-family dwelling, or multiunit apartment complex which is available for lease.

(c) *Multiunit apartment complex.* Premises where one or more buildings containing multiple residential dwelling units under common ownership are available for rent to lessees. One or more multiunit apartment complexes may be known as the leased premises.

(d) *Provider.* A lessor who purchases natural gas service from a supplier and charges for the costs of providing the service to lessees. A provider must be the owner of the premises served.

(e) *Residential building.* A townhouse, row house, condominium, mobile home, building, or other structure used for residential purposes. One or more residential buildings may be known as the leased premises.

(f) *Single-family dwelling.* An individual, freestanding, unattached dwelling unit, typically built on a lot larger than the structure itself, resulting in an area surrounding the house known as a yard, which is rented or available for rental as a residence. One or more single-family dwellings may be known as the leased premises.

(g) *Supplier.* A public utility or an agency or organization exempted from regulation from which a provider purchases natural gas service.

APPENDIX A

(h) *Supplier's Unit Natural Gas Service Bill.* The actual amount charged by the supplier for the unit as a whole less any amount charged by the supplier that is not recoverable from the lessees, such as connection or disconnection charges, provider late fees, or amounts attributed to excess usage as provided in Rule R24-7(f).

(i) *Common Area.* The parts of the rental property that are not otherwise leased to tenants and that are available to or otherwise accessible to all tenants.

Rule R24-3. UTILITY STATUS; CERTIFICATE.

(a) Every provider is a public utility as defined by G.S. 62-3(23)a.1. and shall comply with and be subject to all applicable provisions of the Public Utilities Act and all applicable rules and regulations of the Commission, except as hereinafter provided.

(b) A provider who charges for natural gas service under this Rule:
- (1) is solely responsible for the prompt payment of all bills rendered by the supplier and is the retail customer of the supplier subject to all rules, regulations, tariffs, riders, and service regulations associated with the provision of residential natural gas service to retail customers of the supplier; and
- (2) is not considered a wholesale customer of the supplier.

(c) No provider shall begin charging for the costs of providing natural gas service prior to applying for and receiving a certificate of authority from the Commission.

Rule R24-4. APPLICATION FOR AUTHORITY.

(a) Every application for authority to charge for the costs of providing natural gas service shall be in such form and detail as the Commission may prescribe and shall include:

(1) a description of the lessor, who is the applicant, including legal name and type of business entity, and a description of the property to be served, including business or marketing name, if any, street address, and number of units;
(2) a description of the proposed billing method and billing statements;
(3) the proposed method of allocating the supplier's charges to the lessees;
(4) the administrative fee per lessee, returned check charge, and late payment charge, if any, proposed to be charged by the applicant, and the number of days after the bill is mailed or otherwise delivered when the late payment fee would begin to be applied;
(5) the applicant's plans for retention and availability of records;
(6) the name of and contact information for the applicant and its agents, including mailing address, email address, and telephone number;

APPENDIX A

(7) the name of and contact information for the supplier of natural gas service to the applicant's rental property;
(8) the current schedule of charges from the supplier;
(9) a copy of the lease forms to be used by the applicant for lessees who are billed for natural gas service pursuant to this Chapter;
(10) a statement indicating the particular provisions of the lease forms pertaining to billing for natural gas service;
(11) the verified signature of the applicant or applicant's authorized representative;
(12) the required filing fee;
(13) one (1) original and seven (7) collated copies of the application; and
(14) any additional information that the Commission may require.

(b) An applicant may submit for authority to charge for natural gas service for more than one property in a single application. Information relating to all properties covered by the application need only be provided once in the application. However, if any of the information required by the application differs for different properties, the differences must be clearly explained.

(c) The Commission shall approve or disapprove an application within 60 days of the filing of a completed application with the Commission. If the Commission has not issued an Order disapproving a completed application within 60 days, the application shall be deemed approved; provided, however, no person or entity may charge for natural gas service in a manner inconsistent with Chapter 62 of the North Carolina General Statutes.

(d) An approved certificate of authority from the Commission to charge for the costs of providing natural gas service under these rules shall be delivered to the supplier from which the provider purchases natural gas service and include information in Rule R24-4(a)(1) and (6).

Rule R24-5. BILLS OF THE PROVIDER.

(a) Bills for natural gas service sent by the provider to the lessee shall contain all of the following information:

(1) the Supplier's Unit Natural Gas Service Bill for the unit as a whole and the amount of charges allocated to the lessee during the billing period;
(2) the name of the supplier;
(3) the beginning and ending dates for the usage period and, if provided by the supplier, the date the meter for the unit was read for that usage period;
(4) the past-due date, which shall not be less than 25 days after the bill is mailed or otherwise delivered to the lessee;

(5) the name of the provider and a local or toll-free telephone number and address of the provider that the lessees can use to obtain more information about the bill;
(6) the amount of administrative fee, returned check charge, and the late payment charge approved by the Commission and included in the bill, if any; and
(7) a statement of the lessee's right to address questions about the bill to the provider and the lessee's right to file a complaint with, or otherwise seek recourse from, the Commission if the lessee cannot resolve a natural gas service billing dispute with the provider.

(b) The provider or the provider's billing agent shall equally divide the actual amount of the Supplier's Unit Natural Gas Service Bill for a unit among all the lessees in the unit and shall send one bill to each lessee.

(c) The amount charged shall be prorated when a lessee has not leased the unit for the same number of days as the other lessees in the unit during the billing period.

(d) Each bill may include an administrative fee no greater than the amount authorized in Rule R18-6 for water service and, when applicable, a late payment charge no greater than the amount authorized in Rule R12-9(d) and a returned check charge no greater than the amount authorized in G.S. 25-3-506.

(e) A late payment charge may be applied to the balance in arrears after the past-due date.

(f) The provider may impose a returned check charge, not to exceed the maximum authorized by G.S. 25-3-506, for a check on which payment has been refused by the payor bank because of insufficient funds or because the lessee did not have an account at that bank.

(g) The provider shall not charge the cost of natural gas from any other unit or common area in a lessee's bill.

(h) No provider shall charge or collect any greater compensation for the costs of providing natural gas service than the rates approved by the Commission.

(i) The provider may, at the provider's option, pay any portion of any bill sent to a lessee, in accordance with the provisions of the lease; provided, however, that (1) the provider must still send each lessee bills in accordance with the other provisions in Rule R24-5; (2) the provider must credit lessee bills or otherwise refund to lessees the amount, if any, by which the amount specified in the lease exceeds the amount actually owed by the lessee for natural gas usage in the immediately preceding month; and (3) the provider must comply with G.S. 62-140 regarding non-discrimination in billing for utility service.

APPENDIX A

Rule R24-6. RECORDS, REPORTS AND FEES.

(a) The provider shall maintain for a minimum of 36 months records that demonstrate how each lessee's allocated costs were calculated for natural gas service, as well as any other natural gas service-related fees charged to each lessee.

(b) All records required to be maintained by the provider pursuant to section (a) shall be kept at the onsite management office or office(s) of the provider in North Carolina, or shall be made available at its onsite management office in North Carolina upon request, and shall be available during regular business hours for examination by the Commission or Public Staff or their duly authorized representatives. Within three business days after a written request to the provider, a lessee may examine the records pertaining to the lessee's account during regular business hours and may obtain a copy of those records at a reasonable cost, which shall not exceed 25¢ per page. However, if a provider does not have an onsite management office at the multi-unit complex or in close proximity to the leased single-family dwelling, then the provider shall in good faith, upon written request, establish with the lessee a mutually-acceptable arrangement for the lessee to examine the records pertaining to the natural gas service for the leased dwelling unit occupied or previously occupied by the lessee. In the event that a provider and lessee are unable to reach agreement within 10 business days, the lessee may contact the Public Staff – North Carolina Utilities Commission, Consumer Service Division, at (866) 380-9816 (toll-free) or (919) 733-9277, or may write to the Public Staff – North Carolina Utilities Commission, Consumer Services Division, at 4326 Mail Service Center, Raleigh, North Carolina 27699-4300 for assistance in resolving the dispute. If the Public Staff determines that it cannot reasonably resolve the disagreement, the matter shall be referred to the Commission.

(c) Providers shall not be required to file an annual report to the Commission as required by Rule R1-32.

(d) Providers shall pay a regulatory fee and file a regulatory fee report as required by Rule R15-1.

(e) Special reports shall also be made concerning any particular matter upon request by the Commission.

Rule R24-7. DISCONNECTION; BILLING PROCEDURE.

(a) Any payment to the provider shall be applied first to the rent owed and then to charges for natural gas service, unless otherwise designated by the lessee.

(b) No charge for connection or disconnection or late fee or deposit paid by the provider to the supplier shall be allowed, and no provider may terminate a lease for nonpayment of natural gas service.

APPENDIX A

(c) No provider may disconnect or request the supplier to disconnect natural gas service for the lessee's nonpayment of a bill.

(d) Bills shall be rendered at least monthly.

(e) The date after which a bill for natural gas service is due (the past-due date) shall be disclosed on the bill and shall not be less than twenty-five (25) days after the bill is mailed or otherwise delivered to the lessee.

(f) A provider shall not bill for or attempt to collect for excess usage resulting from a meter malfunction or other natural gas condition in appliances such as water heaters, HVAC systems, or ranges furnished by the provider to the lessee, when the malfunction is not known to the lessee or when the malfunction has been reported to the provider.

(g) Every provider shall provide to each lessee at the time the lease agreement is signed, and shall maintain in its business office, in public view, near the place where payments are received, the following:

(1) A copy of the rates, rules, and regulations of the provider applicable to the premises served from that office, with respect to natural gas service;
(2) A copy of these rules and regulations (Chapter 24); and
(3) A statement advising lessees that they should first contact the provider's office with any questions they may have regarding bills or complaints about service, and that in cases of dispute, they may contact the Commission either by calling the Public Staff - North Carolina Utilities Commission, Consumer Services Division, at (866) 380-9816 (toll-free) or (919) 733-9277, or by appearing in person or writing to the Public Staff - North Carolina Utilities Commission, Consumer Services Division, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300.

(h) Each provider shall adopt a means of informing its lessees initially and on an annual basis as to the provider's method of allocating bills to the individual lessees and its administrative fee, returned check charge, and late fee, if any. A copy of the supplier's current schedule of charges shall also be included in these disclosures.

(i) Every provider shall promptly notify the Commission in writing of any change in the information required in Rule R24-4(a), except for changes in the rates and charges of the supplier (Rule R24-4(a)(8)).

(j) If a provider anticipates that it will not pay a supplier's bill on time, or if the provider receives notice from the supplier of pending disconnection, whichever comes first, the provider must within 24 hours provide written notice to the Commission and all of the provider's affected lessees of the anticipated nonpayment or disconnection notice. A provider may not abandon or cease providing natural gas service to its lessees without advance permission from the Commission.

GENERAL ORDERS – NATURAL GAS RESELLER

FORM GR-1
4/2018

APPENDIX B

CHAPTER 24.
APPENDIX.

DOCKET NO. GR-________,SUB ______

FILING FEE RECEIVED ____________

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

APPLICATION FOR CERTIFICATE OF AUTHORITY TO RESELL NATURAL GAS SERVICE IN ACCORDANCE WITH G.S. 62-110(i) and NORTH CAROLINA UTILITIES COMMISSION CHAPTER 24

INSTRUCTIONS

If additional space is needed, supplementary sheets may be attached. If any section does not apply, write "not applicable."
Utility laws, the Commission's Rules, and other information may be accessed at http://www.ncuc.net/index.htm

APPLICANT

1. Name of owner: ____________
(Individual name if the owner is a sole proprietor or business name if not a sole proprietor.)
2. Type of Business Entity: ____________
3. Business mailing address of owner: ____________
City and state: ____________ Zip code: ________
4. Business telephone number: ____________ Business fax number: ________
5. Business email address: ____________
6. Person to Contact Concerning this Application (Name, Telephone, and Email):

____

PROPOSED UTILITY SERVICE AREA
(Attach additional sheets if more than one property)

7. Name of Single-Family Dwelling, Residential Building, or Apartment Complex (hereinafter leased premises):____________
8. Street Address of leased premises: ____________
9. County: ____________
10. Name, address and telephone number of the supplier of natural gas: ____________

____
11. Number of lessees that can be served at this leased premises: ____________

GENERAL ORDERS – NATURAL GAS RESELLER

RESALE PROVISIONS

12. Describe the method Applicant proposes to use to allocate the supplier's individual natural gas bill for a unit among all the lessees in the unit (NCUC Rule R24-5): (Note: if it is a single-family dwelling or residential building, there may be no allocation method): ____________________
____

13. Monthly administrative fee per bill: ____________________
(Pursuant to NCUC Rule R24-5(d), no more than $3.75 per month, the maximum amount authorized for water resellers by NCUC Rule R18-6, may be added as an administrative fee to the cost of natural gas service. The amount of the administrative fee, up to the maximum amount, should be justified by Applicant's actual costs.)

14. Bills will be past due ____ days after they are mailed or otherwise delivered to lessees. (NCUC Rule R24-7(f) specifies that bills shall not be past due less than twenty-five (25) days after mailing or other delivery to lessees.)

15. Late fee amount: ________ (Pursuant to NCUC Rule 24-5(d) and (e), a late fee of no more than 1% per month of the balance in arrears may be assessed.)

16. Returned check charge: _________ (Pursuant to NCUC Rule 24-5(f) and G.S. 25-3-506, a returned check fee of no more than $25.00 may be assessed.)

17. Statement of Applicant's plans for retention and availability of records (see NCUC Rule R24-6(a) and (b)): _
____
____

PERSONS TO CONTACT

		NAME	ADDRESS	TELEPHONE
18.	Management:	________	________ ________ Email ________	________
19.	Complaints or Billing:	________	________ ________ Email ________	________
20.	Emergency Service:	________	________ ________ Email ________	________
21.	Filing and Payment of Regulatory Fees to NCUC:	________	________ ________ Email ________	________

OTHER PROVISIONS

22. Applicant must notify the Commission in writing within 30 days following the change of any information supplied on this form.

23. Applicant must also file quarterly Regulatory Fee Reports and make regulatory fee payments. Details are set out in NCUC Rule R15-1.

REQUIRED EXHIBITS

24. If Applicant is a corporation, LLC, LP, or other legal business entity, enclose a copy of the certification from the North Carolina Department of the Secretary of State (Articles of Incorporation or Application for Certificate of Authority for Limited Liability Company, etc.). **(Must match name on Line 1 of application.)**

25. If Applicant is a partnership, enclose a copy of the partnership agreement. **(Must match name on Line 1 of application.)**

FORM GR-1
4/2018 **APPENDIX B**

26. Enclose a copy of a Warranty Deed showing that the Applicant has ownership of all the property necessary to operate the utility. **(Must match name on Line 1 of application.)**

27. Enclose a vicinity map showing the location of the leased premises in sufficient detail for someone not familiar with the county to locate the leased premises. (A county roadmap with the leased premises outlined is suggested.)

28. Enclose a copy of the supplier's schedule of rates that will be charged to the Applicant for natural gas service.

29. Enclose a copy of any agreements or contracts that Applicant has entered into covering the provision of billing and collections services to the leased premises.

30. Indicate the number of apartment buildings, residential buildings, or single-family dwellings to be served, the number of units in each apartment building or residential building, and the number of bedrooms in each unit.

31. Enclose a copy of the template or form used for billing statements.

32. Enclose a copy of all forms used for the lease to lessees, including a statement of which parts of the lease relate to billing for natural gas service.

FILING INSTRUCTIONS

33. Electronic filing is available at www.ncuc.net for application submittal, or mail one (1) original application with required exhibits and original **notarized signature**, plus three (3) additional collated copies to:

USPS Address:	OR	Overnight Delivery at Street Address:
Chief Clerk's Office North Carolina Utilities Commission 4325 Mail Service Center Raleigh, North Carolina 27699-4300		Chief Clerk's Office North Carolina Utilities Commission 430 North Salisbury Street Raleigh, NC 27603-5918

GENERAL ORDERS – NATURAL GAS RESELLER

34. Enclose a filing fee as required by G.S. 62-300. A Class A utility (annual natural gas reseller revenues of $1,000,000 or more) requires a $250 filing fee. A Class B utility (annual natural gas reseller revenues between $200,000 and $1,000,000) requires a $100 filing fee. A Class C utility (annual natural gas reseller revenues less than $200,000) requires a $25 filing fee. **MAKE CHECK PAYABLE TO N.C. DEPARTMENT OF COMMERCE/UTILITIES COMMISSION.**

SIGNATURE

35. Application shall be signed and verified by an authorized representative of Applicant.

Signature: ______________________

Printed Name: ______________________

Title: ______________________

Date: ______________________

36. (Typed or Printed Named) ______________________, personally appearing before me and, being first duly sworn, says that the information contained in this application and in the exhibits attached hereto is true to the best of his/her knowledge and belief.

This the ________ day of ______________, 20_____

____
Signature of Notary Public

____
Name of Notary Public – Typed or Printed

My Commission Expires: ______________________
Date

(NOTARY SEAL)

FORM GR-2
4/2018

APPENDIX C

SELLER DOCKET NO. GR-______________
PURCHASER DOCKET NO. GR-______________
FILING FEE RECEIVED GR-______________

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

APPLICATION FOR TRANSFER OF AUTHORITY TO RESELL NATURAL GAS SERVICE FOR LEASED PREMISES

INSTRUCTIONS

If additional space is needed, supplementary sheets may be attached. If any section does not apply, write "not applicable"

GENERAL ORDERS – NATURAL GAS RESELLER

SELLER

1. Name of current certified owner: ____________________
2. Mailing address: ____________________
3. Business telephone number: ____________________

PURCHASER ("Applicant")

4. Name of purchaser: ____________________
5. Business mailing address of purchaser: ____________________

   City and state: ____________________ Zip code: __________

6. Business telephone number: ____________________ Business fax number: __________
7. Business email address: ____________________

UTILITY SERVICE AREA

8. Street Address of Leased Premises: ____________________
9. Name of Leased Premises: ____________________
10. County (or counties): ____________________
11. Supplier of natural gas ____________________

RESALE PROVISIONS

12. Describe the method Applicant proposes to use to allocate the supplier's individual natural gas bill for a unit among all the lessees in the unit (NCUC Rule R24-5): ____________________
13. Monthly administrative fee per bill: ____________________

    (Pursuant to NCUC R24-5(d), no more than $3.75 per month, the maximum amount authorized for water resellers by Commission Rule R18-6, may be added as an administrative fee to the cost of natural gas service. The amount of the administrative fee, up to the maximum amount, should be justified by Applicant's actual costs.)

14. Bills will be past due____ days after they are mailed or otherwise delivered to lessees. (NCUC Rule R24-7(e) specifies that bills shall not be past due less than twenty-five (25) days after mailing or other delivery to lessees.)
15. Late fee amount: ____________________

    (Pursuant to NCUC Rule R24-5(d) and (e), no more than 1% per month on the balance in arrears may be assessed.)

16. Returned check charge:____________________
(Pursuant to NCUC Rule R24-5 and G.S. 25-3-506, no more than $25.00.)

17. Statement of Applicant's plans for retention and availability of records (see NCUC Rule R24-6(a) and (b)):
____
____

PERSONS TO CONTACT

	NAME	ADDRESS	TELEPHONE
18. Management:	________	________ ________ Email ________	________
19. Complaints or Billing:	________	________ ________ Email ________	________
20. Emergency Service:	________	________ ________ Email ________	________
21. Filing and Payment of Regulatory Fees to NCUC:	________	________ ________ Email ________	________

OTHER PROVISIONS

22. Applicant must notify the Commission in writing within 30 days following the change of any information supplied on this form.
23. Applicant must also file quarterly Regulatory Fee Reports and make regulatory fee payments. Details are set out in NCUC Rule R15-1.

REQUIRED EXHIBITS

24. If the Purchaser is a corporation, LLC, LP, etc., enclose a copy of the certification from the North Carolina Secretary of State (Articles of Incorporation or Application for Certificate of Authority for Limited Liability Company, etc.). **(Must match name on Line 4 of application.)**
25. If the Purchaser is a partnership, enclose a copy of the partnership agreement. **(Must match name on Line 4 of application.)**
26. Enclose a copy of a Warranty Deed showing that the Purchaser has ownership of all the property necessary to operate the utility. **(Must match name on Line 4 of application.)**
27. Enclose a vicinity map showing the location of the leased premises in sufficient detail for someone not familiar with the county to locate the leased premises. (A county roadmap with the leased premises outlined is suggested.)

GENERAL ORDERS – NATURAL GAS RESELLER

28. Enclose a copy of the supplier's schedule of rates that will be charged to the Applicant for natural gas.

29. Enclose a copy of any agreements or contracts that the Applicant has entered into covering the provision of billing and collections services to the leased premises.

30. Indicate the number of apartment buildings, residential buildings, or single-family dwellings to be served, the number of units in each apartment building or residential building and the number of bedrooms in each unit.

31. Enclose a copy of the template or form used for billing statements.

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APPENDIX C

32. Enclose a copy of all forms used for the lease to lessees, including a statement of which parts of the lease relate to billing for natural gas service.

FILING INSTRUCTIONS

33. Electronic filing is available at www.ncuc.net for application submittal or mail one (1) original application with required exhibits and original **notarized signature**, plus three (3) additional collated copies to:

USPS Address:	OR	Overnight Delivery at Street Address:
Chief Clerk's Office North Carolina Utilities Commission 4325 Mail Service Center Raleigh, North Carolina 27699-4300		Chief Clerk's Office North Carolina Utilities Commission 430 North Salisbury Street Raleigh, NC 27603-5918

34. Enclose a filing fee as required by G.S. 62-300. A Class A utility (annual natural gas reseller revenues of $1,000,000 or more) requires a $250 filing fee. A Class B utility (annual natural gas reseller revenues between $200,000 and $1,000,000) requires a $100 filing fee. A Class C utility (annual natural gas reseller revenues less than $200,000) requires a $25 filing fee. **MAKE CHECK PAYABLE TO N.C. DEPT. OF COMMERCE/UTILITIES COMMISSION.**

35. This application may be filed before title to the property passes to the new purchaser. In that event, the deed required in Item 26 above shall be filed with the Commission as a follow-up to the initial transfer application once the deed has been executed and recorded with the Register of Deeds. The Commission may approve the transfer application on the condition that it is not effective until the deed is executed, recorded, and has been filed with the Commission.

SIGNATURES

36. Application shall be signed by an authorized representative of the seller.

Signature: ______________________

Printed Name: ______________________

Title: ______________________

Date: ______________________

GENERAL ORDERS – NATURAL GAS RESELLER

37. Application shall be signed and verified by an authorized representative of the purchaser.

Signature: ______________________________

Printed Name: ______________________________

Title: ______________________________

Date: ______________________________

38. (Typed or printed name of the purchaser's representative) ______________________________, personally appearing before me and, being first duly sworn, says that the information contained in this application and in the exhibits attached hereto is true to the best of his/her knowledge and belief.

This the ________ day of ________________, 20 _____

____
Signature of Notary Public

____
Name of Notary public – Typed or printed

My Commission Expires: ____________________
Date

(NOTARY SEAL)

DOCKET NO. P-100, SUB 110

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Telecommunications Relay Service (TRS), Relay North Carolina	)))	ORDER DECREASING THE TELECOMMUNICATIONS RELAY SERVICE SURCHARGE

BY THE COMMISSION: On March 8, 2018, the North Carolina Department of Health and Human Services (DHHS) filed a petition requesting that the Commission approve a decrease in the monthly Telecommunications Relay Service (TRS) surcharge pursuant to G.S. 62-157(b) and (c) from $0.10 to $0.08. TRS enables an individual with a hearing or speech disability to communicate by telephone with a person without such a disability. G.S. 62-157(b) and (c) direct the Commission to require local service providers to impose a monthly surcharge (set by the Commission) on qualified access lines to fund the implementation and operation of a relay service and an equipment distribution program, including a "reasonable margin for reserve."[1] G.S. 62-157(i) authorizes wireless providers to impose the same monthly surcharge on each wireless connection. The relay service and equipment distribution service comprise the Telecommunications Resources Program (TRP), which is administered by the Division of Services for the Deaf and Hard of Hearing, a division of DHHS. G.S. 62-157 provides that the funds from the surcharge on access lines are available to DHHS to operate and promote the service.

The Commission set the current surcharge by Order dated September 21, 2015, in which the Commission approved a decrease in the surcharge to the current rate of $0.10 per access line.

DHHS stated in its petition that the reserve margin, as of the date of its filing, is approximately $10.8 million above the $6.5 million set by the Commission, due to actual expenditures being less than had been projected. In addition, DHHS projects that, under the current surcharge, TRP will continue to experience an increase of revenues versus expenditures, thus resulting in the continuing increase in the reserve over the authorized margin. DHHS requested that the surcharge be decreased to $0.08 to allow continued operations and reduce the reserve to the required amount.

On March 15, 2018, the Commission issued an Order Seeking Comments Regarding Surcharge Decrease in which it requested interested parties to file comments regarding the proposed reduction in the TRS surcharge as requested by DHHS. No comments were filed.

The Public Staff presented this matter at the Commission's Regular Staff Conference on April 30, 2018. The Public Staff stated that it had reviewed the petition and, based on an analysis of current and projected expenditures and of projected access line and wireless line growth, it believed that the $0.10 will result in continued growth of the excess over the $6.5 million reserve

[1] The current reserve margin of $6.5 million was approved by the Commission on July 7, 2010.

margin set by the Commission. Based upon its review, the Public Staff recommended approval of the decrease to $0.08, as requested by DHHS.

The Public Staff recommended that the effective date be set for July 1, 2018, to ensure carriers have sufficient time to implement the rate change.

Based on the foregoing, and entire record in this matter, the Commission is of the opinion that the TRS surcharge should be decreased as requested by DHHS effective July 1, 2018, and that notice should be given to customers of this decrease.

IT IS, THEREFORE, ORDERED as follows:

1. That the monthly TRS surcharge shall be decreased from $0.10 per access line to $0.08 per access line effective for bills issued on or after July 1, 2018. The decrease shall be reflected on customers' bills issued on or after July 1, 2018.

2. That the bill message/insert as set forth in Appendix A shall be provided to all customers.

3. That DHHS shall revise the TRS surcharge remittance form to reflect the decrease in the surcharge and shall post the revised form on the Telecommunications Resource Program website so as to make it available for downloading.

ISSUED BY ORDER OF THE COMMISSION.
This the 1st day of May, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

Commissioner James G. Patterson did not participate in this decision.

APPENDIX A

NOTICE OF TELECOMMUNICATIONS RELAY SERVICE (TRS)
SURCHARGE DECREASE

Effective with telephone bills issued on or after July 1, 2018, the Telecommunications Relay Service (TRS) surcharge is $0.08 per access line, per month. On May 1, 2018, the North Carolina Utilities Commission authorized a decrease in the monthly TRS surcharge amount from $0.10 to $0.08 to maintain adequate funding for Division of Services for the Deaf and Hard of Hearing (DSDHH), including the Telecommunications Resource Program (TRP) and the Regional Resource Centers within DSDHH. TRP is a program within the North Carolina Department of Health and Human Services consisting of a telecommunications relay service that enables persons with hearing, speech, and vision impairments to communicate with others by telephone and an equipment distribution program. Regional Resource Centers provide a wide spectrum of services, including: (1) advocacy, consultation, workshops and training on a wide variety of topics pertaining to hearing loss; (2) communication support; (3) information and referral services; (4) assistance with selection, application for and set-up of equipment, training, and technical assistance as part of the equipment distribution service; and (5) outreach regarding available resources.

DOCKET NO. P-100, SUB 170

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Tariff Filings Made by Local Exchange	)	ORDER GRANTING THE PUBLIC
Carriers in Compliance with the Federal	)	STAFF'S MOTION WITH AN
Communications Commission's Connect	)	EFFECTIVE DATE OF JULY 3, 2018
America Fund Order	)	FOR RATE CHANGES

BY THE COMMISSION: On May 24, 2018, the Public Staff filed a Motion for Order Requiring Filing of Information Regarding July 1, 2018, Access Rate Changes.

In its Motion, the Public Staff requested that the Commission issue an order requiring filings from certain carriers showing their compliance with the sixth set of intrastate access rate changes mandated by the Federal Communications Commission's (FCC's) November 18, 2011, Universal Service Fund (USF)/ Intercarrier Compensation (ICC) Transformation Order as soon as practicable, but no later than June 18, 2018.

The Public Staff further noted that it has reviewed last year's responses and compiled a list of carriers as reflected in Appendix A to its Motion that the Public Staff proposes should make an appropriate filing regarding their 2018 switched access rate changes. The Public Staff stated that, additionally, any carrier that is not listed in Appendix A, but whose status has changed from last year should also be required to make an appropriate filing.

On May 25, 2018, the Commission issued an Order Requesting Comments on the Public Staff's Motion.

The Commission notes that on April 5, 2018, the FCC issued an Order establishing procedures for the 2018 filing of annual access charge tariffs. The FCC's Order sets a modified effective date of July 3, 2018, for the July 2018 annual access charge tariff filings made on both 15 and 7 days' notice.

The Public Staff filed a letter on May 31, 2018 requesting that, if the Commission grants the Public Staff's Motion, the Commission's Order reflect an effective date of July 3, 2018, consistent with the FCC's April 5, 2018 Order. No other party filed initial comments on the Public Staff's Motion.

The Commission, therefore, finds it appropriate for the effective date of the intrastate rate changes required due to the USF/ICC Transformation Order to mirror the effective date of the interstate rate changes (i.e., July 3, 2018).

Based on the record, the Commission finds it appropriate to grant the Public Staff's Motion. Therefore, impacted carriers must make the required filings as soon as practicable, but no later than Monday, June 18, 2018 with an effective date of July 3, 2018, as appropriate.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 5th day of June, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. T-100, SUB 49

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petition of the North Carolina Movers Association, Inc., For Amendment of the Maximum Rate Tariff Rule 11 To Allow For Credit Card Transactions and For Flat Screen Television Packing Rates	) ORDER GRANTING PETITION) ALLOWING PROCESSING FEE) FOR CREDIT/DEBIT CARDS TO) BE PASSED ON TO SHIPPER) AND ADOPTING FLAT SCREEN) TELEVISION PACKING RATES

BY THE COMMISSION: On December 14, 2017, the North Carolina Movers Association, Inc., (NCMA) filed a petition with the North Carolina Utilities Commission (Commission) requesting an amendment to the current Commission-approved Maximum Rate Tariff No. 1 (MRT) to include credit card transactions and flat screen television packing rates.

Presently, as written, Section I, Rule 11 of the MRT lists the payment options that a carrier may receive from the shipper for services rendered as: cash, money order, certified check, and traveler's check. Although Rule 11 of the MRT does not prohibit the use of credit and debit cards as a form of payment, it does not address the recovery of the processing fee for credit and debit cards. Additionally, the current MRT does not list any rates to account for the special packing that flat screen televisions require to prevent damages during a move.

In its petition, the NCMA requested that the Commission modify the MRT as follows: (1) Section I, Rule 11 to allow carriers to recoup the costs of processing credit and debit card transactions by having the ability to pass through the processing charge to the shipper; and (2) modify Section IV, Item 1, Item 2, and Item 3, to establish rates and overtime rates for packing and unpacking flat screen televisions and packing container charges for flat screen televisions.

In support of its petition, the NCMA submitted that most shippers now prefer to pay by credit or debit card and that processing charges vary for each carrier. The NCMA requested that carriers be permitted to pass through the processing charge to the shipper. The NCMA proposed that the following language be added to Section I of Rule 11 of the MRT:

> (E) Carriers may accept credit or debit cards. The processing fee for these transactions may be passed on to the shipper. Carriers may only charge the amount their credit card processing company charges the carrier for the individual transaction. The credit card processing fee will be listed on the bill of lading.

Additionally, in its petition, the NCMA stated that flat screen televisions (TVs) have become common place, and while not as heavy as traditional televisions, they need protection by special packing containers. The NCMA, based upon its averaging of the flat screen pricing for packing large and small televisions gathered from two of the largest container companies in North

Carolina, and the addition of a labor charge, proposed the following flat screen television rates to be added to Section IV, Items 1, 2, and 3:

Item 1 –Packing and Unpacking	Flat Screen TVs (small) $115.00
	Flat Screen TVs (large) $125.00
Item 2 –Overtime Packing and Unpacking	Flat Screen TVs (small) $130.00
	Flat Screen TVs (large) $150.00
Item 3 –Packing Container Charges	Flat Screen TVs (small) $ 50.00
	Flat Screen TVs (large) $ 62.00

On January 11, 2018, the NCMA filed a Supplement to its petition that included the pricing information gathered from two container companies as referenced in its December 14, 2017 petition.

On January 11, 2018, the Commission issued an Order Requesting Comments on Petition.

On January 16, 2018, Bruce Gold of Mather Brothers Moving Company, John E. Thomas of J.E. Thomas and Sons Moving, Jamie B. Currie of A+ Moving and Storage, and Chris Barringer of Barringer Moving & Storage, LLC, filed comments in support of the NCMA's petition.

On January 22, 2018, John Diamond of Hilldrup Moving and Storage, d/b/a Hilldrup Companies, Inc., Kathy Cox of Home Moving Systems, Inc., Steven Roper of College Hunks Hauling Junk and Moving, and F. Todd Lamar and Donna Williams of Armstrong Relocation, filed comments in support of the NCMA's petition.

On January 24, 2018, Todd Cummings of Todds Easy Moves, Ronald and Donald Taylor of ABC Moving & Storage, and Dean Barrett of Steele & Vaughn Moving and Storage filed comments in support of the NCMA's petition.

On February 5, 2018, Lucky Anneheim of Make A Move, and Jimmy D. Fortson of Salisbury Moving and Storage filed comments in support of the NCMA's petition.

On February 7, 2018, Dru Sells Burgin and Josephine C. Sells of Sells Service, Inc., filed comments in support of the NCMA's petition.

On February 9, 2018, the Public Staff filed comments.

On February 19, 2018, David Rushing of All American Relocation and Office Solutions filed comments supporting the recommendations of the Public Staff in its February 9, 2018 comments.

On February 23, 2018, the NCMA filed reply comments.

INITIAL COMMENTS

The Commission received 15 initial comments from 14[1] Commission-certified household goods carriers all in support of the NCMA's petition and also received comments from the Public Staff.

Katherine Cox of Horne Moving Systems, Inc. (Horne) commented that Horne supports the recovery of credit and debit card processing fees and the ability to charge for packing/containers of flat screen televisions. Ms. Cox noted that in 2017, Horne paid an average of 2.4% in credit and debit card processing costs resulting in the Company paying in excess of $6,000 in credit and debit card transaction fees that year. Additionally, Ms. Cox argued that flat screen televisions are the norm now and to ensure safe delivery of them, it is imperative that movers put flat screen televisions in proper containers. Ms. Cox maintained that if flat screen televisions are damaged, they cannot be repaired, thus requiring movers to buy new ones. She stated that her company has been using special boxes for flat screen televisions for years to keep claims costs down, and being able to recoup this expense would also be nice.

F. Todd Lamar of Armstrong Relocation supported the proposal of allowing carriers to pass through credit and debit card processing fees to the consumer. Mr. Lamar opined that credit card processing fees have become an expensive plague on the moving industry. Mr. Lamar observed that credit card companies that offer 2% cash and give high rewards can have processing fees over 6%. Mr. Lamar contended that Armstrong Relocation, an agent for United Van Lines, the largest household goods carrier in the industry and with the buying power of a two billion-dollar Company behind it, incurs an average credit card processing fee of 3.4%. Further, Mr. Lamar argued that if you process $3 million of revenue billed at 3.4% in credit card and debit card processing fees, you would incur $102,000 in credit and debit card transaction fees that his Company would have to make up. He opined that this is not an unreasonable request; for example, Wake County, North Carolina charges a 3.5% processing fee when Wake County real estate taxes are paid via credit card.

Todd Cummings of Todds Easy Moves stated that moving companies should have the right to pass credit and debit card processing fees to customers to cover the costs that moving companies incur for the convenience of allowing customers to pay with credit and debit cards. Mr. Cummings commented that now about 90% of his customers pay by credit card. Mr. Cummings discussed that his Company tried to get customers to use a palm pad for a check card, but within a two-year period, only two people used it. Mr. Cummings further suggested that the bank warns customers not to use their pin numbers, therefore everyone runs their cards as credit resulting in transaction fees.

Dean Barrett of Steele and Vaughn Moving and Storage noted that proper packing prices for flat screen TVs have been a long time coming; flat screen TVs require special packaging due to their size and value to the customer. Mr. Barrett stated that flat screen TVs are getting larger and more expensive, therefore, compensating movers for properly packaging flat screen TVs allows movers to provide the quality service that customers deserve. Mr. Barrett maintained that

[1] Donna Williams and Todd Lamar, both of Armstrong Relocation, filed separate, individual comments.

packaging suppliers are working hard to accommodate these needs at an affordable cost, unfortunately there is a cost that comes with proper packing materials for flat screen TVs.

Justin Barringer of **Barringer Moving & Storage** stated that it is common sense for movers to charge packing fees for the labor and materials to protect flat screen TVs just like movers do for any other item that they pack. Mr. Barringer supported the NCMA's petition for flat screen television rates. Mr. Barringer surmised that his Company has to order flat screen TV boxes just like they have to order other packing boxes such as: 1.5's, 3.1's, 4.5's, dish packs, etc., that they are able to charge for, therefore it would be a loss to not charge for flat screen TV boxes and packing labor. He stated that the Company is spending money and time on materials for packing flat screen TVs that it cannot charge to the customer.

Nine other Commission-certified household goods carriers filed basic comments expressing their agreement with the NCMA's petition.

The **Public Staff** stated that in regard to the request for recovery of credit and debit card processing fees, that it agreed with the NCMA's position that the MRT should be updated to expressly provide for the payment by shippers with credit and debit cards, and to allow the carrier to pass through the actual amount of the credit or debit card processing fee to the shipper.

The Public Staff noted that the proposed language submitted by the NCMA for inclusion of credit and debit fees in Section I, Rule 11 (Payments) of the MRT should include the following alteration:

> (E) Carriers may accept credit or debit cards. The processing fee for these transactions may be passed on to the shipper. Carriers may only charge up to the amount their credit card processing company charges the carrier for the individual transaction. The credit card processing fee will be listed on the bill of lading.

The Public Staff maintained that the addition of the words "up to" are in keeping with the MRT, which sets a maximum, but not a minimum, rate and allows the carrier discretion as to how much of the processing fee it will pass through to the shipper.

The Public Staff argued that flat screen televisions have become ubiquitous and require special containers and handling. The Public Staff stated that it does not oppose the addition of specific rates for packing and unpacking, and containers for flat screen televisions. However, the Public Staff argued that the rates proposed by the NCMA should be calculated differently.

The Public Staff maintained that the rates proposed by the NCMA differentiate between small and large flat screen televisions. However, there is no definition of "small" or "large." The Public Staff recommended that the Commission define what constitutes a "small" and "large" flat screen television so that customers and carriers are clear as to what charges are applicable. Additionally, the Public Staff stated that one option the Commission might consider would be to define "small" flat screen televisions as those with screens less than 40 inches (measured diagonally), and "large" flat screen televisions as those with screens of 40 inches or more (measured diagonally).

The Public Staff stated that while the NCMA's use of two workers in calculating its proposed rates appears reasonable, the use of a full hour of labor does not appear to be necessary, especially when carriers bill in 15-minute increments. The Public Staff noted that it surveyed several well-known carriers to determine the average labor time associated with the packing of a flat screen television, which includes disconnection and reconnection of cables and associated hardware. Based on this survey, the Public Staff maintained that it would be more reasonable to use a maximum of 30 minutes of labor time for packing and unpacking in calculating the appropriate rate. The Public Staff further argued that the use of 30 minutes is also consistent with its research regarding industry guidelines for packing flat screen televisions.

The Public Staff noted Section IV, Items 1, 2, and 3 of the MRT should be modified to establish rates for packing and unpacking flat screen televisions and charges for packing containers for flat screen televisions. The Public Staff proposed the use of a maximum of 30 minutes of labor for packing and unpacking for the following rates for flat screen televisions:

Item 1 –Packing and Unpacking	Flat Screen TVs (small) $82.40
	Flat Screen TVs (large) $94.40
Item 2 –Overtime Packing and Unpacking	Flat Screen TVs (small) $89.70
	Flat Screen TVs (large) $101.70
Item 3 –Packing Container Charges	Flat Screen TVs (small) $ 50.00
	Flat Screen TVs (large) $ 62.00

Further, the Public Staff noted that these rates would be subject to the automatic annual increase allowed for all MRT rates.

REPLY COMMENTS

David Rushing of <u>All American Relocation and Office Solutions</u> filed comments expressing its agreement with the recommendations of the Public Staff.

The <u>NCMA</u> stated that the Public Staff supported the language proposed by the NCMA for inclusion in Section I, Rule 11 of the MRT with the addition of the words "up to" included in the proposed language. The NCMA agreed with the Public Staff's suggestion in this regard.

The NCMA also noted that it concurred with the Public Staff's recommended definitions for "small" and "large" flat screen televisions wherein a small TV would be defined as less than 40 inches (measured diagonally) and a large TV would be 40 inches or more (measured diagonally).

Further, the NCMA maintained that it does not have any issues with the Public Staff's recommendation to reduce the amount of labor to two men for 30 minutes for packing and unpacking flat screen TVs for both Item 1 and Item 2, and therefore, supports the Public Staff's proposals in this regard.

WHEREUPON, the Commission now reaches the following

CONCLUSIONS

Based upon the record of evidence in this proceeding, including the NCMA's petition, and the initial and reply comments filed thereafter, the Commission finds it appropriate to grant the NCMA's petition to amend the MRT to allow movers the ability to pass on the costs of processing debit and credit card transactions to the shipper, and establish rates for packing and unpacking flat screen televisions and charges for flat screen television container charges, but adopting the Public Staff's recommended changes.

The Commission recognizes that all of the parties that filed comments agreed that modifying the MRT for these purposes is appropriate and warranted. The Commission understands that more and more people are using credit and debit cards as their preferred form of payment. The Commission acknowledges that moving companies are incurring significant credit and debit card processing fees, which they have to absorb as a business expense. The Commission is of the opinion that Commission-certified household goods movers should be granted the ability to pass on credit and debit card processing fees to their clients to offset this additional business expense.

The Commission concurs with the Public Staff's recommendation to allow movers to pass on the credit and debit card processing fees on to the shipper, with the caveat that the mover may bill the shipper "up to" the amount of the processing fee that its credit or debit card company bills per individual transaction. Accordingly, the Commission is of the opinion that the MRT should be amended to reflect the Commission's authorization for the allowance of passing credit and debit card processing fees on to the consumer. Therefore, the Commission finds it appropriate to adopt a new section (E) for Section I, Rule 11 of the MRT as proposed by the Public Staff including the requirement that the credit card processing fee will be listed on the bill of lading.

The NCMA, in its December 14, 2017 petition, recommended that the Commission modify the MRT to establish rates for packing and unpacking flat screen televisions and charges for packing containers. The NCMA proposed to calculate packing container charges for flat screen televisions based on the average cost of container boxes quoted by the two largest container companies in North Carolina and a labor charge of two workers for one hour.

The Public Staff argued that the NCMA's use of two workers in calculating its proposed rate appeared reasonable, however the use of a full hour of labor does not appear necessary, especially when carriers can bill in 15-minute increments. The Public Staff also noted that the NCMA did not define what size constituted a large or small television. The Public Staff stated that a flat screen television with a screen size of less than 40 inches (measured diagonally) should be defined as small and a flat screen television with a screen size 40 inches or greater (measured diagonally) should be defined as a large television.

In its reply comments, the NCMA agreed with the Public Staff's recommended rates for packing and unpacking flat screen televisions.

Based upon the foregoing, the Commission finds that it is appropriate to adopt the Public Staff's proposed modifications to Section IV, Items 1, 2, and 3 of the MRT to establish rates for packing and unpacking flat screen televisions and container charges. Further, the Commission notes that the MRT provides the maximum rates that movers may charge, however shippers may negotiate rates for their move that are below the MRT rates.

IT IS, THEREFORE, ORDERED as follows:

1. That the NCMA's petition for the modification of the MRT to allow movers to pass through credit card and debit card processing fees to the shipper, and establish flat screen television packing and unpacking rates and container charges is hereby granted with the clarifications as set forth in this Order.

2. That a new Section (E) shall be added to Section I, Rule 11 of the MRT as specified by the Public Staff to allow Commission-certified household goods movers to accept credit and debit cards and to charge the shipper up to the amount the credit card processing company charges the carrier for the individual transaction.

3. That Section IV, Items 1, 2, and 3 of the MRT shall be amended as specified by the Public Staff to include rates for packing and unpacking flat screen televisions, and container charges.

4. That the current Commission-approved paper bill of lading shall be modified to include a section for credit and debit card processing fees. Any Commission-certified household goods mover as of the date of this Order is allowed to use its current supply of the Commission-approved paper bill of ladings through December 31, 2018. However, after December 31, 2018, all Commission-certified household goods movers shall no longer use the current Commission-approved bill of lading and instead shall use the newest revision (June 2018) of the Commission-approved bill of lading.

5. That any Commission-certified household goods mover as of the date of this Order that opts to use electronic bill of lading as an alternative to the revised (June 2018) Commission-approved paper bill of lading shall modify its electronic bill of lading to include a line item for credit and debit card processing fees, if the mover chooses to bill shippers for credit and debit card processing fees.

6. That copies of this Order shall be served by the Chief Clerk's Office to all Commission-certified household goods movers, the Public Staff, the Office of the North Carolina State Highway Patrol, the Office of the Attorney General, all applicants with pending applications seeking certificates of exemption, and the North Carolina Movers Association, Inc.

ISSUED BY ORDER OF THE COMMISSION.
This the 14th day of May, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

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

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1131 In the Matter of Application by Duke Energy Progress, LLC, for Accounting Order to Defer Incremental Storm Damage Expenses DOCKET NO. E-2, SUB 1142 In the Matter of Application by Duke Energy Progress, LLC, For Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina DOCKET NO. E-2, SUB 1103 In the Matter of Joint Application by Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, for Accounting Order to Defer Environmental Compliance Costs DOCKET NO. E-2, SUB 1153 In the Matter of Petition of Duke Energy Progress, LLC, for an Order Approving a Job Retention Rider	ORDER ACCEPTING STIPULATION, DECIDING CONTESTED ISSUES AND GRANTING PARTIAL RATE INCREASE

HEARD: Tuesday, September 12, 2017, at 7:00 p.m., Richmond County Courthouse, Courtroom A, 105 W. Franklin Street, Rockingham, North Carolina

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

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

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

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

Monday, November 27, 2017, at 1:30 p.m., Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding; Commissioners Bryan E. Beatty,[1] ToNola D. Brown-Bland, Jerry C. Dockham, James G. Patterson, Lyons Gray, and Daniel G. Clodfelter

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

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

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BY THE COMMISSION: On May 2, 2017, pursuant to Commission Rule R1-17(a), Duke Energy Progress, LLC (DEP or the Company) filed notice of its intent to file a general rate case application. On June 1, 2017, the Company filed its Application to Adjust Retail Rates and Request for Accounting Order (Application), along with a Rate Case Information Report Commission Form E-1 (Form E-1), and the direct testimony and exhibits of David B. Fountain, President, DEP; Laura A. Bateman, Director of Rates and Regulatory Planning, DEP; T. Preston Gillespie, Jr., Senior Vice President and Nuclear Chief Operating Officer, Duke Energy Corporation (Duke Energy);[1] Stephen G. De May, Senior Vice President of Tax and Treasurer, Duke Energy Business Services, LLC (DEBS);[2] David L. Doss, Jr., Director of Electric Utilities and Infrastructure Accounting, DEBS; Christopher M. Fallon, Vice President of Duke Energy Renewables and Commercial Portfolio, Duke Energy; Janice Hager, President, Janice Hager Consulting; Robert B. Hevert, Partner, ScottMadden, Inc.; Retha Hunsicker, Vice President of Customer Information Systems - Customer Operations, DEBS; Jon F. Kerin, Vice President of Governance and Operations Support – Coal Combustion Products, DEBS; Julius A. Wright, Managing Partner, J.A. Wright & Associates, LLC; Kimberly D. McGee, Rates and Regulatory Strategy Manager, DEP and Duke Energy Carolinas, LLC (DEC); Joseph A. Miller, Jr., Vice President of Central Services, DEBS; Robert M. Simpson, III, Director of Grid Improvement Plan Integration for Duke Energy's Regulated Utilities Operations, DEP; and Steven B. Wheeler, Director, Pricing and Regulatory Solutions Director, DEBS.

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

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

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

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

On August 10, 2017, and October 5, 2017, the Commission entered Orders denying the petitions to intervene of Piedmont EMC and the Quad Towns, respectively, but allowing each to participate as an amicus curiae on the issue of DEP's coal combustion residual (CCR) costs.[1] By Order dated December 20, 2017, the Commission denied John Everett's Motion to Intervene as being untimely.

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

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

On July 10, 2017, the Commission issued an Order consolidating Docket No. E-2, Sub 1142 with Docket No. E-2, Sub 1131 (DEP's request to defer incremental storm damage expenses) and Docket Nos. E-2, Sub 1103 and E-7, Sub 1110 (DEP and DEC's requests to defer environmental compliance costs regarding CCRs), allowing those persons who had been granted intervention in those dockets to fully participate in this proceeding. In addition, on August 29, 2017, the Commission issued an Order consolidating DEP's request to implement a job retention rider filed in Docket No. E-2, Sub 1153 with this general rate proceeding.

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

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

On September 22, 2017, Kroger filed the direct testimony and exhibits of Justin Beiber, Senior Consultant, Energy Strategies, LLC. On October 18, 2017, EDF filed the direct testimony of Paul J. Alvarez, President, Wired Group. On October 19, 2017, DoD/FEA filed the direct testimony and exhibits of Constance T. Cannady, Executive Consultant, NewGen Strategies and Solutions, LLC, and Joseph A. Mancinelli, General Manager, NewGen Strategies and Solutions, LLC. On October 20, 2017, the Public Staff filed the direct testimony and exhibits of Jack L. Floyd, Utilities Engineer, Public Staff Electric Division, Jay B. Lucas, Utilities Engineer, Public Staff

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

Electric Division, JamesS. McLawhorn, Director, Public Staff Electric Division, Dustin R. Metz, Utilities Engineer, Public Staff Electric Division, Tommy C. Williamson, Jr., Utilities Engineer, Public Staff Electric Division, Scott J. Saillor, Utilities Engineer, Public Staff Electric Division, Michael Maness, Director, Public Staff Accounting Division, Darlene P. Peedin, Manager, Electric Section, Public Staff Accounting Division, David C. Parcell, Principal and Senior Economist, Technical Associates, Inc., Roxie McCullar, Consultant, William Dunkel and Associates, Vance F. Moore, President, Garrett and Moore, Inc., and L. Bernard Garrett, Secretary/Treasurer, Garrett and Moore, Inc.; CUCA filed the direct testimony and exhibits of Kevin W. O'Donnell, President, Nova Energy Consultants, Inc.; Fayetteville PWC filed the direct testimony and exhibits of Nancy Heller Hughes, Director, NewGen Strategies and Solutions, LLC; CIGFUR filed the direct testimony and exhibits of Nicholas Phillips, Jr., public utility regulation consultant and a Managing Principal of Brubaker & Associates, Inc.; NC Justice Center filed the direct testimony and exhibits of Jonathan Wallach, Vice President, Resource Insight, Inc., and Satana Deberry, Executive Director, NC Housing Coalition; NCSEA filed the direct testimony and exhibits of Michael Murray, President, Mission:data Coalition, Justin R. Barnes, Director of Research, EQ Research, LLC, and Carolina Golin, Southeast Regulatory Director, Vote Solar; Sierra Club filed the direct testimony and exhibits of Ezra D. Hausman, consultant, Ezra Hausman Consulting, and Mark Quarles, principle scientist and owner, Global Environmental, LLC; NCLM filed the direct testimony of Bill Saffo, Mayor of Wilmington, North Carolina; the Attorney General filed the direct testimony and exhibits of Richard A. Polich and Dan J. Wittliff, Managing Directors, GDS Associates, Inc.; and Commercial Group filed the direct testimony and exhibits of Steve W. Chriss, Director, Energy and Strategy Analysis, Wal-Mart Stores, Inc., and Wayne Rosa, Energy and Maintenance Manager, Food Lion, LLC. On October 20, 2017, the Commission issued an Order granting the motion of NC Justice Center to extend to October 23, 2017, the deadline to file the direct testimony of witness, John Howat. On October 23, 2017, NC Justice Center filed the direct testimony and exhibits of John Howat, Senior Policy Analyst, National Consumer Law Center.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

FINDINGS OF FACT

Jurisdiction

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

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

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

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

The Application

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

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

The Stipulation

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

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

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

ELECTRIC – ACCOUNTING

Adjustments to Cost of Service

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

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

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

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

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

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

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

16. The Stipulating Parties agree that the revenue increase approved in this Order is intended to provide DEP, through sound management, the opportunity to earn an overall rate of return of 7.09%. This overall rate of return is derived from applying an embedded cost of debt of 4.05% and a rate of return on equity of 9.9% to a capital structure consisting of 48% long-term debt and 52% members' equity. The Stipulation is material evidence entitled to appropriate

weight in determining DEP's overall rate of return, cost of debt, rate of return on equity, and capital structure.

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

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

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

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

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

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

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

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

Base Fuel Factor and Coal Inventory

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

26. As set forth in Paragraph III.R. of the Stipulation, DEP shall reduce the amount of coal inventory included in working capital. An increment rider shall be established, effective on the same date as the new base rates approved in this Order and continuing until inventory levels reach a 35-day supply, to allow the Company to recover the additional costs of carrying coal inventory in excess of a 35-day supply (priced at $76.11 per ton). This rider shall terminate the earlier of: (a) January 30, 2020, or (b) the last day of the month in which the Company's actual coal inventory levels return to a 35-day supply on a sustained basis, as defined in the Stipulation. The reduction to coal inventory included in working capital and the establishment of the increment rider, as set forth in the Stipulation, is just and reasonable to all parties in light of all the evidence presented.

Quality of Service, Vegetation Management, and Service Regulations

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

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

Power/Forward Workshop

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

Lead-Lag Study

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

Cost of Service Allocation Methodology

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

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

Rate Design

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

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

Acceptance of Stipulation

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

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

Storm Costs

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

38. In this proceeding, DEP included a pro forma adjustment to the test year to normalize for storm costs to an average level of costs the Company has experienced over the last ten years. This pro forma adjustment also removed any storm costs from the 10-year average calculation that were included in the Company's 2016 deferral request, and instead included an amortization of the deferred costs over a 3-year period.

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

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

41. It is appropriate for the Company to defer and amortize $51.032 million ($80.152 million total requested O&M expense minus $1.720 million for the June and July

thunderstorms minus $27.4 million normal storm expense) of its North Carolina retail storm costs incurred in the test year. The $51.032 million deferral should be amortized over a period of five years, beginning in October 2016.

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

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

Job Retention Rider

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

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

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

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

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

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

Coal Combustion Residual Cost Deferral

50. In Docket Nos. E-2, Sub 1103 and E-7, Sub 1110, DEP and DEC jointly filed a request that the Commission issue an order authorizing them to defer in a regulatory asset account certain costs incurred in connection with compliance with federal and state environmental requirements regarding coal combustion residuals (CCRs). By Order dated July 10, 2017, the Commission consolidated the DEP request with the present general rate case. DEP and the Public Staff supported the deferral in their testimony in this docket. The deferral request is reasonable and appropriate.

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

52. It is reasonable and appropriate to use a mid-month cash flow convention for calculation of the return on the principal amount of deferred CCR expenditures through January 2018.

Recovery of CCR Costs

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

54. On a North Carolina retail jurisdiction basis, the actual coal ash basin closure costs DEP has incurred (netted against the amount already included in the Company's rates following its last rate case) during the period from January 1, 2015, through August 31, 2017, amount to $241,890,000. DEP is entitled to recover these coal ash basin closure costs, less a disallowance of $9.5 million, for a total amount of $232,390,000.[1] The actual coal ash basin closure costs incurred by DEP, less the $9.5 million, are known and measurable, reasonable and prudent, and used and useful in the provision of service to the Company's customers. DEP is entitled to recover these costs through rates. Further, DEP proposes that these costs be amortized over a five-year period and that it earn a return on the unamortized balance. Under normal circumstances, the five-year amortization period proposed by the Company is appropriate and reasonable, and absent any management penalty should be approved, and under normal circumstances the Company is entitled to earn a return on the unamortized balance.

55. Under the present facts, a mismanagement penalty in the approximate sum of $30 million is appropriate with respect to DEP's CCR remediation expenses accounted for in the earlier established asset retirement obligation (ARO) with respect to costs incurred through the end of the test year, as adjusted. Through its use of available ratemaking mechanisms, the Commission is effectively implementing an estimated $30 million penalty by amortizing the $232,390,000 over five years with a return on the unamortized balance and then reducing the resulting annual revenue requirement by $6 million for each of the five years.

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

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

ELECTRIC – ACCOUNTING

Requested CCR Fuel Costs

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

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

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

Provisional CCR Cost Recovery

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

CCR Allocation Guidelines

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

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

Insurance Litigation

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

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

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

ELECTRIC – ACCOUNTING

Advanced Metering Infrastructure

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

Accounting for Deferred Costs

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

Federal Income Tax Changes

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

Revenue Requirement

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

70. DEP should recalculate and file the annual revenue requirement with the Commission within 10 days of the issuance of this Order, consistent with the findings and conclusions of this Order. The Company should work with the Public Staff to verify the accuracy of the filing. DEP should file schedules summarizing the gross revenue and the rate of return that the Company should have the opportunity to achieve based on the Commission's findings and determinations in this proceeding.

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

Just and Reasonable Rates

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

ELECTRIC – ACCOUNTING

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

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

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

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

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

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

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

Discharge flue desulfurization systems for existing coal plants, including a $141 million system at the Mayo Unit 1 facility that provides operational flexibility and reduces environmental impact. (Id.)

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

Witness Fountain explained that under DEP's proposed rate adjustment customers would still be paying lower rates today than they were in 1991 on an inflation-adjusted basis, and customers will continue to pay rates below the national average and competitive with other utilities in the region. (Id. at 46.) He pointed out that customers' bills have also declined from those approved in 2013 due, in part, to the Company prudently managing fuel costs and jointly dispatching the generation fleet to save $183 million. (Id. at 45.)

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

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

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7-9

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

ELECTRIC – ACCOUNTING

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

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

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

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

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

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

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

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

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

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

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

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

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

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

12. Coal Inventory – The Stipulating Parties agree that for purposes of settlement, the Company may set carrying costs included in base rates assuming a 35-day coal inventory at 100% capacity factor (full load burn), and that a Coal Inventory rider should be allowed to manage the transition, and that the rider will terminate upon the sooner of the Company reaching a 35-day coal inventory on a sustained basis or two years from approval by the Commission. The Company will conduct an analysis in consultation with the Public Staff demonstrating the appropriate coal inventory level given market and generation changes since the Company's last rate case. The analysis shall be completed by December 31, 2018.

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

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

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

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

17. Other Cost of Service and Rate Design Matters -- The Stipulating Parties have also agreed upon rate design and cost of service study parameters as proposed by Company witnesses Wheeler and Hager and Public Staff witness Floyd.

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

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

Id. at 88-92.

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

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

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

Stipulation reflects the result of good faith "give-and-take" and compromise-related negotiations among the parties.

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

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

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

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

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

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

ELECTRIC – ACCOUNTING

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

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

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

Update plant and accumulated depreciation to October 31, 2017

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

Update revenues to October 31, 2017

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

Update labor costs through September 30, 2017

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

ELECTRIC – ACCOUNTING

Adjust for lost industrial revenues due to Hurricane Matthew

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

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

Adjust aviation expenses

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

Adjust executive and incentive compensation

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

Public Staff witness Peedin recommended removal of 50% of the compensation for a fifth executive, as well as 50% of the benefits associated with the top five executives. (Tr. Vol.18, pp. 67-70.) Witness Peedin recommended disallowance of incentive compensation related to earnings per share (EPS) and total shareholder return (TSR). (Id.) Witness Peedin asserts that incentive compensation tied to EPS and TRS metrics should be excluded because it provides a direct benefit to shareholders only, rather than to customers. (Id. at 70.) Witness Peedin also asserts that executive compensation and benefits should be excluded because these executives' duties are closely linked to shareholder interests. (Id.) DoD/FEA witness Cannady also recommended removal of non-qualified pension expense. (Tr. Vol. 17, p. 183.) Witness Cannady, while acknowledging that the Commission has historically allowed non-qualified pension expense, advocates its exclusion in this case because of her belief that customers should not be responsible for benefits available only to management and executive employees at the higher end of the pay scale. (Id. at 183-84.)

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

The Stipulation provides that "[t]he Company accepts the Public Staff's proposed adjustment to executive compensation to remove 50% of the compensation for the five Duke Energy executives with the highest amounts of compensation, and to remove 50% of the benefits associated with those five executives." (Stipulation Paragraph III.F.)

As part of settlement, the parties agreed to accept the Public Staff's adjustment with a modification to limit the incentives removed. This agreement is reflected in Section III.Q. of the Stipulation, which provides that the Company's employee incentives should be adjusted to remove the cost of the STIP Plan based on the Company's EPS for employees who qualify for the Company's LTIP.

Adjust Sutton CT Blackstart plant cost

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

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

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

Adjust Mayo Zero Liquid Discharge plant cost

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

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

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

Vegetation Management

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

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

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

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

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

Outside Services

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

Removal of costs to achieve Duke Energy-Piedmont merger

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

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

In her rebuttal testimony, witness Bateman explained that the Company opposed this adjustment. (Tr. Vol. 6, p. 162.) She noted that the costs that witness Peedin has removed are operating expenses, not capital costs. (Id. at 162-63.) According to witness Bateman, the Merger Order does not specifically address cost recovery for operating expenses associated with achieving merger savings. (Id. at 163.) Witness Bateman explained that operating expenses are different from capital costs, and the Company cannot simply capitalize and depreciate operating expenses like witness Peedin suggests. (Id.)

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

ELECTRIC – ACCOUNTING

Adjust Allocations by DEBS to DEP

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

Lobbying and Board of Director expenses

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

With respect to lobbying expenses, witness Peedin noted that the Company made an adjustment to remove some lobbying expenses from the test year. (Id. at 75.) She further adjusted O&M expenses to remove what she characterized as additional lobbying costs, including O&M expenses that she believed were associated with stakeholder engagement, state government affairs, and federal affairs that were recorded above the line. (Id.) In her rebuttal testimony, witness Bateman explained why the Company opposed this adjustment and disagreed with witness Peedin's characterization of these expenses. (Tr. Vol. 6, p. 166.) Witness Bateman testified that in 2016, the Company engaged a third-party consulting company to perform a detailed time study for the purpose of determining the percentage of time certain individuals spent on lobbying activities per the federal definition in Title 29, Section 367.4264 of the Code of Federal Regulations. (Id.) A report with the results of the study was delivered to the Company in August 2016, and the Company booked journal entries to ensure that the 2016 labor costs were aligned with the results of the independent study. (Id. at 167.) The results are that in the test period, the company booked below the line 66% of the expenses for federal affairs, 75% of the expenses state government affairs, and 10% of the expenses for stakeholder engagement. Witness Bateman concluded that no further adjustments were necessary or justified. (Id.)

Nevertheless, in the spirit of settlement and in the context of the Stipulation as a whole, the Company and the Public Staff have resolved these issues, and in Section III.W. of the Stipulation, the Company agreed to accept the Public Staff's recommended adjustments to lobbying and Board of Directors' expenses. Both parties presented evidence to support their respective positions in direct and rebuttal testimony; however, no party provided clarity regarding the settled position. As previously discussed, the Stipulation is recognized as a series of give-and-take positions by the party.

Sponsorship Expenses

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

Harris COLA

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

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

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

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

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

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

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

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

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

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

> Ascertain the reasonable original cost of the public utility's property used and useful, or to be used and useful within a reasonable time after the test period, in providing the service rendered to the public within the State, less that portion of the cost that has been consumed by previous use recovered by depreciation expense. In addition, construction work in progress may be included in the cost of the public utility's property under any of the following circumstances:
>
> a. To the extent the Commission considers inclusion in the public interest and necessary to the financial stability of the utility in question, reasonable and prudent expenditures for construction work in progress may be included, subject to the provisions of subdivision (4a) of this subsection.

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

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

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

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

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

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

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

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

Customer Connect Program

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Customer Usage Data

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

In her rebuttal testimony, DEP witness Hunsicker responded to witness Howat's recommendation that DEP be required to collect, report by zip code, and make publicly available data regarding residential customer billings, receipts, arrearages, notices of disconnection, uncollectibles, and similar information that is specific to low-income residential customers. Witness Hunsicker testified that DEP disagrees with this recommendation for three reasons: (1) DEP presently complies with all of the Commission's requirements for customer data collection and retention, (2) DEP would be required to collect more customer information than it presently collects and stores, and (3) witness Howat's recommendation would create privacy concerns regarding sharing of customer data. She further noted that DEP does not currently obtain data, such as income level, that would enable it to distinguish between low-income and middle- or upper-income customers.

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

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

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

Deprecation Rates

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

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

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

Contingency

The Company's Decommissioning Cost Estimate Study prepared by Burns and McDonnell included a 20% contingency to cover unknowns. Witness Kopp explained that a contingency cost is included in the Company's Decommissioning Study to account for unspecified, but reasonably expected additional costs to be incurred by the Company during the execution of decommissioning and demolition activities. (Tr. Vol. 12, p. 169.) Indeed, witness Kopp explained that costs incurred by the Company for the decommissioning and demolition of Cape Fear, H.F. Lee, Sutton, Robinson, and Weatherspoon plants were actually 11% higher than forecasted by the Burns and

McDowell Decommissioning Study completed in 2012 for DEP. (Id. at 11.) Public Staff witness McCullar recommended a 0% contingency, expressing concerns that the contingency factor is an uncertain cost in the future that DEP has not specifically identified. (Tr. Vol. 7, pp. 266-67.) Witness Kopp expressed concern over witness McCullar's position because it "misrepresents the purpose of inclusion of contingency in the estimates . . . . [C]ontingency represents costs that are reasonably expected to be incurred, [and] these costs were actually incurred by the Company on projects that have been commissioned to date." (Tr. Vol. 12, p. 176.)

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

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

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

70-R2 for Account 356

DEP proposed a 65-year R2.5 curve for Account 356, Overhead Conductors and Devices. (Tr. Vol. 7, p. 285.) Company witness Spanos explained that most estimates in the industry for Account 356 have service lives of 65 years or less, as opposed to Fayetteville PWC and Public Staff estimates of 70 years or longer. (Tr. Vol. 12, pp. 146- 47.) Public Staff witness McCullar recommended an R2-70 curve for Account 356. (Tr. Vol. 7, pp. 281-82.) Witness McCullar based this view on more recent life experience bands of 1977-2016. (Id. at 285.) Public Staff witness McCullar stated that DEP proposed an increase in life from 60 years to 70 years in its June 28, 2013 Depreciation Study. (Tr. Vol. 7, p. 286.) Witness McCullar also stated that "[t]he Public Staff proposed 70-year R2 curve shape is a better fit to the actual observed life data" upon which DEP based its proposal for this account. (Tr. Vol. 7, pp. 286-87.) The Public Staff and the Company have agreed as Stipulating Parties to a 70-R2 curve for Account 356.

The only other witness making a recommendation on Account 356 was Fayetteville PWC witness Hughes. Witness Hughes recommended an R2-72 survivor curve for Account 356.

(Tr. Vol. 7, p. 201.) Witness Hughes asserted that the R2-72 survivor curve provides a better fit to the actuarial data than DEP's R2.5-65 curve. (Id.) According to witness Hughes, "[t]he SSD for the R2-72 curve is equal to 0.68, which is much lower (better) than the 2.76 SSD for DEP's proposed R2.5-65 survivor curve." (Tr. Vol. 7, p. 201.)

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

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

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

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

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

(Id.)

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

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

Negative 10% net salvage for Account 366

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

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

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

> The estimated future net salvage is part of the annual depreciation accrual, which is credited to the reserve to cover the estimated future net salvage costs the Company may incur associated with plant asset's retirement.

(Id.)

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

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

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

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

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

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

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

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

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

<u>20-year amortization period for Accounts 391 and 397</u>

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

DEP determined the amortization periods to be used as follows:

> The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during

> which the assets will render most of their service, the amortization periods and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

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

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

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

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

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

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

Other Depreciation Recommendations

1. Generation Retirement Dates

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

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

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

2. Account 343, Prime Movers

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

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

In addition, witness Hughes testified that she does not recommend any changes to the proposed net salvage rate for Account 343.1, Prime Movers – Rotable Parts. (Tr. Vol. 7, p. 211.) However, she proposed interim net salvage of zero percent for non-rotable parts as compared to the Company's negative 5% "until there is sufficient data to track the net salvage for the subaccounts separately." (Tr. Vol. 7, p. 209.) In witness Hughes' opinion, there is insufficient data to track the net salvage for the subaccounts separately. (Tr. Vol. 7, pp. 211-12.) Although witness Spanos acknowledged that no historical data exists that can be used to estimate the net salvage specific to non-rotable parts (Tr. Vol. 7, p. 212; Tr. Vol. 12, p. 135), his testimony made clear that assigning a value of 0% to this subaccount is also inappropriate.

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

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

3. Requirement of Workpapers

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

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

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

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

4. CIGFUR Recommendation

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

As witness Spanos correctly asserted, witness Phillips provided no support or justification for his net zero proposal other than a desire that depreciation rates not increase. (Tr. Vol. 12, p. 155.) He offered no credible critique of the Company's filed Depreciation Study and provided no alternative analysis. The current Depreciation Study as modified by the Stipulating Parties demonstrates that current depreciation rates are insufficient and that adjustments are necessary to ensure recovery of the full cost of the Company's assets providing service to DEP customers. (Tr. Vol. 12, p. 155.)

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

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

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

End of Life Nuclear Materials and Supplies Reserve

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

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

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

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

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

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

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

Asheville Plant

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

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

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

EDIT Refund

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

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

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

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

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

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

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

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

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

- Order Granting General Rate Increase in the Company's previous Rate Case, Docket No. E-2, Sub 1023 (May 30, 2013) (2013 DEP Rate Order), which was affirmed by the Supreme Court in State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 444, 761 S.E.2d 640 (2014) (Cooper III);[1]

- Order on Remand resulting from the Supreme Court's Cooper I decision, in Docket No. E-7, Sub 989 (October 23, 2013) (DEC Remand Order), which was affirmed by the Supreme Court in State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 644, 766 S.E.2d 827 (2014) (Cooper IV);
- Order Granting General Rate Increase in DEC's 2013 Rate Case, Docket No. E-7, Sub 1026 (September 24, 2013) (2013 DEC Rate Order), which was affirmed by the Supreme Court in State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 741, 767 S.E.2d 305 (2015) (Cooper V); and
- Order on Remand resulting from the Supreme Court's Cooper II decision, in Docket No. E-22, Sub 479 (July 23, 2015) (DNCP Remand Order), which was not appealed to the Supreme Court.

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

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

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

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

2013 DEP Rate Order, at 29.

Second, the rate of return on equity is, in fact, a cost. The return that equity investors require represents the cost to the utility of equity capital. In his dissenting opinion in Missouri ex rel.

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

ELECTRIC – ACCOUNTING

Southwestern Bell Tel. Co. v. Missouri Pub. Serv. Comm'n, 262 U.S. 276 (1923), Justice Brandeis remarked upon the lack of any functional distinction between the rate of return on equity (which he referred to as a "capital charge") and other items ordinarily viewed as business costs, including operating expenses, depreciation, and taxes:

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

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

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

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

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

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

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

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

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

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

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

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

> Indeed, of all the components of a utility's cost of service that must be determined in the ratemaking process, the appropriate ROE [rate of return on equity] the one requiring the greatest degree of subjective judgment by the Commission. Setting an ROE [rate of return on equity] for regulatory purposes is not simply a mathematical exercise, despite the quantitative models used by the expert witnesses. As explained in one prominent treatise,
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> > 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.
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> > The relevant economic criteria enunciated by the Court are three: financial integrity, capital attraction and comparable earnings. Stated another way, the rate of return allowed a public utility should be high enough: (1) to maintain the financial integrity of the enterprise, (2) to enable the utility to attract the new capital it needs to serve the public, and (3) to provide a return on common equity that is commensurate with returns on investments in other enterprises of corresponding risk. These three economic criteria are interrelated and have been used widely for many years by regulatory commissions throughout the country in determining the rate of return allowed public utilities.
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> > In reality, the concept of a fair rate of return represents a "zone of reasonableness." As explained by the Pennsylvania commission:
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> > > There is a range of reasonableness within which earnings may properly fluctuate and still be deemed just and reasonable and not excessive or extortionate. It is bounded at one level by investor interest against confiscation and the need for averting any threat to the security for the capital embarked upon the enterprise. At the other level it is bounded by consumer interest against excessive and unreasonable charges for service.

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

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

2013 DEP Rate Order, pp. 35-36.

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

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

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

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

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

1. Evidence from expert witnesses on cost of equity capital

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

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

- The Zack's consensus long-term earnings growth estimates;

- The First Call consensus long-term earnings growth estimates; and

- The Value Line earnings growth estimates.

Witness Hevert testified that for each proxy company he calculated the mean, mean high, and mean low results. For the mean result, he combined the average of the EPS growth rate estimates reported by Value Line, Zacks, and First Call with the subject company's dividend yield for each proxy company and then calculated the average result for those estimates. His constant growth DCF results ranged from 8.07% to 9.82%.[1]

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

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

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[1] Table 13 in the rebuttal testimony of witness Hevert contains updated analytical results for his DCF, CAPM, and Bond Yield Risk Premium analyses. However, in summarizing his rebuttal testimony, witness Hevert testified that "[n]one of their [opposing witnesses] arguments caused me to revise my conclusions or recommendations."

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

Witness Hevert testified that for his CAPM analysis risk free rate, he used the current 30-day average yield on 30-year Treasury bonds of 3.06% and the near-term projected 30-year Treasury yield of 3.52%. For the market risk premium, he calculated the market capitalization weighted average total return based on the constant growth DCF model for each of the S&P 500 companies using data from Bloomberg and Value Line. He then subtracted the current 30-year Treasury yield from that amount to arrive at the market DCF-derived forward looking market risk premium estimate. Witness Hevert used the beta coefficients reported by Bloomberg and Value Line. He testified that his CAPM analysis suggested a rate of return on equity range of 9.15% to 11.49%.

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

Witness Hevert testified that he first defined the risk premium as the difference between the authorized rate of return on equity and the then-prevailing level of long-term 30-year Treasury yield. He then gathered data for 1,508 electric utility rate proceedings between January 1980 and March 31, 2017. In addition to the authorized rate of return on equity, he also calculated the average period between the filing of the case and the date of the final order (the "lag period"). In order to reflect the prevailing level of interest rates during the pendency of the proceedings, he calculated the average 30-year Treasury yield over the average lag period of approximately 200 days. He testified that to analyze the relationship between interest rates and the equity risk premium, he used regression analyses. Witness Hevert testified that based upon the regression coefficients, the implied rate of return on equity in his risk premium analysis is between 10.00% and 10.32%.

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

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

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

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

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

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

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

- Five-year projections of EPS growth (per First Call).

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

Witness Parcell performed his DCF analysis on his proxy group of 11 companies, where using only the high mean growth rate the cost of capital was 8.4%, and the Hevert proxy group of 18 companies, where using only the highest mean growth rate the cost of capital was 9.3%. He recommended a DCF rate of return on equity of 8.85% for DEP as the mid-point of the two highest mean growth rates.

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

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

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

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

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

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

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

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

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

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

Witness Parcell further testified that the comparable earnings method normally examines the experienced and/or projected return on book common equity. The logic for examining returns on book equity follows from the use of original cost rate base regulation for public utilities, which uses a utility's book common equity to determine the cost of capital. This cost of capital is, in turn, used as the fair rate of return, which is then applied (multiplied) to the book value of rate base to establish the dollar level of capital costs to be recovered by the utility. This technique is thus consistent with the rate base rate of return methodology used to set utility rates. Witness Parcel applied the comparable earnings methodology by examining realized rate of returns on equity for the Hevert and Parcell groups of proxy companies, as well as unregulated companies, and evaluated investor acceptance of these returns by reference to the resulting market-to-book ratios. Witness Parcell used the experienced rates of return on equity of the two proxy groups of utilities for the years 2002–2008 (the most recent business cycle) and 2009-2016 (the current business cycle) and projected ROE's for 2017, 2018, and 2020–2022 (the time periods estimated by Value Line). He testified that his results indicate that historic rates of return on equity of 9.4% to 11.0% have been adequate to produce market to book ratios of 141% to 159% for the groups of utilities. Furthermore, projected rates of return on equity for 2017, 2018, and 2020–2022 are within a range of 9.8% to 10.6% for the utility groups. These relate to market to book ratios of 176% or greater. He also noted that the rates of return on equity and market to book ratios of his proxy group, which all range over $20 billion in market value exceed those of witness Hevert's proxy group, which are not selected based upon size.

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

Witness Parcell testified in support of the 9.9% rate of return on equity in the Stipulation. Witness Parcell explained that the Stipulation allows an overall rate of return of 7.09% based on a 9.9% rate of return on equity and a capital structure of 52% equity and 48% long-term debt. Witness Parcell explained that the stipulated rate of return on equity is identical to the Commission's recent decisions in Dominion North Carolina Power's (DNCP) rate case, Docket No. E-22, Sub 532 (DNCP Rate Order). The overall rate of return in the Stipulation is lower than the Company requested. Witness Parcell also explained that the 9.9% rate of return on equity falls within the range of his comparable earnings analysis.

Public Staff witness Parcell testified that in his experience, settlements are generally the result of good faith "give-and-take" and compromise-related negotiations among the parties of utility rate proceedings, involving the utility and other parties. He testified that it was also his understanding that settlements, as well as the individual components of the settlements, are often achieved by the respective parties' agreements to accept otherwise unacceptable individual aspects of individual issues in order to focus on other issues. He testified it was his understanding that the proposed Stipulation is "global," except to the "Coal Ash" and storm cost issues in this proceeding.

Witness Parcell testified that it remains his position that should this be a fully litigated proceeding, he would continue to recommend a capital structure with 50% common equity and 50% long-term debt, a rate of return on equity of 9.20% (approximate mid-point of his range of 8.85% to 9.50%), and a cost of debt of 4.05%. However, given the benefits associated with entering a settlement, it was his view that the cost of capital components of the Stipulation are a reasonable resolution of otherwise contentious issues.

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

With respect to the rate of return on equity component of the Stipulation, witness Parcell testified that DEP requested a rate of return on equity of 10.75%, which witness Parcell stated in his direct testimony was well above industry norms in recent years. He proposed a 9.2% rate of return on equity (i.e., approximate mid-point of a rate of return on equity range of 8.85% to 9.50%, which was derived from his DCF model results of 8.85% and his comparable earnings results of 9.50%). Public Staff witness Parcell testified that while he continues to believe his specific 9.2% rate of return on equity recommendation is appropriate at this time, the upper end of his comparable earnings range of 9.0% to 10.0% contains the 9.9% Stipulation rate of return on equity level. He also stated that a 9.9% rate of return on equity is 0.70% above his 9.2% recommendation and is 0.85% below DEP's 10.75% rate of return on equity request. As a result, the 9.9% rate of return on equity in the Stipulation is a "compromise" between DEP's and the Public Staff's respective proposals. The 9.9% rate of return on equity also reflects a reduction from the 10.2% authorized in DEP's last rate proceeding.

Witness Parcell testified that he had employed the comparable earnings method in virtually all of his cost of capital analyses going back to 1972. He testified the comparable earnings analysis is based on the opportunity cost principal and is consistent with and derived from the Bluefield and Hope decisions of the U.S. Supreme Court, which are recognized as the primary standards for the establishment of a fair rate of return for a regulated public utility. The comparable earnings method is also consistent with the concept of rate base regulation for utilities, which employs the book value of both rate base and the capital financing rate base. He testified that his comparable earnings analyses considers the recent historic and prospective rates of return on equity for the groups of proxy utilities companies utilized by himself and DEP witness Hevert. He testified that his conclusion of 9.0% to 10.0% reflects the actual rates of return on equity of the proxy companies, as well as the market-to-book ratios of these companies. Witness Parcell further testified that in the recent DNCP rate proceeding, Docket No. E-22, Sub 532, Order dated December 22, 2016, DNCP and the Public Staff agreed to a settlement with a common equity ratio of 51.75% (versus the requested actual common equity ratio of 53.92%) and a rate of return on equity of 9.9% (versus the 10.5% requested). The Commission approved the cost of capital components of that proposed settlement. Witness Parcell testified that the equity ratio and rate of return on equity in the proposed Stipulation in the current DEP proceeding are consistent with those of the DNCP proceeding.

DEP witness Hevert also testified in support of the Stipulation on the agreed-upon rate of return on equity, capital structure, and overall rate of return contained in the Stipulation. Witness Hevert testified that although the stipulated rate of return on equity is below the lower bound of his recommended range of 10.25%, he recognized the Stipulation represents negotiations among DEP and the Public Staff regarding otherwise contested issues. He testified that the Company has determined that the terms of the Stipulation, in particular the stipulated rate of return on equity and equity ratio, would be viewed by the rating agencies as constructive and equitable, and that he understands and respects that determination.

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

Witness Hevert testified that he considered the stipulated rate of return on equity in the context of authorized returns for other vertically integrated electric utilities. He testified that from January 2014 through November 2017, the average authorized rate of return on equity for vertically-integrated electric utilities was 9.85%, only five basis points from the stipulated rate of return on equity. Of the 75 cases decided during that period, 31 included authorized returns of 9.90% or higher.

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

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

Within RRA's ranking system, North Carolina is rated "Average/1," which witness Hevert testified falls in the top one-third of the 53 regulatory commissions ranked by RRA. Witness Hevert testified that the stipulated rate of return on equity falls 13 to 14 basis points below the mean and median authorized rate of return on equity, respectively, for jurisdictions that are comparable to North Carolina's constructive regulatory environment, and 37 basis points above the median return authorized in less supportive jurisdictions. Taken from that perspective, the stipulated rate of return on equity is a reasonable, if not somewhat conservative measure of DEP's cost of equity.

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

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

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

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

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

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

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

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

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

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

Witness O'Donnell testified that for his CAPM, he used for the risk-free rate and the current 30-year Treasury bond yields of 2.9%. He expected the current interest rate environment to remain relatively stable for many years to come, citing statements by Federal Reserve Chairperson Janice Yellen. "Yellen Says Forces Holding Down Rates May Be Long Lasting," Barrons, June 16, 2016. The beta he used was his proxy group was 0.72 and the beta for Duke Energy Corporation was 0.60.

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

Commercial Group witnesses Chriss and Rosa testified that the average of 111 reported electric utility rate case rates of return on equity authorized by commissions to investor-owned utilities in 2014, 2015, 2016 and year-to-date 2017 was 9.65%. Witnesses Chriss and Rosa further testified that for the group reported by SNL Financial in Commercial Group Exhibit CR-3, the average rate of return on equity for vertically integrated utilities authorized from 2014 through present is 9.79%. They further testified that there is a continuing declining trend in authorized rates of return on equity for vertically integrated utilities over this time period. The average rate of return on equity authorized for vertically integrated utilities in 2014 was 9.92%; in 2015, 9.75%; in 2016, 9.77%; and so far in 2017, 9.70%.

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

CIGFUR witness Phillips did not perform cost of capital analyses. He testified that DEP's requested rate of return on equity of 10.75% is excessive and should be rejected. He stated that DEP's current authorized rate of return on equity is 10.2%, which was authorized in the Commission's 2013 DEP Rate Order issued on May 30, 2013. Witness Phillips testified that costs of capital have declined since DEP's last rate case. Every quarter, Regulatory Research Associates, an affiliate of SNL Financial, updates its Major Rate Case Decisions report that covers electric and natural gas utility rate case outcomes. Specifically, this report tracks the authorized rates of return on equity resulting from utility rate cases. The most recent report, updated through June 30, 2017, shows that the national average authorized rate of return on equity for electric utilities in the first six months of this year is 9.61%, nearly 60 basis points below DEP's currently authorized rate of return on equity. Witness Phillips concluded that DEP's current approved rate of return on equity, and definitely its requested rate of return on equity, are significantly above the current market cost of equity. He recommended that the Commission authorize a rate of return on equity that does not exceed the national average of9.61%.

2. Discussion of Rate of Return Evidence and Conclusions

In a fully contested rate case such as, for example, the 2012 DNCP rate case, there will almost inevitably be conflicting rate of return on equity expert testimony. Even in a partially settled case, the Commission may be faced with conflicting rate of return on equity expert witnesses whose testimony, in accordance with CUCA I and Cooper I, requires detailed consideration and, as necessary, evaluation by the Commission of competing methodologies, opinions, and recommendations. These were the circumstances in DEC's 2011 rate case, Docket No. E-7, Sub 989, which resulted in the Cooper I decision, as well as the DEP Sub 1023 Rate Case. In both of those cases rate of return on equity expert testimony from CUCA witness O'Donnell provided an alternate rate of return on equity analysis that pegged the utility's cost of capital at an amount lower than the settled rate of return on equity. The Supreme Court in Cooper I faulted the Commission for not making explicit its evaluation of this testimony, and, thus, the Commission in the 2013 DEP Rate Order made an express evaluation of witness O'Donnell's testimony in accordance with the Cooper I decision.

The Commission determines the appropriate rate of return on equity based upon the evidence and particular circumstances of each case. However, the Commission believes that the rate of return on equity trends and decisions by other regulatory authorities deserve some weight, as (1) they provide a check or additional perspective on the case-specific circumstances, and (2) the Company must compete with other regulated utilities in the capital markets, meaning that a rate of return on equity significantly lower than that approved for other utilities of comparable risk would undermine the Company's ability to raise necessary capital, while a rate of return on equity significantly higher than other utilities of comparable risk would result in customers paying more than necessary. In this connection, the analysis performed by Commercial Group witnesses Chriss and Rosa, as modified by witness Hevert, is instructive. Witnesses Chriss and Rosa noted that according to data from SNL Financial for 2014 through the 2017 hearing date, authorized rates of return on equity across the country for vertically-integrated electric utilities have been in the range of 9.20% to 10.55%. Witnesses Chriss and Rosa calculated the mean authorized rate of return on equity for vertically-integrated utilities like DEP to be 9.79%. Witness Hevert, in commenting upon and evaluating their testimony in his Rebuttal Testimony, refined their analysis and presented his findings in Exhibit RBH-R21 to add in jurisdictional rankings. Doing so results in a rate of return on equity range from 9.70% to 10.55%, with a median of 10.14%. (Tr. Vol. 8, pp. 158-59.) The Settlement rate of return on equity is, of course, within that range, and actually below the median of that range. As witness Hevert's settlement testimony notes, "since 2014, the average authorized Return on Equity for vertically integrated electric utilities has been 9.85%, only five basis points from the Settlement rate of return on equity. Among jurisdictions that, like North Carolina, are seen as having constructive regulatory environments, the average authorized ROE [rate of return on equity] was 10.03%, 13 basis points above the 9.90% Settlement ROE [rate of return on equity]." (Id. at 330.) Accordingly, the evidence presented concerning other authorized rates of return on equity, when put into proper context, lends substantial support to the stipulated 9.9% rate of return on equity level.

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

3. Evidence of Impact of Changing Economic Conditions on Customers

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

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

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

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

DEP witness Hevert testified extensively on economic conditions in North Carolina. He testified that unemployment has fallen substantially in North Carolina and the U.S. since late 2009 and early 2010, when the rates peaked at 10.00% and 11.30%, respectively. By February 2017, the unemployment rate had fallen to one-half of those peak levels: 4.70% nationally, and 5.10% in North Carolina. Since DEP's last rate filing in 2012, the unemployment rate in North Carolina has fallen from 9.00% to 5.10%.

Witness Hevert testified that with respect to GDP there also has been a relatively strong correlation between North Carolina and the national economy (approximately 67.00%). Since the financial crisis, the national rate of growth at times (during portions of 2010 and 2012) outpaced North Carolina. Since the third quarter of 2015, however, North Carolina has consistently exceeded the national growth rate. He testified that as to median household income, the correlation between North Carolina and the U.S. is relatively strong (nearly 86.00% from 2005 through 2015). Since 2009 (that is, the years subsequent to the financial crisis), median household income in North Carolina has grown at a faster annual rate than the national median income.

Witness Hevert testified as to the seasonally unadjusted unemployment rates in the counties served by DEP. At the unemployment peak, which occurred in late 2009 into early 2010, the unemployment rate in those counties reached 12.65% (1.65 percentage points higher than the State-wide average); by February 2017 it had fallen to approximately 5.60% (0.60 percentage points higher than the State-wide average). Since DEP's last rate filing in 2012, these counties' unemployment rates have fallen by over 4.00 percentage points.

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

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

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

b. Evidence Introduced During Public Hearings and Further Conclusions

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

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

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

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

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

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

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

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

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

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

Economic conditions existing during the test year, at the time of the public hearings, and at the date of this Commission Order affect not only the ability of DEP's consumers to pay electric rates, but also the ability of DEP to earn the authorized rate of return during the period rates will be in effect. Pursuant to G.S. 62-133, rates in North Carolina are set based on a modified historic test period.[1] A component of cost of service as important as return on investment is test year revenues.[2] The higher the level of test year revenues the lower the need for a rate increase, all else remaining equal. Historically, and in this case, test year revenues are established through resort to regression analysis, using historic rates of revenue growth or decline to determine end of test year revenues.

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

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

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

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

expenses must be paid, depreciation must be funded, taxes must be paid, and the utility must pay interest on the debt it incurs. To the extent revenues are insufficient to cover the entire cost of service, the shortfall reduces the return to the equity investor, last in line to be paid. When this occurs, the utility's realized, or earned, return is less than the authorized return.

This phenomenon, caused by incurrence of higher costs prior to the implementation of new rates to recover those higher costs, is commonly referred to as regulatory lag. Just as the Commission confronts constitutional and statutory restrictions in making discrete decrements to rate of return on equity to mitigate the impact of rates on consumers, it also confronts statutory constraints on its ability to adjust test year revenues to mitigate for regulatory lag. The Commission, in its expert experience and judgment and based on evidence in the record, is aware of the effects of regulatory lag in the existing economic environment. However, just as the Commission is constrained to address difficult economic times on customers' ability to pay for service by establishing a lower rate of return on equity in isolation from the many subjective determinations that must be made in a general rate case, it likewise does not address the effect of regulatory lag on the Company by establishing a higher rate of return on equity. Instead, in setting the rate of return, the Commission considers both of these negative impacts in its ultimate decision fixing DEP's rates. The Commission keeps all factors affected by current economic conditions in mind in the many subjective decisions it makes in establishing rates. In doing so in the case at hand, the Commission has accepted the stipulated 9.9% rate of return on equity in the context of weighing and balancing numerous factors and making many subjective decisions. When these decisions are viewed as a whole, including the decision to establish the rate of return on equity at 9.9%, the Commission's overall decision fixing rates in this general rate case results in lower rates to consumers in the existing economic environment.

Consumers pay rates, a charge in cents per kWh or per kW for the electricity they consume. Investors are compensated by earning a return on the capital they invest in the business. Consumers do not pay a rate of return on equity. Investors are paid in dollars. In this case DEP filed rate schedules that would have produced annual revenues of $3,560,767,000. This is the amount ratepayers would pay. These revenues, pursuant to the Application, would have produced $625,570,000 in return on investment. Of this amount $463,224,000 was the return that would have been paid to equity investors, the "return on equity." Pursuant to the Application the "rate of return on equity" financed portion of the investment (as distinguished from the "return on equity") would have been 10.75%.

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

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

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

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

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

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

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

In this case DEP originally requested a retail revenue increase of $477 million, or a 14.9% increase in annual revenues. The Commission has examined the Company's application and supporting testimony and exhibits and Form E-1 filings seeking to justify this increase. The Public Staff and DEP reached a Stipulation that resulted in reducing the retail revenue increase sought by the Company by approximately $73 million. The Public Staff represents the using and consuming public, including those having difficulty paying their bills. The Public Staff representatives attended all of the hearings held across the state to receive customers' testimony. The Public Staff has a staff of expert engineers, economists, and accountants who investigate and audit the Company's filings. The Public Staff must recommend rates consumers should pay and the return on investment equity investors should receive. The Public Staff considers all factors included in cost of service. In recent years, the Public Staff and the utilities have entered into settlements resolving the issues so as to avoid at least part of the substantial rate case expense customers otherwise would pay. This process is favored by financial analysts and rating agencies because it reduces delay and enhances predictability, thereby creating a constructive, credit supportive, regulatory environment ultimately reflected favorably in investors' required cost of capital. Intervenors who generally represent narrow segments or classes of ratepayers seldom enter into these settlements, though often times they do not oppose them.

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

<u>Summary and Conclusions on the Rate of Return on Equity</u>

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

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

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

DEP witness Hevert's risk premium analysis is credible, probative, and entitled to substantial weight. His risk premium was calculated as the difference between the authorized rate of return on equity and the then-prevailing level of long-term 30-year Treasury yield. He then gathered data for 1,508 electric utility rate proceedings between January 1980 and March 31, 2017. The Commission approved rate of return on equity of 9.9% is 10 basis points below witness Hevert's risk premium's implied rate of return on equity range of 10.0% to 10.32%.

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

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

In its post-hearing brief, the AGO contends that establishing an 8.48% rate of return on equity is supported by stock market data showing what investors require under current economic conditions, fairly balances the interests of investors and consumers, reduces the revenue requirement by another $96.1 million per year, and is supported by the results of the DCF analyses performed by the expert witnesses. (Tr., Vol. 13, p. 126.) In addition, the AGO submits that DEP has not met its burden of proof that the9.9% rate of return on equity proposed in the Stipulation fixes a reasonable return given the low cost of equity capital in current markets.

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

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

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

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

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

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

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

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

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

The Commission has carefully evaluated the DCF analysis recommendations of witnesses Parcell, Hevert, Polich, and O'Donnell, and the Commission gives minimal weight to these analyses. As shown on Commercial Group's Exhibit CR-3, the lowest Commission approved rate of return on equity for a vertically integrated electric company for the period of 2014 through the hearing in 2017 was 9.2%. Witness Parcell's specific DCF result was 8.85%, witness Polich's was 8.48%, and the mid-point of witness O'Donnell's was 8.25%. The average of Hevert's constant growth DCF means was 8.92%, and the mid-point of the range of witness Hevert's Multi-Stage DCF analysis was 9.0%. The Commission considers all of these DCF results to be outliers, being well below the lowest vertically-integrated rate of return on equity of 9.2%. The Commission determines that all of these DCF analyses in the current market produce unrealistic low results.

The Commission gives no weight to any of the witnesses' CAPM analyses. The analyses of witness Parcell with a mid-point of 6.4% is unrealistically low, and witness Parcell agreed as much in his testimony. The CAPM analysis of witness O'Donnell resulted in a CAPM rate of return on equity mid-point of 6.05%, which is an outlier well below the 9.2% previously discussed. Witness Polich's CAPM weighted median rate of return on equity of 7.56% is also an outlier and unrealistically low. DEP WitnessHevert's CAPM range of 9.15% to 11.49% is also an outlier and upwardly biased due to his use of the near-term projected 30-year Treasury interest rate of 3.52%, which witness Parcell testified greatly exceeds the current level of long-term Treasury of about 2.8%. Witness Hevert's risk premium component of this CAPM uses a constant growth DCF for the S&P 500 companies using analysts projected earnings per share forecasts as the growth component. Witness Hevert's DCF dividend growth, component based solely on analysts' earnings per share growth projections, without consideration of any historical results, is upwardly biased and unreliable.

The rate of return on equity testimonies of Commercial Group witnesses Chriss and Rosa focused on the commission-approved rates of return on equity authorized for vertically-integrated electric utilities in 2014, 2015, 2016, and year-to-date 2017 listed in Commercial Group Exhibit CR-3. The Commission gives weight to this testimony only as a check on the Commission's approved 9.9% rate of return on equity and to evaluate outlier rate of return on equity recommendations. CIGFUR witness Phillips' testimony focused on the RRA report Major Rate Case Decisions. The 9.61% average authorized rate of return on equity for electric utilities included both vertically-integrated electric utilities and distribution-only electric utilities. Since DEP is a vertically-integrated electric utility, the Commission gives witness Phillips' rate of return on equity testimony limited weight regarding authorized rates of return on equity for distribution-only electric utilities. Rather, as noted above, recently authorized rates of return on equity for vertically-integrated electric utilities since 2014 average 9.85%, and in jurisdictions with constructive regulatory environments average 10.03%, and serve as a better check.

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

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

Capital Structure

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

Witness De May testified that the Company's "specific debt/equity ratio will vary over time, depending on the timing and size of debt issuances, seasonality of earnings, and dividend payments to the parent company." (Tr. Vol. 8, p. 29.) As of the end of the test year, the actual regulatory capital structure[1] was 52.5% equity and 47.5% debt (Id. at 44), and the 13-month average equity ratio was 53.5%. (Id.) This average equity ratio was maintained by DEP through June 2017. (Id.) The 52/48 capital structure agreed to in the Stipulation represents a compromise between the Company's 53/47 position and the Public Staff's recommendation of a 50/50 capital structure. Both witness Parcell, for the Public Staff, and witness De May, for the Company, supported the agreed upon 52/48 ratio. (Tr. Vol. 14, pp. 109-10 (Parcell) (52/48 ratio reflects a reasonable compromise, and also "incorporate[s] a reduction" from the Company's currently authorized 53/47 ratio); Tr. Vol. 8, p. 54 (De May).) De May indicates that the "stipulated capital structure is reasonable when viewed in the context of the overall Partial Settlement," and it would be positively viewed by the ratings agencies that set the Company's credit ratings. (Id.) Witness Hevert's settlement testimony also supported the stipulated 52/48 capital structure. (Id. at 330-31.)

CUCA witness O'Donnell and AGO witness Polich recommend that the Commission reject the Company's capital structure proposal and instead advocate a 50/50 hypothetical structure. Witness Polich provided no analysis to support his recommendation. He merely asserts, without any cited evidence, that "[i]n the utility industry, it is common to target the percentage of debt and equity at 50% each." (Tr. Vol. 13, p. 117.) As witnesses De May and Hevert demonstrate in their rebuttal testimony, this assertion is simply wrong. (Tr. Vol. 8, p. 41 (De May); id. at 242; Ex. RBH-R19 (Hevert).) Further, witness Polich states that the reason the Commission should move to an artificial 50/50 capital structure is "to lower rates." (Tr. Vol. 13, p. 118.) But as witness De May indicates, "[s]etting an artificial capital structure simply for the purpose of lowering rates presents great risk." (Tr. Vol. 8, p. 48.) In the 2013 DEC Rate Case, for example, the AGO argued that a 50/50 capital structure should be implemented for utility, but, like witness Polich in this case, provided "no probative or persuasive evidence suggesting that a 50/50 capital structure is in fact appropriate." (2013 DEC Rate Order, at 52.) The Commission rejected the AGO's argument because that argument did not "recognize the pitfalls were the Commission to order in this case a capital structure at odds with the structure supported by the testimony of the expert witnesses and in line with the Company's actual capital structure in recent years." (Id. at 53.)

Those pitfalls are readily apparent. First, as witness De May stated, "a 50/50 capital structure would place pressure on ... [the Company's "A" level credit rating] by affecting DEP's credit metrics. It would also likely negatively impact the ratings agencies' assessment of qualitative factors, in that movement away from the optimum 53/47 capital structure will likely be viewed as a step away from a credit supportive regulatory environment." (Tr. Vol. 8, p. 47.)[2] Second, as the Commission has already held in this case in connection with its ROE discussion, the ratings

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

[2] Witness De May indicated in his Settlement Testimony that the slight move away from the 53/27 proposed capital structure represented by the Stipulation would likely still be viewed as credit supportive by the ratings agencies. (Tr. Vol. 8, p. 54.) In any event, a 50/50 structure is a far cry from a 52/48 structure – each percentage point of reduction in equity represents a $10 million reduction in revenue requirement, which is certainly significant in evaluating the effect of further reduction on the Company's credit metrics.

agencies' "assessment of qualitative factors" is vitally important to the maintenance of the Company's credit quality and to the cost of capital:

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

2013 DEP Rate Order, at 37 (emphasis added).

Unlike witness Polich, witness O'Donnell provided an analysis purporting to support his 50/50 capital structure recommendation, but that analysis is seriously flawed. The principal rationale for witness O'Donnell's 50/50 recommendation is his comparison of capital structures of publicly-traded holding companies, not operating utility companies. (Tr. Vol. 15, pp. 196-97.) This Commission has previously commented on and rejected the use of parent company structures as opposed to operating company structures in determining the operating utility's appropriate equity/debt ratio. See Order Granting General Rate Increase and Approving Amended Stipulation, Docket No. E-7, Sub 909 (December 7, 2009) (2009 DEC Rate Order), at 27-28. Parent and operating companies simply do not necessarily have the same capital structures, because, as witness Hevert points out, financing at each level is driven by "the specific risks and funding requirements associated with their individual operations." (Tr. Vol. 8, p. 239.) In addition, witness Hevert notes, the use of the operating subsidiary's actual capital structure – that is, the capital actually funding the utility operations that provide service to customers – is entirely consistent with precedent of the Federal Energy Regulatory Commission (FERC), so long as three criteria are met: the operating subsidiary (1) issues its own debt without guarantees, (2) has its own bond rating, and (3) has a capital structure within the range of capital structures for comparable utilities. (Id.) Here all three criteria are met. DEP does issue its own debt and is rated separately from its parent company, and the evidence presented by witnesses De May and Hevert shows that its capital structure is generally consistent with that of other operating companies, especially vertically-integrated companies. (Id. at 41 (De May); Id. at 316 (Hevert).)

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

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

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

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

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

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

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

Cost of Debt

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

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

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

No intervenor offered any evidence for a debt cost below 4.05%. The Commission, therefore, finds and concludes that the use of a debt cost of 4.05% is just and reasonable to all parties in light of all the evidence presented.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 25

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

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

- Residential 1.933 cents per kWh
- Small General Service 2.088 cents per kWh

- Medium General Service 2.431 cents per kWh
- Large General Service 2.253 cents per kWh
- Lighting 0.596 cents per kWh

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

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

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

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

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

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

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

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 26

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

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

In his pre-filed testimony, Public Staff witness Metz recommended adjustment to the materials and supplies component of cash working capital to reflect a 30-day coal inventory based on a 70% full load burn. (Id. at 304.) He testified that a 70% capacity factor represents a reasonable estimate of the Company's coal fleet performance during peak conditions, though he would expect that the Company would adjust its inventory based on anticipated seasonal needs. (Id. at 304-05.) Witness Metz based his recommendation of 30 days on the fact that the Company has operated with 40 days or less of inventory in the past, as well as his belief that the Company "is fully capable of operating its plants with 30 days or less of coal inventory." (Id. at 306.)

In his rebuttal testimony, Company witness Miller explained that the Company actually contemplated requesting an increase in the full load burn inventory target to enable the Company to respond to un-forecasted increases in coal generation demand, given the increased volatility in coal generation due to factors such as fluctuating natural gas prices and weather-driven demand. (Tr. Vol. 10, p. 37.) However, the Company determined that it was prudent to continue to operate under the current 40-day full load burn inventory target and made a pro forma adjustment reducing its actual coal inventory at the end of the Test Period to reflect a targeted 40-day, 100% full load burn. (Id.)

Witness Miller testified that adopting witness Metz's recommendation of 30-day coal inventory based on a 70% full load burn could lead to negative supply, delivery, and operational impacts. (Id. at 36.) He testified further that this recommendation fails to contemplate the factors that impact a reliable fuel supply, including volatility in coal generation demand, delivery and/or supply risks, and generation performance. (Id. at 38.) In particular, he noted that witness Metz's recommendation assumes there will be ample amounts of coal available during higher demand periods and does not contemplate the increased demand from other utilities during the same period of increased demand being experienced by the Company. (Id.) According to witness Miller, if DEP is unable to dispatch cost-competitive coal generation during peak demand due to unreliable inventory levels, it will have to seek alternatives such as dispatching higher cost generation, paying higher prices for fuel, or purchase power. (Id. at 45.) As such, having unreliable coal inventory levels could result in unfavorable impacts on customers. (Id.)

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

In the Stipulation, the Public Staff and DEP agreed that for purposes of settlement, the Company may set carrying costs included in base rates assuming a 35-day coal inventory at 100% capacity factor (full load burn), and that a coal inventory rider should be allowed to manage the transition. More specifically, the Stipulating Parties propose that this increment rider shall be effective on the same date as new base rates approved in this proceeding and continuing until inventory levels reach a 35-day supply to allow the Company to recover the additional costs of carrying coal inventory in excess of a 35-day supply (priced at $76.11 per ton). The rider will terminate the earlier of (a) January 30, 2020 or (b) the last day of the month in which the Company's actual coal inventory levels return to a 35-day supply on a sustained basis.[1] The Stipulation provides that for this purpose, three consecutive months of total coal inventory of 37 days or below will constitute a sustained basis. The Company will adjust this rider annually, concurrently with DEP's DSM/EE Rider, REPS Rider, JAAR Rider, and Fuel Adjustment Rider, and any over- or under-collection of costs experienced as a result of this rider shall be trued up in

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

that annual rider filing. For purposes of the coal inventory rider, the Stipulating Parties agree that interest on any under- or over-collection shall be set at the Company's net-of-tax overall rate of return, as approved by the Commission in this proceeding. Finally, the Company agreed to conduct an analysis in consultation with the Public Staff demonstrating the appropriate coal inventory level given market and generation changes since the Company's last rate case (Docket No. E-2, Sub 1023), with such analysis to be completed by December 31, 2018.

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

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

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

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

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

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

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

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

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

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

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

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

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 29

The evidence supporting this finding of fact and conclusions is contained in the Stipulation, the testimony of DEP witnesses Fountain and Simpson, Public Staff witness Floyd, CUCA witness O'Donnell, EDF witness Alvarez, and NCSEA witness Golin, and the entire record in this proceeding.

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

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

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

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

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

Public Staff witness Floyd reiterated that the Power/Forward initiative is not a part of this rate case. (Tr. Vol. 19, pp. 124-25.) However, he further states that should the Company seek recovery of the $18.2 million it has already spent on Power/Forward, it should only be permitted to recover the costs if DEP can demonstrate that the investment was cost-beneficial to customers.

(Id. at 126.) Witness Floyd also believes additional reporting is needed to allow the Commission to better understand Power/Forward and to quantify its benefits. Witness Floyd recommended that the Commission require DEP to include in its smart grid technology plan filings, required by Commission Rule R8-60.1, more detailed information. (Id. at 126-27.)

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

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

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

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

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

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

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

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

The AGO states that it fully supports and applauds DEP's commitment to planning for efficient and effective utility service for its customers, but that the issue is whether DEP has done the necessary work to determine whether this particular approach is a reasonable and prudent way to attack the problem of reliability and security of the grid. The AGO cites the testimony of Public Staff witness Floyd that "additional reporting is needed to allow the Commission to better understand Power/Forward Carolinas and to quantify its benefits. The extent of the planned investment and the potential impact on customer rates requires additional reporting, in order to assist the Commission and Public Staff in understanding Power/Forward Carolinas and evaluating its cost-effectiveness." (Tr. Vol. 19, p. 127.)

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

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

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

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

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

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 30

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Additionally, the Company entered into settlement agreements with Commercial Group and Kroger regarding rate design issues. Commercial Group and Kroger agreed to settle all issues with the Company, provided that, inter alia, the Stipulation between the Company and the Public Staff state that "the revenue increase applicable under Schedules MGS and SGS-TOU should strive to achieve approximately the same percentage increase in revenues under each schedule." (Kroger

Settlement 1; Commercial Group Settlement 2; Stipulation IV.F.3.d.) Moreover, as part of the Commercial Group Settlement, "DE Progress agrees that it shall work with interested commercial and industrial customers to investigate the issues with Rider SS that were raised in the direct testimony filed by the Commercial Group." (Commercial Group Settlement 2-3.)

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

Basic Customer Charge

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

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

NCSEA witness Barnes testified that the Company's proposed fixed customer charge increases are "extreme" and recommended that the current customer charges be maintained, or, alternatively, that the customer charges only be increased by the percentage increase in the overall revenue requirements adopted for each class. (Tr. Vol. 16, p. 49.) Specifically, NCSEA witness Barnes testified that the increased Residential BCC proposed by the Company was higher than other utilities and is, therefore, inappropriate. (Id. at 49-52.) Witness Barnes also argues that the proposed increases are inconsistent with the ratemaking principle of gradualism. (Id. at 52-53.)

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

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

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

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

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

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

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

Witness Deberry also opposed the increased residential BCC, testifying that it will affect already cost-burdened residents who struggle to afford housing costs. (Tr. Vol. 13, p. 214.) Witness Deberry explained that over half of all cost-burdened households are renters without the ability to make investments in energy efficiency. (Id. at 216.) She further explained that the increased BCC would reduce incentives from bill savings for landlords to include utility programs in their property management, and, thus, the costs of an increased BCC would be passed on to customers least able to afford it. (Id. at 219.) Similarly, witness Howat testified that increasing fixed customer charges causes disproportionate impacts to low-volume, low-income customers and discourages energy efficiency. (Tr. Vol. 13, p. 239.) Witness Howat testified that low-income households, and particularly low-income households of color, are at a heightened risk of loss of home energy service, and the increased threat of disconnection posed by the Company's rate increase proposes a threat to the health and safety of these customers and the larger community. (Id. at 247-49.)

In his rebuttal testimony, Company witness Wheeler responded to the arguments raised by these intervenors regarding the proposed increases to the BCCs. (Tr. Vol. 10, pp. 220-24.) First, he explained that "[i]t is important that the Company's rates reflect cost causation to minimize subsidization of customers within the rate class." (Id. at 220.) Witness Wheeler explained that "customer-related costs are unaffected by changes in customer consumption and therefore should be paid by each participant, regardless of their consumption." (Id.) He further explained that any customer-related revenue not recovered in the BCC is shifted to energy rates, which contrary to witness Wallach's assertion, actually results in high-usage customers subsidizing the rates of lower-usage customers. (Id.)

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

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

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

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

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

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

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

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

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

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

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

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

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

> (3a) To assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions. To that end, to require energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable, including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills;
>
> (4) To provide just and reasonable rates and charges for public utility services without unjust discrimination, undue preferences or advantages, or unfair or destructive competitive practices and consistent with long-term management and conservation of energy resources by avoiding wasteful, uneconomic and inefficient uses of energy;
>
> ***
>
> [6) To foster the continued service of public utilities on a well-planned and coordinated basis that is consistent with the level of energy needed for the protection of public health and safety and for the promotion of the general welfare as expressed in the State energy policy;
>
> ***
>
> (10) To promote the development of renewable energy and energy efficiency through the implementation of a Renewable Energy and Energy Efficiency Portfolio Standard (REPS) that will do all of the following:
>
> a. Diversify the resources used to reliably meet the energy needs of consumers in the State.
>
> b. Provide greater energy security through the use of indigenous energy resources available within the State.

c. Encourage private investment in renewable energy and energy efficiency.

d. Provide improved air quality and other benefits to energy consumers and citizens of the State.

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

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

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

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

AMI Enabled Rates

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

Additionally, EDF witness Alvarez testified about various AMI-enabled services that he argues offer significant customer and environmental benefit potential. (Tr. Vol. 7, pp. 152-54.) Company witness Wheeler responded that the Company is considering all of the initiatives suggested by witness Alvarez. (Tr. Vol. 10, p. 225.) Specifically, the Company already offers some time varying rates, is evaluating introduction of various usage alerts as part of its Enhanced Basic Services initiative, and has explored residential prepayment options through two different pilot programs. (Id. at 226.) Witness Wheeler also responded to witness Alvarez's suggestion that a collaborative would be beneficial in developing time-varying rate designs by reiterating that the Company highly values customer input in evaluating both current and future rate designs. (Id. at 227.) He explained that the Company routinely discusses its rate design with members of the Public Staff and customers, and that it is preferable that such input be received on an on- going basis rather than awaiting a group meeting to be certain this guidance is considered in the decision-making process with respect to future rate designs and requirements for supporting infrastructures. (Id. at 227-28.)

Witness Wheeler further explained why it would be premature to offer a specific AMI-enabled rate design in this proceeding. (Tr. Vol. 10, p. 227.) In addition to the fact that the AMI technology and new billing system infrastructure has not been implemented yet, he testified that it is important to evaluate each rate design in conjunction with other demand response options that seek to shift customer consumption. (Id.) For example, witness Wheeler explained that residential appliance control is an effective tool to reduce air conditioning load during system peak conditions which would potentially be the same load shifted by a residential critical peak pricing or peak time rebate program. (Id.) He explained that all customer options need to be evaluated to achieve the most dependable load response at the lowest cost to ratepayers. (Id.)

The Commission agrees that it is premature to offer specific AMI-enabled rate designs in this proceeding since the infrastructure underlying such rate design is not yet available. The Commission concludes that if and when DEP's AMI technology and new billing systems are implemented, the Company will be able to evaluate all customer options in order to achieve a rate design that provides the most cost-effective and dependable service to ratepayers.

TOU

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

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

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

SGS-TOU

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

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

In its post-hearing Brief, Commercial Group contends that the various class cost of service studies (CCOSS) show that the Medium General Service (MGS) class provides above-average returns to DEP, as it did under the different CCOSS methods following the 2013 rate case

(Tr. Vol. 11 p. 33), and, thus, the MGS class is subsidizing other ratepayer classes. DEP proposed to allocate any revenue increase to rate classes on the basis of rate base, and then adjust the increase each class receives in order to produce a 25% reduction in each class's variance from the overall average rate of return. (Tr. Vol. 7, p. 98 (Chriss/Rosa, citing Bateman Direct at 10.)) Commercial Group states that it does not take issue with this gradual approach to class revenue allocation, except if the Commission grants the proposed JRR. In such event, the Commission should set LGS rates at cost in order to avoid a double subsidy by MGS customers. (Tr. Vol. 7, p.100 (Chriss/Rosa)) Otherwise, according to Commercial Group, MGS ratepayers would be forced to pay one subsidy to the LGS and other ratepayer classes and another subsidy to LGS industrial customers under the JRR, which would be both unjust and unreasonable. Commercial Group also notes that in the Stipulation and in its settlement with DEP the MGS class subsidy burden was recognized by providing that the SGS-TOU rate schedule (which falls within the MGS class) should receive the same overall revenue increase percentage as does the MGS rate schedule. Further, to ensure a more equitable impact for the MGS class, Commercial Group and DEP agreed that the revenue increase applicable under Schedules MGS and SGS-TOU should strive to achieve approximately the same percentage increase in revenues under each schedule. Commercial Group maintains that the Commission should adopt this reasonable resolution.

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

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

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

LGS-TOU

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

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

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

Standby Service Rider

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

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

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

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

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

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

Street Lighting

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

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

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

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

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

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

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

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

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

Summary with Respect to Rate Design

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

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

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

As fully discussed above, the provisions of the Stipulation are the product of the give-and-take of settlement negotiations between DEP and the Public Staff. Comparing the Stipulation to DEP's Application, and considering the direct testimony of the Public Staff's witnesses, the Commission notes that the Stipulation results in numerous downward adjustments to the costs sought to be recovered by DEP. Further, the Commission observes that there are provisions of the Stipulation that are more important to DEP, and, likewise, there are provisions that are more important to the Public Staff. For example, the Public Staff was intent on reducing the cost recovery for DEP's Zero Liquid Discharge project at the Mayo plant and for the Sutton combustion turbine project. Further, the Public Staff was resistant to the substantial increase in the residential basic customer charge proposed by DEP. Likewise, DEP was intent on maintaining the depreciation rates set in its Depreciation Study. Nonetheless, working from different starting points and different perspectives, the Stipulating Parties were able to find common ground and achieve a balanced settlement.

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

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

Therefore, the Commission approves the Stipulation in its entirety. In addition, the Commission finds and concludes that the Stipulation is entitled to substantial weight and consideration in the Commission's decision in this docket. Further, the Commission concludes that the three settlement agreements entered into by DEP with Commercial Group, Kroger, and NC Justice Center are in the public interest and should be approved in their entirety.

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

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

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

On December 16, 2016, in Docket No. E-2, Sub 1131, DEP filed a Petition for Accounting Order to Defer Incremental Storm Damage Expenses. In this petition the Company requested an accounting order to defer incremental storm costs incurred during 2016. In its petition, DEP requested that the Commission issue an Order allowing DEP to establish, net of the $12.7million[1] of storm cost expense already included in DEP's base rates, a regulatory asset and defer until its next rate case the incremental O&M storm expenses, the depreciation expense and carrying costs at DEP's weighted average cost of capital on the incremental capital cost, as well as the carrying costs on the deferred costs incurred in connection with these storms.

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

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

its work alongside many city, county, and state government agencies during a number of these storms.

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

1. That the Company only be allowed to defer storm expenses in excess of an amount of $27.4 million[1];
2. That no deferral of depreciation expense or return on undepreciated capital costs be allowed;
3. That no return on the deferred asset be allowed during the deferral period;
4. That DEP be required to start amortization of the deferred costs in October 2016; and
5. That the amortization period be extended from the three years proposed by the Company to 10 years.

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

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

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

DEP witness Bateman stated in her testimony that DEP had made a pro forma adjustment to normalize storm costs to an average level of costs that DEP has experienced over the last 10 years. She testified that the pro forma removed any storm costs from the 10-year average

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

calculation that were included in the Company's 2016 storm deferral request and instead includes an amortization of the deferred costs over a three-year period.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

The evidence supporting these findings of fact and conclusions is found in DEP's verified Application, DEP's Petition for an Order Approving a Job Retention Rider (JRR), filed on August 14, 2017, in Docket No. E-2, Sub 1153 (Petition), the testimony of Company witness Wheeler, the testimony of Public Staff witness McLawhorn, the testimony of other witnesses, the exhibits of witness Wheeler, and the entire record in this proceeding. The Commission takes judicial notice of the Company's Initial and Reply Comments filed in Docket No. E-100, Sub 73 where the Company outlined the conditions that led to the loss of industrial jobs and where the Commission issued establishing guidelines on December 8, 2015. (JRT Order)

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

Company witness Fountain testified that "[t]he Company's proposed JRR is designed to stem further loss of industry, industrial production and industrial jobs in DEP's service territory, which the Commission acknowledged as an important policy goal for North Carolina when it adopted the Guidelines for JRRs." (Tr. Vol. 6, p. 83.) DEP witness Fountain stated the goal of retaining industrial jobs in the state is important to not only the customers of the state, but to DEP. (Tr. Vol. 6, p. 19) Company witness Wheeler provided more detailed testimony in support of the Company's proposed JRR. Witness Wheeler explained that the JRR will benefit ratepayers by retaining North Carolina jobs and strengthening local economies thereby aiding the commercial and residential markets. (Tr. Vol. 10, p. 250.) Since 2014, 53 manufacturing facilities served by Duke Energy have ceased operation in North Carolina. (See Wheeler Rebuttal Ex. No. 2.) Witness Wheeler stated that the Company's Integrated Resource Plan Update, filed on September 1, 2017, in Docket No. E-100, Sub 147, demonstrates the continuing struggles of manufacturing in North Carolina. (Tr. Vol. 10, p. 245.) He testified that "[t]he Plan shows a steady decline in the number of industrial customers receiving electric service and our expectation [is] that even by 2023 industrial sales will still be below actual pre-recession sales realized in 2007." (Id.)

Witness Wheeler also explained the eligibility requirements for the proposed JRR. In order to be eligible for the proposed JRR, the customer must do all of the following: (1) use electric power as a principal motive power for the manufacture of a finished product, the extraction, fabrication or processing of a raw material, or the transportation or preservation of a raw material or a finished product; (2) perform an energy audit within six months, or verify an energy audit has been performed within the past 36 months; (3) verify the customer is considering the ability to shift production from its facility, is considering a need to reduce employment at its facility due in part to the cost of electricity, intends to reduce production due in part to the impact of the cost of electricity, or the customer's load is otherwise at risk. (Id. at 245–46.) Furthermore, in order to qualify for JRR, industrial customers must show that they (i) have or are considering the ability to shift production from their facilities to facilities in other states or countries; (ii) are considering a need to reduce the employment level at their facilities due in whole or in part to the impact of electricity cost; (iii) intend to reduce or are presently evaluating reduction of production levels or load due in whole or in part to the impact of electricity cost; or (iv) have load that is otherwise at risk of loss. (Petition at 5.) Additionally, eligible customers must have an aggregate electrical load of 3,000 kW or greater, in addition to other conditions described in the Petition and proposed JRR. (Id. at 246.)

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

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

CIGFUR witness Phillips also testified in support of the Company's proposed JRR. Witness Phillips testified that the Company's proposed JRR follows the Guidelines for Job Retention Tariffs issued by this Commission on December 8, 2015 in Docket E-100, Sub 73, that the proposed JRR is in the public interest, and recommended that the Commission approve it. (Tr. Vol. 7, p. 74.) In CIGFUR's Post-Hearing Brief, CIGFUR proposed one adjustment to the proposed JRR to exempt rider participants from funding cost recovery. (Br. pp. 4-5)

While the Public Staff is supportive of the JRR and believes that it is in the public interest, witness McLawhorn expressed several concerns regarding the proposed rider. (Tr. Vol. 18, p. 29.) He argues that there are no specific criteria designated for use by the Public Staff to evaluate customer employment and financial records to aid in evaluating an applicant's justification for seeking the JRR thus depriving the Public Staff of the ability to verify the truthfulness of the information. (Id. at 34.) He also opposed the Company's request for deferral accounting of the revenue loss and the Company's proposal for sharing the discount between the Company's shareholders and ratepayers. (Id. at 36.)

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

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

Despite these concerns, the Public Staff generally supports the Company's proposed JRR, concluding that the rate reduction it provides for industrial customers would "assist them in maintaining jobs and load in North Carolina." (Tr. Vol. 18, p. 30.) Witness McLawhorn also testified that the proposed JRR is not unduly discriminatory because it is designed to reach the largest industrial customers, who impact other commercial and residential customer classes. (Id. at 29.) He further states that the proposed JRR "provides for a balancing of benefits and costs between those customers eligible for [JRR] and those that will bear the reduction in revenue that result from implementation of the rider." (Id.) Lastly, he recommended that the impact of the rate discount be recovered from all ratepayers, including the customers eligible for the rate discount.

Commercial Group witnesses Chriss and Rosa testified in opposition to the DEP's proposed JRR. Witnesses Chriss and Rosa state that the proposed JRR fails to comply with Commission guidelines by limiting applicability to a subset of industrial customers and the rigor of verifying customer attestations is unclear. (Tr. Vol. 7, p. 108.) They further request that if the JRR is approved that it be extended to non-industrials that also provide jobs and have aggregate loads of 3,000 kW or greater. (Id. at 109.)

In its post-hearing Brief, Commercial Group notes that after DEP and the Public Staff entered into a Stipulation, Commercial Group negotiated and reached a settlement with DEP that resolved additional issues, but left outstanding and unresolved the Commercial Group's concerns regarding the JRR. Commercial Group submits that the JRR would violate G.S. 62-140(a) because it would unjustly discriminate among customers having an aggregate load of at least 3 MW based solely on whether the customer is an industrial customer. Commercial Group contends that this is a return to the Standard Industrial Classification (SIC) code distinctions that the Commission found discriminatory and rejected in prior proceedings. Commercial Group states that the Commission stated its concern in its final Order in DEC's 2011 rate case, Docket E-7 Sub 989, regarding the reasonableness and fairness of maintaining a rate differential based largely on labels such as the SIC codes. Commercial Group quotes G.S. 62-140(a), and states that the legal standard is not whether a public utility can subject a customer to an unreasonable prejudice or disadvantage if doing so would be an advantage to other customers or the utility. Rather, the legal standard is that the public utility cannot grant any unreasonable preference or subject any person to any unreasonable prejudice or disadvantage. Further, Commercial Group contends that industrial customers are not a separate class of service because both industrial and commercial customers are members of the same MGS and LGS classes, and that many non-industrial ratepayers in these classes have an aggregate load of at least 3 MW. (Tr. Vol. 7, p. 108.) According to Commercial

Group, where the JRR's only distinguishing characteristic is industrial status, the JRR remains as unlawful and unduly discriminatory as the preference for OPT industrial customers in the last two DEC rate cases, and the proposed Industrial Economic Recovery rider that the Commission previously rejected, and, therefore, the JRR as proposed should be rejected as well.

In addition, Commercial Group states that the proposed JRR definitions and parameters that DEP selected provide only an illusion of being reasonable criteria for determining which customers should receive a rate subsidy. As an example, Commercial Group contends that the applicant could simply state that it has at some time in the past thought about obtaining the ability to move a portion of its operations out of state, but the applicant need not presently have such ability, presently plan to move operations out of state, nor be in such financial condition that jobs would be lost but for a JRR subsidy. Commercial Group further notes that the applicant does not need to maintain existing levels of employment, but instead chooses a level of employment that it states it will maintain, even if the level is lower than its present level. Moreover, Commercial Group submits that the JRR eligibility criteria are so broad that they include gas pipelines, even though DEP states that it has no current pipeline customers. (Tr., Vol. 11, at p. 33)

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

Commercial Group also questions whether there will be a means to assess the effectiveness of the JRR. Commercial Group cites the testimony of Public Staff witness McLawhorn regarding the report that DEP will be required to file, and states that the report will not provide any reliable, independently verifiable information to determine the success or failure of the JRR. Based on the uncertainty of verifiable results from the JRR, Commercial Groups recommends that the Commission require DEP to bear 50% of the JRR costs, with any remaining cost to be recovered from ratepayers on a percentage of bill basis.

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

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

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

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

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

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

In the Stipulation, the Company and the Public Staff agreed that "the Company's proposed Job Retention Rider generally complies with the Commission's guidelines adopted in Docket No. E-100, Sub 73, but two issues remain to be decided upon by the Commission: (1) whether companies involved in the transportation or preservation of a raw material or a finished product (e.g., pipeline customers) should qualify; and (2) how or if the Job Retention Rider should be funded after the expiration of the initial year's $3.5 million shareholder contribution." (Stipulation p. 4 - Paragraph II(c).)

Except for the two unresolved issues stated above, the Stipulating Parties have agreed to the proposed JRR as described by witness Wheeler in his rebuttal testimony, and further agreed that JRR revenue credits shall be recovered through a JRR Recovery Rider (JRRR) from all retail customers concurrent with JRR implementation, which is anticipated to occur approximately six months following the Commission's decision. (Stipulation p. 15.) The Stipulation provides that JRR and JRRR revenues shall be reported to the Commission annually and the JRRR shall be reviewed and will be subject to adjustment annually coincident with the December fuel adjustment to match anticipated recovery revenues and true-up any past over-or under-recovery. (Stipulation pp. 15-16.) Additionally, due to the uncertain date of implementation, compliance tariffs shall be filed prior to implementation of the JRR Recovery Rider and customers shall be notified by bill insert or message upon implementation. (Id. at 16.)

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

Commercial Group, in its post-hearing Brief, submits that the JRR would violate 62-140(a) because it would unjustly discriminate among customers having an aggregate load of at least 3 MW based solely on whether the customer is an industrial customer. Commercial Group contends that this is a return to the SIC code distinctions that the Commission found discriminatory and rejected in prior proceedings.

The Commission finds and concludes that the Company's proposed JRR as modified by this Order is just and reasonable to all parties based on all of the evidence presented. The Commission finds that the continued loss of industrial jobs in DEP's service area would have a detrimental effect on the State. The Commission views the Company's proposed JRR as an effort to retain industrial jobs in North Carolina and concludes that implementation of the rider is in the public interest. As with other economic development tariffs previously approved by this Commission, approval of the JRR is based in part on an evaluation of the expected economic benefits resulting from the tariff. The Commission has considered the economic impact of the continuing decline of the North Carolina industrial base as well as the impact of the recovery rider on non- participating ratepayers, and concludes that the JRR strikes the appropriate balance between the two. The Commission concludes that by limiting the availability of the JRR to industrial customers, the Company has minimized the effect on non-participants while assisting the group of customers that are most in need of assistance. To further minimize the impact to non-participants and to achieve the goal of the JRR in the most cost- effective manner, the Commission shall limit the JRR to a one-year pilot, with the option of renewal for one additional year upon a showing that the JRR is achieving the intended objectives. Requiring the Company to show the Commission the effectiveness of the JRR in the rider proceeding removes many, if not all, concerns expressed by the Commercial Group and the Department of Defense regarding measurement and verification. This reduction in the number of years for the pilot to one-year with the opportunity for a second year allows the Commission and the parties to assess the health of industrial sector as a whole after one year on the JRR and if an additional year would be in the public interest. In addition to the reduction of the pilot to one year, with the opportunity for a second year, the Commission determines that additional changes to the JRR are necessary for proper measurement and verification. First, the Company shall require the Customer to maintain an employment level of 90 percent of the its employees, with the number of employees determined by an average of its employment level over the twelve months prior to the filing of the Application and Agreement for the Job Retention Rider. The application shall state the specific number of employees and verify that this number represents 90 percent of the monthly average over the past twelve months. Second, the Customer shall submit in writing to DEP no later than March 1, and quarterly thereafter, a report verifying the employment level at the Customer's facility(s) receiving the Job Retention Rider credits. Third, if the Customer does not maintain the stated employee level, the Customer shall be removed from the tariff pursuant to the language in the proposed application and shall be required to refund the amount of benefits received under the JRR. DEP shall change the application language accordingly. The Commission has considered the arguments for expanding the JRR made by DoD/FEA witness Mancinelli and Commercial Group witnesses Chriss and Rosa, and concludes that expanding the JRR to other customer classes would place too large a burden on non-participants and would be unreasonable.

Furthermore, the Commission concludes that limiting the availability of the JRR to only industrial customers is not unreasonably discriminatory. Rather, it is based on a reasonable difference between customer classes, and the discount offered to participants under the JRR as compared to the amount of rider recovery on non-participants bears a reasonable proportion to the difference between the customer classes. <u>See State ex rel. Utils. Comm'n v. Carolina Util.</u>

Customers Ass'n, 348 N.C. 452, 468, 500 S.E.2d 693, 704 (1998). Based on the evidence presented, the Commission finds that industrial customers' sales have been flat or declining since the recession, while residential and commercial sales are growing. Furthermore, a $0.00323 per kWh reduction in rates for participating industrials as compared to an increase in rates for the average retail customer of approximately $0.00051 per kWh per month under the JRR is proportionate to differences between these customer classes and reasonable given the economic and rate benefits of retaining industrial customers on DEP's system.

The Commission concludes that the JRR, with the modifications established in this Order, is in accordance with the requirements and guidelines the Commission previously established. In the JRT Order, the Commission directed utilities to "craft eligibility requirements that are narrowly tailored to meet the intended goals of maintaining jobs in the most economically efficient manner." Although the disputed phrase that allows for the eligibility for pipeline companies was included in the JRT Order as a possible example of eligibility criteria, the Commission is not persuaded that the eligibility criteria proposed by the Company is sufficiently narrow to ensure that the JRR will maintain jobs in the most efficient manner. Pipelines, which cannot relocate, are sufficiently different from other industrial customers and should be excluded from eligibility in the JRR. The disputed phrase "or the transportation or preservation of a raw material of a finished product" should be removed from the eligibility criteria. Further, due to the fact that DEP indicated that no pipeline customer is currently eligible for the JRR and that the Commission is limiting the JRR to one year with a possible extension of one year, it is unlikely that any pipeline customer would be affected by this decision.

The Commission further concludes that the customer attestations regarding certain eligibility requirements for the JRR, as modified by this order, are reasonable and adequate. Based upon the practical considerations of managing eligibility and how eligibility for certain rates is verified in other contexts, such as the opt-out process for DSM/EE rates, the Commission concludes that the Company's proposed method for verifying eligibility for the JRR is reasonable.

Commercial Group states that it does not take issue with the Commission's gradual approach to class revenue allocation, except if the Commission grants the proposed JRR. In that event, according to Commercial Group, the Commission should set LGS rates at cost in order to avoid a double subsidy by MGS customers. The Commission does not agree with Commercial Group's position. The approval of the JRR does not eviscerate the principle of gradualism in reaching rate of return equilibrium among the customer classes. Further, the rate designs approved herein and the approval of the JRR will result in just and reasonable rates.

Finally, the Commission notes the proposed JRR is a limited-term pilot, which will allow the Commission and the Company to follow the customers on the tariff and to consider whether the tariff meets its objectives of job retention and the related economic benefits. If it does not, then the JRR will not be continued beyond its one-year term. Except as modified by this order, the Commission finds that it is reasonable for DEP to implement JRR and JRRR as proposed in the Stipulation and Wheeler Settlement Exhibit 1.

The Company, as well as ratepayers, benefit from the retention of industrial jobs, and the load related to the retention of the industrial jobs. In addition to the testimony in this case, this fact is further justified by the Company's indication in Docket No. E-100, Sub 73 that it was considering funding all or a portion of a JRT and provided comments on the necessary requirements for measurement and verification under the scenario of a fully Company-funded JRT. To achieve just and reasonable rates, if the pilot program is extended to a second year, it is appropriate for the Company to contribute to the JRR at the same level as year one. Therefore, the Company's recovery should be reduced by the amount of $3.5 million if the Commission determines in the rider proceeding that the JRR pilot program should be extended to a second year.

The Commission, therefore, concludes that the proposed JRR, as modified by this Order, is in the public interest, is not discriminatory and is consistent with the Commission's holding that "approval of a JRT is a matter of sound ratemaking policy to address the undisputed decline in industrial sales in North Carolina." (See Order Adopting Guidelines for Job Retention Tariffs in Docket No. E-100, Sub 73, at 22.) If the JRR is extended an additional year and at the end of the second year the Company determines there is still a need for the JRR, nothing in this order prevents the Company for filing for a new JRR based upon the economic circumstances at that time.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 50-52

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

In Docket No. E-2, Sub 1103, DEP requested to defer its costs of complying with the Coal Ash Management Act (CAMA) and the EPA's Coal Combustion Residual Rule (CCR Rule, collectively CAMA), and notified the Commission that it had established an Asset Retirement Obligation (ARO) in the amount of approximately $2.5 billion to reflect its estimated costs of CAMA compliance.

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

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

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

> consideration for deferral. Second, the effect of not deferring the expenses on the Companies' respective earned returns on common equity would be significant.

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

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

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

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

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

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

> the Commission is of the opinion, and so concludes, that the Company should be, and hereby is, explicitly placed on notice that any proposed changes in the cost of removal for long-lived assets and/or in the accounting for such costs must be submitted to the Commission for its approval in the context of a general rate case or other appropriate proceeding prior to implementation.

2003 ARO Order, at 11-12.

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

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

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

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

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

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

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

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

The evidence supporting these findings of fact and conclusions is contained in the Application, Form E-1, the testimony of the public witnesses, and the testimony and exhibits of the following expert witnesses: DEP witnesses Fountain, Bateman, Kerin, Wells and Wright;

Public Staff witnesses Lucas, Garrett and Moore, Peedin and Maness; AGO witness Wittliff; CUCA witness O'Donnell; and Sierra Club witness Quarles.

The public witness testimony and expert witness testimony and exhibitsregarding DEP's coal combustion residuals (CCR) costs is voluminous. The Commission has carefully considered all of the evidence, and the record as a whole. However, the Commission has not attempted to recount every statement of every witnesses. Rather, the following is a complete summary of the evidence.

Likewise, the Commission has read and fully considered the parties' post-hearing briefs. However, the Commission has not in this Order expressly addressed every contention advanced or authority cited in the briefs.

Based upon the evidence addressed below and in the exercise of its expert judgment and discretion, the Commission determines that a management penalty of approximately $30 million should be assessed for DEP's mismanagement of its CCR activities undertaken through the end of the test year as extended for reasons set forth hereafter.

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

The United States Environmental Protection Agency (EPA) has studied CCRs and their proper management and handling since the 1980s and began moving forward on comprehensive regulation of CCRs approximately ten years ago. In 2010, the EPA issued proposed rules regarding CCRs. EPA's final rule – the Coal Combustion Residuals Rule (CCR Rule) – was promulgated on April 17, 2015. North Carolina also enacted specific statutory requirements for coal ash management in its Coal Ash Management Act (CAMA), which became effective in 2014 and was amended in 2016. The CCR Rule and CAMA introduced new requirements for the management of coal ash. DEP must comply with these new requirements, which mandate closure of the Company's coal ash basins. Mandated closure triggers Generally Accepted Accounting Principles (GAAP) provisions relating to the retirement of long- lived tangible assets, and specifically triggers the requirement that the Company account for compliance costs through Asset Retirement Obligation (ARO) accounting. The Company, as required by GAAP, established an ARO with respect to its coal ash basins, and, in accordance with the Commission's Orders in Docket No. E-2, Sub 826, deferred the impacts of its GAAP-mandated ARO accounting. The Company seeks recovery of the coal ash basin closure costs incurred to date in connection with CCR Rule and/or CAMA compliance, along with such costs it anticipates will be incurred annually on an ongoing basis. The Company's proposal has three component parts:

- First, DEP seeks recovery of the actual coal ash basin closure costs it incurred from January 1, 2015 through August 31, 2017. On a North Carolina retail jurisdiction basis, these costs (netted against the amount already included in the Company's rates following its last rate case) amount to $241.9 million.[1] The Company proposes further that, rather than recovering 100% of these already incurred costs immediately, it recover them over a five-year amortization period, and it seeks a return on the unamortized balance.

- Second, DEP seeks to recover on an ongoing basis $129.1 million per year in annual coal ash basin closure spend. This amount is based upon DEP's calculation of the NC retail jurisdiction portion of the test year (2016) coal ash basin closure expense incurred by the Company.

- Third, DEP seeks permission to establish a regulatory asset/liability and defer to this account the NC retail portion of annual costs that are over or under the costs established in connection with the Company's request that it be permitted to recover in rates on an ongoing basis its actual test year coal ash basin closure costs – i.e., the amount over or under $129.1 million, if the Company's proposal as detailed above is approved by the Commission. In addition, the costs incurred from September 1, 2017 through the date new rates set in this proceeding are effective would also be deferred to this account. The deferred amounts (including a return) would be brought into rates and recovered through future rate cases.

For cost recovery, a utility must show that the costs it seeks to recover are (1) "known and measurable"; (2) "reasonable and prudent"; and (3) "used and useful" in the provision of service to customers. Once shown, and, assuming no penalty for mismanagement, the utility is entitled to recover the costs so incurred.

The arguments raised by Intervenors in this docket challenge the inclusion of the Company's coal ash basin closure costs in rates because the costs are not "reasonable and prudent" and "used and useful," or on a theory that cost recovery should be shared by both the shareholders and ratepayers.

Summary of the Evidence

1. Company Direct Case Overview and Costs Sought for Recovery

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

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

that including this revenue requirement will provide a measure of predictability to customers of future coal ash expense rate drivers. (Id. at 41-42.)

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

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

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

2. Company Direct Case: Coal Ash Overview

Company witness Kerin provided a discussion of DEP's coal ash management history and practices and the new obligations imposed on the Company by the CCR Rule and CAMA. He explained that CCRs are by-products produced from the electricity production process lifecycle – the burning of coal – at coal-fired generation plants in coal-fired power generation plants and include fly ash, bottom ash, boiler slag, and flue gas desulfurization (FGD) material. He stated that environmental regulations related to CCR management have evolved over time, affecting how the Company has operated its coal-fired plants in compliance with those obligations. He described the steps in the environmental regulatory evolution process. He testified that, in his opinion, DEP was in line with industry standards and has reasonably and prudently managed CCRs and its coal ash basins. He explained that since its last rate case, DEP has become subject to both federal and state regulations that require it to take significant action to close its coal ash basins. (Tr. Vol. 16, pp. 103-05, 107-09.)

Witness Kerin testified that since the 1920s, DEP has disposed of CCRs in compliance with then current regulations and industry practices. Until the 1950s, CCRs were either emitted through, in the case of fly ash, smokestacks or, in the case of bottom ash, manually removed from boilers and stored in landfills. Since that time, the industry transitioned to a water sluice to remove coal ash from boilers, and to clean the electrostatic precipitators, preventing coal ash from being emitted through the smokestacks. This effluent, as well as FGD blowdown, was then diverted to coal ash basins, of which DEP has 19 in the Carolinas. In other words, in many cases, coal ash basins were actually created or relied upon to effectuate prior environmental regulations. In the mid-1970s, the enactment of the Clean Air Act and its subsequent amendment in the 1990s required electric utilities to capture more CCRs through the use of electrostatic precipitators (ESP) or bag houses and FGD blowdown. (Tr. Vol. 16, 108-09.)

Witness Kerin provided a detailed history of coal ash regulation. He testified that the Clean Water Act of 1972 and the subsequent creation of the National Pollutant Discharge Elimination System (NPDES) permitting system, made wet coal ash handling and coal ash basins the primary lawful and effective way to meet CCR needs and environmental requirements from 1974 until 2015.

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

Witness Kerin testified that in addition to the CCR Rule and CAMA, DEP is also subject to other CCR-related obligations that result from state environmental regulatory oversight under existing rules and regulations. For DEP, in South Carolina, there is one Consent Agreement with the South Carolina Department of Health and Environment (DHEC) applicable to ash management at the Robinson plant. The Robinson Consent Agreement, DHEC 15-23-HW, between Duke Energy Progress, Inc. (now Duke Energy Progress, LLC) and DHEC, requires coal ash excavation of a 1960 lay-of-land coal ash storage area located south of the coal ash basin. This Consent Agreement also includes provisions to initiate permitting of an on-site lined CCR landfill to store the excavated coal ash. (Tr. Vol. 16, p. 133.)

Witness Kerin noted that there is duplication and interaction between federal rule, state law and agency action and that many of the actions Duke Energy will take will serve multiple compliance purposes. He explained that actions and draft rules applicable to many utilities, not just Duke Energy, were being developed prior to 2014, and that the Company now confronts another wave in the evolution of environmental regulation pertaining to coal ash. He stated that in response to these new requirements addressing CCR disposal activities, the Company is adding dry fly ash, bottom ash, and FGD blowdown handling systems to operating coal-fired plants that are not already so equipped. He also stated that the Company is modifying all active and decommissioned plants to divert storm water and low-volume wastewater away from the basins. He testified that, accordingly, the Company is requesting recovery of the incremental compliance costs related to coal ash pond closures incurred starting in 2015 through August 31, 2017, and recovery of ongoing compliance costs. He testified that both these incurred and ongoing compliance costs are reasonable, prudent, and cost effective given the individual facts and circumstances at each power plant and coal ash basin site at issue. He testified further that each of the Company's historical and ongoing CCR compliance costs are reasonable, prudent, and cost effective given the individual facts and circumstances at each power plant and coal ash basin site at issue. (Id. at 106.)

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

Witness Kerin stated that coal ash removal has been initiated at several DEP stations, including the Asheville Plant, and the Sutton Plant. He stated that excavation plans were developed to systematically prepare for executing this work, including the identification of any necessary permits and approvals. These excavation plans were submitted to the applicable state regulatory body, DHEC or DEQ, prior to beginning coal ash excavations. As the CCR Rule and CAMA lead to coal ash basin closure, preparations are required to transition the coal-fired generating sites for this outcome. Operating coal-fired power plants in the Carolinas requires plant modifications to fully transition to dry ash handling in order to cease sluice flow to the coal ash basins. All coal-fired power plants, even those retired, require some level of modification to cease all flows to the basins, such as storm water or low volume waste water, and may require construction of a new retention pond. These modification activities are planned and are now being executed. (Id. at 136-37.)

Witness Kerin described the closure plans and site analysis and removal plans developed by DEP to physically close the coal ash basins, noting that these plans are technically informed by the structural stability of the impoundments, the potential for adverse impacts from external events such as 100-year floods, the groundwater and/or surface water impacts identified in the Comprehensive Site Assessments, and the groundwater corrective actions required in the Corrective Action Plans. Coal ash basins can be closed by excavation, with the coal ash permanently stored in a CCR landfill or used in a beneficial way such as a structural fill or for cementitious purposes. Coal ash basins can also be closed by capping the CCRs in place. (Id. at 137.)

Witness Kerin also stated that the Company's CAMA closure plans will meet the national standards set forth by the CCR Rule as well as the more specific requirements determined by DEQ under the CAMA regulatory process. He explained that the state- mandated closure plans are reviewed and approved by DHEC in South Carolina and DEQ in North Carolina. During this review and approval process, these state regulatory agencies could impose additional restrictions, limitations, requirements, and/or actions to close the coal ash basins. Other specific compliance plans will be developed and implemented to meet the various requirements and timelines of CAMA and the CCR Rule, such as the fugitive dust control plans which were required under Section 257.80 of the CCR Rule by October 19, 2015. As a second example, run-on and run-off control system plans were developed and implemented by October 19, 2016, for CCR landfills pursuant to Section 257.81 of the CCR Rule. Compliance plans will continue to be developed and implemented as required by the CCR Rule and CAMA. (Id. at 137-38.)

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

Company witness Kerin explained that, in his opinion, DEP's historical handling of CCRs was reasonable, prudent, and consistent with industry standards over time. He stated that, in his opinion, this demonstrates that nothing that DEP has done historically is causing the Company to incur any unjustified costs today to comply with post-2015 CCR regulations. (Id. at 143.) Company witness Kerin explained that, in the preamble to the CCR Rule, EPA details that in 2012 alone, over 470 coal- fired electric generating facilities burned over 800 million tons of coal, generating approximately 110 million tons of CCRs in 47 states and Puerto Rico. In 2012, approximately 40% of the CCRs generated were beneficially used, with the remaining 60% disposed in CCR surface impoundments; of that 60 percent, approximately 80% was stored in on-site basins and landfills. Across the United States, CCR disposal currently occurs at over 310 active on-site landfills, averaging over 120 acres in size with an average depth of 40 feet, and at over 375 active on-site surface impoundments. Witness Kerin testified that the Company is re-using (selling) and storing CCRs in the same manner and at approximately the same percentages as the coal-fired utility industry's national averages.

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

Witness Kerin also maintained that DEP'S CCR storage and handling practices are consistent with the practices of other Duke Energy affiliates and Duke Energy peer utilities. He explained that the Company's CCR storage and handling practices are consistent across the Duke Energy fleet, including coal generation located in Florida and in the Midwest. Duke Energy, as it currently exists today, has been formed over the years through the mergers of several utilities with independently operated coal fired generation. He testified that the historical and current CCR handling and use of CCR basins is consistent across these legacy companies that make up Duke Energy Corporation today, and consistent with the industry. (Tr. Vol. 16, p. 119.)

Company witness Wright noted that coal ash use and disposal have been studied by the EPA since the mid-1980s. After several studies and some limited regulatory standards, on May 22, 2000, the EPA determined the need to regulate coal combustion wastes under Subtitle D of the Resource Conservation and Recovery Act (RCRA). He noted that these types of expenses have been routinely recovered as a cost of service and included in rate cases, including the reasonable costs associated with operating, maintaining and upgrading environmental equipment. The cost recovery for these rate-based environmental costs also usually included a return. (Tr. Vol. 13, 361-62.)

3. Company Direct: Cost Recovery Overview

Witness Wright also testified that, in part, as a response to an accident at a surface impoundment at Tennessee Valley Authority's ("TVA") Kingston Fossil Plant in Harriman, Tennessee, the EPA published in the Federal Register proposed new coal ash disposal regulations for CCRs. The proposed regulations specifically referenced the TVA incident as a major reason for the proposed rule, and EPA discussed several other coal ash incidents that led to the promulgation of the rule. Witness Wright noted that, because the EPA's proposed rule's publication date precedes the February 2, 2014 coal ash release accident at the Dan River Steam Station ("Dan River"), the Dan River accident was not mentioned in the EPA's proposed rule as a reason for establishing the rule. He also noted that EPA's finalized CCR Rule, signed on December 19, 2014, and published in the Federal Register (FR) on April 17, 2015, referenced the Dan River accident, without indicating that the accident modified the proposed rule. (Tr. Vol. 13, pp. 362-63.)

He further explained that in August 2014, after the EPA's proposed coal ash regulations were published but prior to their finalization, the State of North Carolina adopted CAMA. He noted that while the EPA's and the CAMA rules are "largely duplicative," the Company must ensure that its coal ash disposal methods meet the standards established in both regulations as well as any other state agency requirements. (Tr. Vol. 13, pp. 363-64.)

Witness Wright testified that, in his opinion, recoverable costs, as they relate to electric utility expenditures in North Carolina, are costs that are reasonable and that are prudently incurred in the provision of safe, reliable electric service to a utility's customers. He stated that G.S. 62-133(b) embodies this principle. He stated that because environmental compliance costs are a necessary cost of providing electric service, these types of costs – and a return on those costs if deferred over time – are recoverable in rates. He also stated that environmental compliance costs are similar to other costs that a utility might spend in producing and delivering power. He explained that the Company incurs costs in compliance with environmental laws and regulations, similar to other costs necessary for the generation of electric power, and that these coal ash disposal costs are like nuclear decommissioning costs or coal plant retirement costs that have long been deemed recoverable for utilities across the country, including DEP. (Id. at 354.)

Witness Wright noted that the Commission has allowed the recovery of costs related to environmental expenditures. Citing to witness Kerin's lengthy discussion of the numerous investments the Company has made over time in compliance with historical coal ash and other environmental regulations, he stated that in his experience these types of costs, including the reasonable costs associated with operating, maintaining and upgrading environmental equipment, plus a return, have been routinely recovered as a cost of service through general rate cases, whether as capital or ongoing operation and maintenance expense or some combination thereof. (Id. at 358- 60.)

Witness Wright testified further that utilities are not allowed to recover environmental fines or penalties, or costs incurred from the actions causing such penalties. He stated his understanding that none have been requested in this case. However, according to witness Wright, it is important to make sure that the costs underlying or directly causing such fines or penalties be separated from prudently incurred, ongoing costs. For example, if a generating plant received a fine, then by no means should that fine be recoverable. But the fact that a fine was given does not mean that the ongoing, prudently- incurred costs necessary to produce generation should be disallowed. (Id. at 361.)

He further explained why, in his view, the new federal coal ash standards did not result from the Dan River spill. He noted that the final rule only mentions the Dan River accident, and that there is no evidence in the final rule that the Dan River accident changed or modified the EPA's proposed rule. He testified that both the proposed rule and the final rule addressed the need for imposing corrective action at inactive facilities, and stated that in promulgating the CCR Rule, the EPA cited hundreds of potential risks or incidents with ash ponds similar to Dan River that, in part, led to the adoption of the Rule. Based on this analysis along with the timing of the CCR Rule, he opined that the Dan River accident did not change the CCR regulations, although it probably added support for the EPA's proposals. (Id. at 363-65.)

Witness Wright also testified that, in terms of timing, the new state CAMA coal ash standards did result from the Dan River spill, but, in his view, in terms of the substance of the standards adopted, there is not necessarily a connection. He opined that the Dan River spill helped prompt the North Carolina General Assembly to examine the North Carolina and national coal ash disposal policies and regulations, and that out of that legislative investigation came CAMA. He noted that some four years prior to Dan River, the EPA had proposed and was close to finalizing its new CCR regulations, which, in his opinion, helped inform the state's legislative leaders regarding the language contained in CAMA. He noted that the proposed CCR regulation also strongly encouraged the states to adopt at least the federal minimum criteria in their solid waste management plans. Therefore, he concluded, the North Carolina Legislature and/or the State's DEQ would likely have taken steps to adopt some coal ash regulations shortly after the CCR Rule was finalized in 2015 simply because of the CCR Rule's encouragement to do so. He concluded that the timing of CAMA was certainly influenced by the Dan River accident, but also stated his belief that, even without the Dan River accident, the state would likely have adopted some new coal ash disposal standards in the 2015 timeframe simply in response to the CCR rules, as it did just a few years prior to adopting CAMA, when it adopted coal-fired generating facility environmental standards in the Clean Smokestacks Act that were stricter than the federal standards at the time. He stated that, regardless, the Company must comply with both the federal and state coal ash disposal standards. (Id. at 366-67.)

In his direct testimony, Company witness Wright testified that in his opinion the coal ash disposal costs that DEP seeks to recover in this case are "used and useful" utility cost. (Tr. Vol. 13,

p. 375.) He explained that DEP's coal ash disposal sites have always been used and useful as part of the coal-fired generation production process. He noted that G.S. 62-133(b)(1) provides that, in setting utility rates, the Commission must "ascertain the reasonable original cost of the public utility's property used and useful, or to be used and useful within a reasonable time after the test period, in providing the service rendered to the public within the state, minus accumulated depreciation, and plus the reasonable cost of the investment in construction work in progress." (Id.) He testified that, therefore, to be included in rate base, the cost must be both reasonable and incurred for property that is used and useful in providing service to customers. He stated that the Company has historically spent dollars in order to comply with the coal ash disposal regulations in effect at the time, and these dollars were a necessary expenditure related to used and useful utility costs made in the provision of electric service at the time. (Id. at 375-76.) The Company was, and continues to be, in his view, obligated to meet the needs of its customers. This obligation to serve requires the disposal of coal ash subject to the disposal standards at the time, thereby rendering the disposal sites for this coal ash, for which costs DEP seeks recovery in this case, "used and useful" in providing electric service. (Id. at 376.) He stated that this conclusion is supported by the Commission's conclusions in the 2016 Dominion rate case, where the Commission determined that because current CCR repositories are and have served their purpose of storing CCRs for many years, they have been used and useful for ratepayers, and that such storage facilities will continue to be used and useful until the CCRs are moved to a permanent repository, or they are capped and closed. (Id. at 376-78.)

Company witness Wright also noted that the Commission addressed this exact coal ash disposal cost issue in its December 22, 2016 Order in Dominion's recent rate case, Docket No. E-22, Sub 532. He noted that in that order the Commission and Public Staff concluded that Dominion's historical response to coal ash disposal was consistent with industry practice at the time and that these costs were reasonable and prudent. Second, they found that Dominion's test year coal ash disposal expenses incurred in compliance with the newer coal ash disposal regulations were likewise reasonable and prudent. A third important point decided by the Commission in the Dominion case, he maintained, was that the prior coal ash disposal assets were used and useful. Finally, similar to what DEP is requesting in this rate case, the Dominion order also allows Dominion to establish an ARO to defer additional coal ash disposal cost and for the recovery of those costs to be adjudicated in a future proceeding. (Id. at 378-79.)

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

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

CUCA witness O'Donnell purported to compare the DEP coal ash ARO to what he termed similar coal ash AROs of utilities across the United States. He concluded that the Company's ARO coal ash costs are the highest in the nation, and contended that the only discernable difference between DEP and the other utilities in his comparison was CAMA, which he asserted was prompted by the Dan River spill. He stated that DEP did not provide a similar financial analysis for this case. (Tr. Vol. 15, pp. 230-31.) Witness O'Donnell opined that DEP should only recover costs to comply with the CCR Rule, not any costs under CAMA that exceed CCR Rule compliance costs, based on his contention that Duke Energy caused CAMA. (Tr. Vol. 16, p. 18.)

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

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

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

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

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

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

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

The AGO contends that DEP is not entitled to special cost recovery. DEP was recovering these costs in depreciation expense through amortization for retired plants. The AGO cites to the Burns & McDonnell 2012 dismantlement studies indicating lower estimated closure costs, based upon dewatering and capping in place. The AGO states that now that recovery for closure costs is much greater, DEP seeks a special accounting method. The AGO argues that imposing these coal ash costs on current ratepayers raises intergenerational fairness given DEP's failure to take action earlier. The AGO highlights that the Commission has previously dealt with the intergenerational issue when it considered whether to allow the recovery of manufactured gas plant clean-up costs based upon new environmental requirements. The AGO states that the Commission allowed recovery of the clean-up costs; however, the amount was amortized over a period of years, and no carrying costs were allowed on the unamortized balance.

In addition, the AGO submits that DEP should not receive "carrying costs" during amortization of the deferred CCR costs by placing the unamortized balance in rate base because the deferred CCR costs are special operating expenses. According to the AGO, operating expenses are recoverable without return pursuant to G.S. 62-133(b)(3) and State ex rel. Utilities Commission v. Thornburg (Thornburg I), 325 N.C. 463, 475, 385 S.E.2d 451, 458. Further, the AGO submits that the unamortized balance of the CCR deferred costs are similar to those considered in State ex rel. Utilities Comm. v. Carolina Water, 335 N.C. 493, 507, 439 S.E.2d 127, 135 (1994) (Carolina Water), where the Supreme Court considered whether the Commission erred when it treated utility plant that was not in service at the end of the test year – and would not be returned to service – as "an extraordinary property retirement," allowed amortization of the unrecoverable costs over ten years, and included the unamortized portion in rate base. The Court concluded that the costs were for plant that was not used or useful and, thus, the unamortized costs should not have been included in rate base. As the Supreme Court explained: "Including [these] costs in rate base allows the company to earn a return on its investment at the expense of the ratepayers." Id. at 508, 439 S.E.2d at 135 (citations omitted).

Finally, the AGO notes that a similar issue was considered by the Commission in the 2016 DNCP general rate case relating to rate base treatment of the unamortized balance during CCR cost recovery, wherein the Commission distinguished the circumstances in Carolina Water. The AGO contends that the Commission's decision in the DNCP case should not set the standard for the present case because the determination was allowed under the circumstances presented in that case without precedential effect regarding the treatment of CCR costs in future proceedings.

In its post-hearing Brief, CUCA contends that DEP's request for 100% CAMA compliance cost recovery is not appropriate. CUCA submits that DEP's costs are overstated and that many are the result of DEP's negligence, which is most clearly highlighted in DEP's guilty plea in the federal criminal environmental proceeding. CUCA supports an equitable sharing of the CCR cleanup costs due to the fact that CAMA costs are much higher than the CCR Rule compliance costs. CUCA states that a 25% recovery is equitable. CUCA argues that this case is different than the DNCP rate case. DEP is different than Dominion in the used and useful analysis in that Dominion never had a coal ash spill, did not plead guilty to Clean Water Act violations, did not pay $102 million for mismanagement, and did not admit that CAMA was passed due to the Dan River spill. Further, CUCA contends that the CCR Rule is a self-implementing rule which has not been triggered by any citizen suits, and that in the absence of a regulatory directive to do so, DEP should not have pursued regulatory closure of operating sites.

Sierra Club, in its post-hearing Brief, argues that closure of DEP's coal ash ponds is necessary to address unlawful discharges to surface waters and therefore closure costs are not recoverable, citing G.S. 62-133.13. Further, Sierra Club contends that all of the CCR basins are unlawfully discharging pollutants into surface waters and the only way to stop these unlawful discharges is to close the pond and eliminate the source, the coal ash. Therefore, the costs of pond closure results from the unlawful discharges and are not recoverable.

In addition, Sierra Club submits that DEP has failed to meet its burden of demonstrating that its proposed rates are just and reasonable in that no evidence exists to prove that storage of coal ash in unlined, leaking ponds for decades was a reasonable and prudent way for DEP to manage its CCRs. According to Sierra Club, the only evidence provided was Kerin's bold assertion that historical handling of CCRs was reasonable, prudent and consistent with industry standards over time. Sierra Club cites to the Commission's ratemaking decision regarding MGP clean-up asserting that when determining ratepayer responsibility, the prudency of the Company's initial operation of each site should be considered. In that case, the Commission found prudent operation. In contrast, the Sierra Club states that the record shows a history of mismanagement with respect to coal ash basins, citing seeps at almost all of its ash ponds as being unlawful discharges that violate the federal Clean Water Act and Section 143-215.1 of the North Carolina General Statutes, and the terms of DEP's NPDES permits. Sierra Club maintains that the operation of a system meant to treat wastewater in a manner that allows the release of untreated wastewater and repeated violations of the law cannot be considered prudent, and that DEP provided no evidence on whether its prior CCR management practices have resulted in unjustified costs.

Moreover, Sierra Club argues that DEP's closure plans for its Mayo and Roxboro ash basins do not comply with the CCR Rule or protect against continued discharges, and, therefore, DEP's proposed run rate should be rejected.

Sierra Club also contends that capping in place the Mayo and Roxboro CCR basins will not protect against continued leaching of coal ash constituents into groundwater or into surface waters through migration. Therefore, it submits that DEP's closure plans violate the CCR Rule. Sierra Club notes that there are two federal lawsuits pending on this issue, and that a closure plan that does not protect against future contamination cannot be considered prudent. DEP's run rate is based upon the assumption that ash ponds at Mayo and Roxboro will be capped in place. Therefore it is not reasonable to approve an ongoing run rate for future cleanup when the full scope of those costs is not understood. Therefore, according to Sierra Club DEP's request for a run rate based upon the assumption that the ash ponds at Mayo and Roxboro will be capped in place should be rejected.

In its post-hearing Brief, NC WARN contends that DEP should be severely limited on coal ash cost recovery. NC WARN asserts that none of the costs associated with coal ash mitigation and cleanup should be borne by ratepayers, and that DEP should not make profits on selling coal ash from its existing coal ash basins as part of a permanent disposal scheme.

In its post-hearing Brief, Fayetteville PWC suggests that the Commission impose a provisional deferral of costs in an amount equal to DEP's insurance coverage for such remediation liabilities, which costs may not be recovered from ratepayers unless or until DEP either recovers offsetting insurance proceeds or demonstrates that DEP's own actions or omissions did not result in a denial of insurance coverage or a reduced settlement for its coal ash remediation costs. Fayetteville PWC also requests that the Commission adopt the coal ash remediation costs disallowances and deferral recommended by the Public Staff and order the sharing of coal ash remediation costs between DEP's shareholders and ratepayers in the manner recommended by Public Staff.

In its post-hearing Brief, CIGFUR argues that DEP should not be allowed an equity component in the calculation of its deferred coal ash remediation carrying costs and that the appropriate amortization period is ten to fifteen years as opposed to five. CIGFUR states that the total cost to defer is $260.3 million and that the carrying charges associated with the incurred coal ash costs since 2015 are $9.4 million, $1.9 million is associated with the cost of debt and $7.5 million is associated with the cost of equity. CIGFUR further states that amortizing over 5 years results in annual amortization expense of $52.1 million, plus a $14.4 million net tax return, for a total requested revenue requirement of $66.5 million for deferred coal ash pond closure costs. CIGFUR argues that the carrying costs should not include the equity component and that the deferral should be financed at the lowest option, which is the cost of debt. Allowing the equity component increases the amount charged to DEP's ratepayers and is inappropriate for such a significant expense that fails to enhance reliable service. CIGFUR submits that the CCR costs were incurred over many decades and the stored coal ash is no longer used and useful in the provision of electric service.

With respect to the run rate, CIGFUR argues that DEP should not recover the run rate of $129.1 million and that DEP should defer ongoing costs for future recovery in its next rate case. CIGFUR opposes any carrying costs on the deferred amounts because the deferred amounts are not capital costs and that it is more appropriate to allow a $1 for $1 recovery and no more.

In its post-hearing Brief, Quad Towns states that the Commission must determine whether the initial operation of each site was prudent, as discussed in the Commission's MGP case. Quad Towns contends that most intervenors argued that DEP's demonstrated and criminally negligent failure to prudently and reasonably manage its CCR impoundments was the driving force for the enactment of CAMA, which increased the costs. Thus, these costs were not prudently incurred because if DEP had prudently managed its sites, these costs would have been avoided.

Further, Quad Towns notes that DEP argues that additional safeguarding in the past would have been deemed gold-plating and any such costs would have been deemed imprudently incurred. According to Quad Towns, given the fact that DEP had 485 NPDES permit violations, over 200 documented seeps and 2,857 2L violations, it is hard to assume that additional safeguards would have been gold-plating.

In addition, Quad Towns argues that costs arising out of mismanagement of a long- lived asset are not appropriate for deferral accounting, and notes that Section A13 of FASB states that obligations resulting from improper operations do not represent costs that are an integral part of the asset. The section goes on to state some spillage is acceptable, but the obligation to clean up after a catastrophic accident does not result from the normal operation of the facility. Because such costs are not appropriate for deferral, the costs should be borne by shareholders. Quad Towns states that it interprets the section language broader than the given example of a catastrophic accident.

Quad Towns also argues that the Commission cannot police the utilities' day to day operations to ensure that it is prudently managing its facilities in a safe and environmentally appropriate manner, and that the only way that the Commission can protect ratepayers from exorbitant rate increases due to mismanagement of utility operations is to disallow those costs that are attributable to the mismanagement.

Quad Towns supports a 75% disallowance of the historic costs based upon CUCA witness O'Donnell's testimony, and the same result but different analysis of AGO witness Witliff. It notes that witness Witliff testified that specifically looking at the Sutton and Asheville sites designated as high priority by CAMA, DEP spent approximately 72% more due solely to the accelerated timeline and DEP choosing to move the coal ash offsite. As further support, DEP's 2012 dismantlement study, after the 2010 CCR Rule was proposed, concluded that a $10 million depreciation expense would suffice to address end-of-life costs. Therefore, costs above $10 million earmarked in 2012 are attributable to the more costly CAMA closure requirements. Further, Quad Towns supports the specific Garrett and Moore disallowances.

For future costs, Quad Towns supports the Public Staff's 50/50 sharing proposal, and states that cost sharing is appropriate because: (1) DEP failed to prevent environmental contamination from its impoundments in violation of state and federal law, and (2) there is a history of approval for sharing extremely large costs that do not result in new generation of electricity for customers, such as the MGP case.

Moreover, Quad Towns argues that DEP saying its actions were in accordance with industry practice is incompatible with DEP's admissions in federal court to criminal actions that DEP "failed to exercise the degree of care that someone with ordinary prudence would have exercised in the same circumstance with respect to..." management of various aspects of its coal ash impoundments, and acted negligently in failing to prevent unauthorized discharges and to follow the conditions of its permits.

Further, Quad Towns argues that the Commission should disallow any recovery of CCR costs through the fuel adjustment clause, based on the fact that no cost was assigned to coal ash in the Charah contract with DEP. Rather the contract supports payment for coal ash remediation. Further, according to Quad Towns the evidence tends to show that Charah purchased the Brickhaven mine for the singular purpose of disposing of CCRs. Therefore, there was not an independent need for fill dirt.

Lastly, Quad Towns requests that the Commission specify the amount of disallowance. For example, if the Commission chooses to disallow a certain amount of CCR costs through amortization, if the Commission can clearly specify the amount of disallowance first and then explain that the disallowance is being achieved by the extended amortization, it will assist in avoiding future litigation over language in Quad Towns' wholesale purchase power agreements. Quad Towns states that if the Commission disallows 50% of DEP's request, Quad Town's customers will save approximately $309,902.50.

5. The Position of Public Staff Witnesses Garrett and Moore

Public Staff witnesses Garrett and Moore testified that they investigated the prudence and reasonableness of costs incurred by DEP with respect to its coal ash management. In addition, they reviewed the approach taken by DEP to determine the least cost method of achieving compliance with the laws and regulations governing coal ash management. In conducting their investigation, witnesses Garrett and Moore reviewed the closure plans and coal ash-related costs incurred for all of DEP's coal-fired facilities, conducted extensive discovery, participated in numerous meetings, and visited several of the DEP facilities in question. (Tr. Vol. 18, pp. 133-34.)

Witnesses Garrett and Moore did not take exception with DEP witness Kerin's general characterization of the applicable federal and state regulations addressing the management and closure of coal ash basins in North Carolina and South Carolina. They did, however, identify several decisions made by DEP that were not required by law or where lower-cost compliance options were available. Witnesses Garrett and Moore did not take exception with DEP's selected closure method for the coal ash basins at the Robinson Plant in South Carolina, which is subject to a consent agreement entered into between DEP and the South Carolina Department of Health and Environmental Control (DHEC). (Tr. Vol. 18, p 139.)

With regard to DEP's Mayo and Roxboro plants, witnesses Garrett and Moore noted that DEQ issued final classifications for these facilities as Intermediate Risk in May 2016, and that DEP is in the process of establishing the permanent replacement water supplies required under G.S. 130A-309.211(c)(1) and performing the applicable dam safety repair work at these sites. Upon completion of these tasks within the timeframe provided, the impoundments at these facilities will be reclassified as low-risk pursuant to G.S. 130A-309.213(d)(1). They explained that CAMA requires, at a minimum, that the impoundment be dewatered and closed either by excavation or by placement of a cap system that is designed to minimize infiltration and erosion. Witnesses Garrett and Moore noted that this approach is generally the most cost- effective means for closure of a CCR unit. They also testified that CAMA (S.L. 2016-95) does not require the submission of proposed closure plans for low- and intermediate risk impoundments until December 31, 2019, so DEP has not submitted a Site Analysis and Removal Plan (SARP) to DEQ for any facilities other than Sutton and Asheville at this time. Therefore, a prudence review of the Mayo and Roxboro closure plans would be premature, so witnesses Garrett and Moore took no exception in the present case to DEP's current proposed closure method for the coal ash basins located at Mayo and Roxboro. (Tr. Vol. 18, pp. 139-41.)

In addition, Public Staff witnesses Garrett and Moore did not take exception to DEP's closure method for the CCR units located at Cape Fear and H. F. Lee. DEP has selected the Cape Fear and H. F. Lee Stations as two of the three beneficiation sites pursuant to G.S. 130A-309.216, which required Duke Energy to identify three sites located within the state with coal ash stored in the impoundments suitable for processing for cementitious purposes. Upon selection of the sites, Duke Energy was required to enter into a binding agreement for the installation and operation of coal ash beneficiation projects at each site capable of annually processing 300,000 tons of coal ash to specifications appropriate for cementitious products, with all processed coal ash to be removed from the impoundments located at the sites. (Tr. Vol. 18, pp. 141-43) Witnesses Garrett and Moore also noted that the timeframe proposed by DEP for beneficiation of the Intermediate Risk sites extends beyond the closure timeframe called for in Section 3.(a) of S.L. 2016- 95 for sites deemed Intermediate Risk, and that G.S. 130A-309.215 provides a variance option for closure deadlines that are found to be in the public interest. (Id.)

Public Staff witnesses Garrett and Moore testified that they did not take exception to DEP's closure method for the CCR units located at Weatherspoon, where DEP has selected the excavation of CCR and beneficial use option, with contracts in place for the delivery of the coal ash material to facilities in South Carolina for use in the concrete industry. They noted that this option appears to offer a lower cost than other closure options for the site, and believe that DEP should have sought to establish Weatherspoon as one of the three beneficiation sites as required by G.S. 130A-309.216. This would have allowed the DEC Buck Station, which was instead selected as the third beneficiation site, to utilize significantly lower cost closure options instead of cementitious beneficiation. Witnesses Garrett and Moore testified that DEP indicated in response to data requests that it could only obtain guaranteed commitments for 230,000 tons of coal ash per year, as opposed to the 300,000 required by statute. They indicated that the potential cost savings associated with selecting Buck for closure options other than beneficiation would have justified making additional efforts to identify additional sites for beneficial reuse of coal ash of the additional 70,000 tonsof coal ash from Weatherspoon. (Tr. Vol. 18, pp. 143-44.)

With regard to DEP's selected closure actions at the Sutton Plant, witnesses Garrett and Moore took exception with DEP's decision to excavate and transport coal ash off-site to the Brickhaven structural fill facility in Chatham County. They contended that had DEP expeditiously pursued an on-site industrial landfill at the time it began working on the structural fill facility, it could have disposed of all of the coal ash on-site without incurring the added expense associated with the off-site transfer and disposal. (Tr. Vol. 18, pp. 153-55.)

Witnesses Garrett and Moore disputed DEP's position that the moratorium on CCR landfills, which was enacted on September 20, 2014, in Section 5.(a) of S.L. 2014- 122, and expired on August 1, 2015, had any impact on DEP's ability to construct an on-site greenfield landfill at Sutton in a timely fashion. They evaluated the timeframe for which DEP would have had to construct the landfill and determined that based on DEP's assumptions regarding landfill permitting and construction timeframes, along with the excavation and placement rates estimated by DEP in its analysis of the facility, DEP could have handled all of the coal ash on-site without having to incur the significant costs associated with off-site transportation costs and construction of rail handling equipment. (Tr. Vol. 18, pp. 145-48.)

Witnesses Garrett and Moore also took exception with DEP's inclusion of costs associated with two specific liner components, called the "Secondary Geocomposite Layer" and "Secondary 60-mil HDPE 9 Textured Geomembrane Material" that were included in DEP's current on-site landfill construction contract. They testified that these secondary layers exceed what is required under federal and state regulations. Therefore, witnesses Garrett and Moore recommended that the costs associated with these secondary liner layers be disallowed. (Tr. Vol. 18, p. 154.)

As a result of DEP's unnecessary actions to transport coal ash off-site from the Sutton facility and to install landfill liner components that exceeded regulatory requirements, witnesses Garrett and Moore recommended a total disallowance at the Sutton facility of $80.5 million from DEP's coal ash expenditures during this recovery period. (Public Staff Garrett and Moore Exhibit 7)

Witnesses Garrett and Moore summarized the coal ash closure approach taken by DEP at its Asheville facility. They testified that DEP had been excavating coal ash from the 1982 Ash Basin since 2007 in order to provide structural fill material for the Asheville Regional Airport, transporting this material by truck. Following passage of CAMA in 2014, which deemed Asheville a High-Priority site subject to an August 2019 closure date, DEP continued to excavate coal ash and transport it off-site while the potential for an on-site landfill was evaluated. However, passage of the Mountain Energy Act of 2015 (S.L. 2015-110, hereinafter the "MEA") amended the required completion date for closing the two coal ash basins to August 1, 2022, to allow time for the construction of a combined cycle plant on the site, and retirement of the existing coal-fired generating station. (Tr. Vol. 18, pp. 155-56.)

In their direct testimony, witnesses Garrett and Moore took exception with DEP's decision not to pursue an on-site industrial landfill at the Asheville site, on the basis that DEP could have avoided incurring significant off-site transportation costs. Witnesses Garrett and Moore noted that while the design and construction of an on-site industrial landfill at the Asheville facility would have been technically challenging, they believed that it could be done at a lower cost than transporting the remaining coal ash materials off- site. Witnesses Garrett and Moore also testified that the coal ash processing costs expended at the Asheville facility relative to the amount of coal ash that had been removed off-site were unreasonable. (Tr. Vol. 18, pp. 156-60.)

Following the filing of rebuttal testimony by DEP witness Kerin and updated discovery responses from DEP, witnesses Garrett and Moore revised their testimony to indicate that while they no longer took exception with the quantities of coal ash that had been removed from the 1982 Basin at Asheville to accommodate construction of the combined cycle facility, they took exception to (a) the schedule on which DEP removed the coal ash, which resulted in the unnecessary double-handling of some coal ash on site; (b) DEP's decision to transport excavated coal ash to the Waste Management landfill in Homer, Georgia, rather than transporting all of the excavated coal ash to a DEP- or DEC-owned facility, such as the DEC-owned Cliffside landfill; and (c) the per- ton/mile rates paid by DEP to Charah to transport the material from the Asheville site to Cliffside. Witnesses Garrett and Moore instead contended that a reasonable calculation for coal ash transporting costs should be based on the per-ton/mile rates calculated from the Waste Management Contract, but utilizing the shorter transporting distance and lower tipping or placement fee associated with the Cliffside landfill. In total, their proposed disallowance related to the Asheville facility totaled $29.3 million. (Tr. Vol. 18, pp. 173-76.)

Public Staff witnesses Lucas, Garrett, and Moore recommended disallowances of particular coal ash costs. In addition, witnesses Lucas and Maness proposed an "equitable sharing" of the remaining coal ash costs.

6. Public Staff Witnesses Lucas' and Maness' Equitable Sharing And Coal Ash Adjustments Testimony

Witness Lucas listed three conceptual options for regulatory treatment of coal ash costs. The first option is to allow full recovery of coal-ash related costs on the grounds that the costs have been reasonably incurred to comply with CAMA and the CCR Rule. This is essentially the approach recommended by DEP, minus costs listed in its federal criminal plea agreement as being non-recoverable in rate proceedings. The second option is to disallow recovery of costs to comply with CAMA on the grounds that CAMA is the direct consequence of imprudent Duke Energy environmental violations. This is essentially the approach recommended by CUCA and the Attorney General witnesses. The third option is to disallow the costs incurred to defend and remedy environmental violations, except to the extent that CAMA requirements increased the cost of remediation. Under this approach, which the Public Staff advocates, disallowances would be based on the costs to remediate environmental violations rather than the costs flowing from CAMA compliance. (Tr. Vol. 18, pp. 270- 71)

However, witness Lucas encountered "complicating factors" that led him to modify his preferred regulatory treatment. (Tr. Vol. 18, pp. 271-73) He observed that while some environmental violations are clearly due to Company negligence, others fall into a gray zone where they are neither plainly imprudent nor plainly reasonable. For instance, decisions to place coal ash in unlined impoundments could have been reasonable based on what DEP knew or should have known at the time the basins were constructed some decades in the past. At the same time, it can be unreasonable to impose on ratepayers the costs incurred because those impoundments leaked coal ash constituents and contaminated groundwater outside the compliance boundaries, in violation of state environmental laws and regulations. He also stated that the costs of many environmental violations would be too speculative to determine, as they involve estimations based on scenarios that did not occur (preventing violations through basin construction or modification some decades earlier, or remedying violations if there had been no CAMA).

Due to the complicating factors, witness Lucas offered what he classified as a more practical approach, proposing to exclude the following coal ash costs from recovery in rates:

(1) DEP litigation costs and settlement payments in cases where there are environmental violations;
(2) costs to remedy environmental violations where the costs exceed what CAMA would have required in the absence of environmental violations;
(3) costs required to be excluded under the probation conditions of the federal plea agreement;
(4) the recommended disallowances from Garrett and Moore to the extent there is no double disallowance for the same item; and

(5) an equitable sharing of the remaining allowed costs of coal ash management through the deferral and amortization approach recommended by Public Staff witness Maness.

(Tr. Vol. 18, pp. 274-75.)

According to witness Lucas, DEP had stated that it had excluded all costs required to be excluded under the probation conditions of the federal plea agreement. (Tr. Vol. 18, p. 281) Thus, the regulatory treatment of those costs is not in dispute. The remaining areas listed by witness Lucas include litigation and settlement payments in cases of environmental violations. In this category, he recommended exclusion of $88,000 (total system, not just NC retail as shown in Peedin Exhibit 1, Schedule 3-1(n), line 1, $53,328-North Carolina retail) of test year outside legal fees for litigation of a penalty assessment brought by the North Carolina DEQ and a Clean Water Act lawsuit brought by citizen clients (environmental organizations) of SELC, both in connection with coal ash contamination from DEP's Sutton plant. (Tr. Vol. 18, p. 277)

For the category of costs to remedy environmental violations where the costs exceed what CAMA would have required in the absence of environmental violations, witness Lucas identified, to date, $6,693,390 (NC retail) incurred from January 1, 2015, to August 31, 2017, for extraction wells and treatment of groundwater pursuant to the settlement agreement between DEQ and DEP in the Sutton penalty assessment case. He took the position that these costs would not have been incurred but for unlawful contamination of groundwater by DEP coal ash basins, and that these costs are over and above the lowest reasonable costs of CAMA compliance in the absence of violations. He noted that there could be additional costs in this category in the future. (Tr. Vol. 18, pp. 278-80)

The final category for disallowance is based on an "equitable sharing" of all coal ash-related costs not otherwise disallowed. Witness Lucas referred to witness Maness' testimony for a description of how the equitable sharing should be implemented and the reasons for it. Witness Lucas further opined that "[a]n equitable sharing is particularly appropriate in light of the extent of the Company's failure to prevent environmental contamination from its coal ash impoundments, in violation of state and federal laws." In this regard, he noted the nature and extent of coal ash environmental problems addressed in the federal criminal plea agreement, violations of NPDES permits, dam safety deficiencies, and numerous groundwater exceedances. He added that the sheer number of legal actions against DEP for coal ash environmental violations is suggestive of the extent of the problem. Witness Lucas asserted that DEP non-compliance with NPDES permits and state groundwater rules would in probability have led to environmental cleanup costs even if CAMA and the CCR Rule had not been adopted, and that the costs of impoundment closures under CAMA and the CCR Rule overlap what would otherwise have been coal ash cleanup costs under existing state and federal environmental laws and regulations. Based on DEP's culpability for environmental violations, witness Lucas testified that an equitable sharing would be appropriate, whereas it would be unreasonable and unjust to burden ratepayers with all the coal ash- related costs when ratepayers were not culpable for the environmental violations. (Tr. Vol. 18, pp. 282-85)

In supplemental testimony, witness Lucas made some corrections to his initial testimony, and submitted Revised Lucas Exhibits 5 and 6. The revisions to Exhibit 5 corrected - and lowered - the number of NPDES permit violations he found, and further noted that the number of NPDES violations did not include unauthorized discharges (i.e., seeps) that are violations of G.S. 143-215.1. The revisions to Exhibit 6 identify which groundwater exceedances are violations of environmental regulations, and which have yet to be determined as violations versus natural background levels. (Tr. Vol. 18, pp. 289-90)

Public Staff Witness Maness proposed seven adjustments with respect to coal ash costs. (Tr. Vol. 18, pp. 298-99.) His adjustments for implementing witnesses Garrett and Moore's recommendations, allocation factors, addition of return on deferred coal ash expenditures from September 2017 through January 2018, and use of a mid-month cash flow convention are covered elsewhere in this Order. Witness Maness noted that the Public Staff did not oppose the Company's request in Docket No. E-2, Sub 1103, to defer coal ash costs that had been recorded as AROs into a regulatory asset for regulatory accounting purposes. He recommended that coal ash costs incurred from January 2015 through August 2017 be allowed as a deferral and that the costs be amortized over a 28-year period. He revised the amortization period to 26 years in his supplemental testimony, based on the cost of capital in the Stipulation between DEP and the Public Staff. (Tr. 18, pp. 336) He also proposed that there be no return allowed on the unamortized balance of the deferred costs. The purpose of the 26-year amortization period in conjunction with no return on the unamortized balance is to create a 50%-50% sharing of the deferred coal ash costs between ratepayers and shareholders.

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

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

Witness Maness recommended three major[1] adjustments to the amount of coal ash management costs subject to deferral. (Tr. 18, pp. 304-05) First is the removal of $80.5 million on a system basis, pursuant to witnesses Garrett and Moore's recommendation related to unnecessary costs for removal of coal ash from the Sutton plant to the Brickhaven site. Second is the removal of $45.6 million on a system basis, pursuant to witnesses Garrett and Moore's

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

recommendation related to unreasonable costs for coal ash processing at the Asheville plant. This amount was reduced to approximately $29 million in Public Staff supplemental testimony. (Tr. 18, p 335) Third is the removal of $6.7 million on a system basis, pursuant to the Lucas recommendation related to costs for extraction wells and treatment of contaminated groundwater. In addition, witness Maness noted that recovery of certain expenditures incurred in the 2015 and 2016 timeframe should be provisional because, as noted in the testimony of witness Lucas, the reasonableness of those expenditures is subject to pending legal determinations. (Tr. Vol. 18, p. 303) For all the foregoing adjustments, witness Maness was implementing, for accounting purposes, the recommendations sponsored by other Public Staff witnesses.

For the "equitable sharing" adjustment, witness Maness provided the substantive support for the recommendation, in addition to the support provided by witness Lucas. (Tr. Vol. 18, pp. 308-16) He testified that the five-year amortization period proposed by DEP was too short for the magnitude and nature of the Company's coal ash costs. (Tr. Vol. 18, p. 308) He advocated a 26-year amortization period, with no return on the unamortized balance, because the result would create an equal sharing of responsibility for coal ash costs between ratepayers and shareholders. He recommended the 50%- 50% equitable sharing for all the January 2015 through August 2017 coal ash costs deferred by the Company, except for costs that were the subject of disallowance recommendations as noted in the preceding paragraph.

Witness Maness provided two reasons for his equitable sharing recommendation. (Tr. Vol. 18, p. 309) First, as addressed in more detail by witness Lucas, "the extent of the Company's failure to prevent environmental contamination from its coal ash impoundments, in violation of state and federal laws, supports ratemaking that leaves a large share of the costs for DEP shareholders to pay." Second, there is ample support in prior Commission orders and case law for equitable sharing: past cases involving costs of abandoned nuclear construction and for environmental cleanup of manufactured gas plant facilities resulted in costs being shared between ratepayers and shareholders.

In terms of legal support for his recommendation, witness Maness noted that in State ex rel. Utilities Com. v. Thornburg, 325 N.C. 463, 385 S.E.2d 451 (1989), the North Carolina Supreme Court upheld the equitable sharing of nuclear abandonment costs through an amortization over a period of years with no return on the unamortized balance. A similar result was ordered for environmental costs incurred by Public Service Company of North Carolina, in connection with cleanup of manufactured gas plants, in Docket No. G-5, Sub 327 (1984). (Tr. Vol. 18, pp.310-13)

Witness Maness sought to distinguish the 2016 DNCP rate case, where the Public Staff did not propose an equitable sharing of coal ash costs and reached a settlement with that utility. (Tr. Vol. 18, pp. 315-16) He stated that the magnitude of costs is one reason for the different recommendation, and the paid to date system costs for coal ash in the DNCP case were only about 19% of the paid-to-date system costs for DEP. He further pointed out that the stipulation in the DNCP case made clear that the amortization of future CCR expenditures would be decided on a case-by-case basis.

Finally, witness Maness recommended that DEP be allowed to defer coal ash management costs incurred after August 31, 2017, into an ongoing regulatory asset/liability. He recommended that DEP be allowed to accrue a return on coal ash costs accumulated in the regulatory asset post-August 2017. The return would be the Company's net of tax rate of return, net of associated accumulated deferred income taxes. Any disallowances, and any equitable sharing through amortization with no return, would be determined in the next DEP general rate case for the coal ash costs deferred to the regulatory asset. Witness Maness opposed the Company's proposal of a "run rate" of approximately $129 million for ongoing rate recovery of estimated future coal ash costs. He testified that the run rate could make future equitable sharing of the costs of coal ash much harder to achieve. He conveyed advice of counsel that any attempt to achieve equitable sharing in the run rate by reducing it to recover only part of the coal ash expenses would be open to legal challenge. (Tr. Vol. 18, pp.316-18)

7. <u>Company Witnesses – Rebuttal Testimony</u>

<u>Kerin</u>

Company witness Kerin's rebuttal testimony responded to the direct testimony of Public Staff witnesses Garrett and Moore and CUCA witness O'Donnell. Witness Kerin noted that witnesses Garrett and Moore conducted a thorough and principled analysis of the costs that DEP incurred to comply with the CCR Rule and CAMA, and he agreed with the majority of their conclusions. He testified further, however, that based on a complete review of the applicable facts, including several overlooked key facts and sets of information, he opposed witnesses Garrett and Moore's suggested disallowances of the Company's coal ash disposal costs. (Tr. Vol. 20, pp. 30-32, 56.)

First, he disagreed with their conclusion that DEP could have built an on-site landfill at the Sutton site in place of the arrangement that DEP has with Charah, Inc., to transport CCRs to the Brickhaven Mine when DEP first started moving coal ash from the site, and with the associated $80.5 million suggested disallowance. Witness Kerin explained that DEP would have been unable practically and in compliance with CAMA to build an onsite landfill at Sutton under the timeframes witnesses Garrett and Moore suggested. He also maintained that, in his view, the lack of any limitation on the moratorium with regard to the Asheville and Sutton existing basins in the statute indicated the General Assembly's intent that DEP was prohibited from constructing a CCR landfill within the areas formerly used for storage coal ash. He also discussed additional regulatory limitations that existed in 2014 and 2015 regarding the construction of CCR landfills in the footprint of existing CCR surface water impoundments. Witness Kerin also explained how witnesses Garrett and Moore made incorrect assumptions concerning the Company's ability to permit and construct a CCR landfill using a "perfect world" scenario without considering the inherent uncertainty of any type of landfill, especially a CCR landfill, particularly during the regulatory and political environment that existed in 2014. He identified reasons DEP should not have started permitting the design for an on-site landfill at Sutton in June of 2014 as witnesses Garrett and Moore suggest. (Tr. Vol. 20, pp. 32-41, 56.)

Finally, with regard to Sutton, witness Kerin explained why the two landfill liner components that witnesses Garrett and Moore excluded from their hypothetical cost calculation are required for this location and were prudent to include in the new landfill design. (<u>Id.</u> at 50-51.) Witness Kerin testified that the unique location of the newly constructed Sutton landfill, being immediately adjacent to the existing coal ash surface impoundments, required use of the liners to effectively monitor the new landfill. The additional liners are necessary for the new CCR landfill design to be able to distinctly monitor the landfill's performance separate and apart from any influence that the adjacent older coal ash basins may be having, both now and in the future. Otherwise, it would be difficult to discern if the new landfill liner system was operating properly (or leaking), or whether groundwater monitoring wells around the landfill were actually detecting an effect from the adjacent coal ash basins.

Witness Kerin also disagreed with Garrett and Moore's conclusion that DEP could have built an on-site landfill at Asheville site rather than contract with Waste Management, Inc. to transport CCRs to an off-site location and the associated $45.6 million suggested disallowance. He testified that the issues that affected the Company's decisions with regard to Sutton, discussed above, also applied to the Asheville site and would similarly have made an on-site landfill option infeasible. He explained that in addition, while the Company had previously—as early as 2007— researched CCR landfill construction at Asheville, CAMA and the Mountain Energy Act of 2015 changed the technical feasibility of an on-site CCR landfill, giving the short time period to replace the coal-fired generation by 2020, and close both coal ash basins by 2022. (Tr. Vol. 20, pp. 33, 42-44, 56-57.) He also disagreed with the quantity of coal ash excavated and transported off site that Garrett and Moore used in its analysis of Asheville, which does not account for over 500,000 tons of coal ash. He testified that the price per ton for coal ash disposal that DEP paid at the Asheville site, reflected in the all-in blended contract rate DEP had for the initial scope of work, was reasonable, and that with the benefit of experience the Company was able to negotiate a more favorable all-in rate in December 2016. Witness Kerin therefore recommended that, if the Commission does find the initial all-in rate to be excessive, a disallowance of approximately $9.5 million could be justified in lieu of the O&M disallowance of approximately $14 million (which witness Kerin calculated after adjusting for the proper coal ash amount). Witness Kerin noted that witnesses Garrett and Moore received information from DEP in response to multiple questions that asked for coal ash quantities at different times and in different ways. He explained each of the variations in coal ash amounts contained in witnesses Garrett and Moore's Exhibit 5. (Tr. Vol. 20, pp. 44-46, 57.)

Witness Kerin addressed the concerns that Garrett and Moore raised with respect to potential for costs to be imprudent in the future if these certain conditions arise. First, witness Kerin testified that potential fulfillment costs related to the Brickhaven and Colon mines are common practice for contracts that require a contractor to develop some large infrastructure to perform a needed service, and that the fulfillment fee was negotiated to fairly and reasonably in acknowledgement of Charah's risk exposure. Second, witness Kerin noted with regard to future water treatment costs that DEP has increasingly accurate cost estimates for each site as its plans develop, on balance water treatment costs are decreasing, and DEP does not object to the Commission and interested stakeholders tracking these costs as they develop. Third, witness Kerin stated that DEP will seek variances to any deadlines, as applicable, where doing so would be in the best interest of customers, and noted that he reads G.S. 130A-309.215 to mean that DEQ's variance authority applies equally to the closure provisions for H.F. Lee, Cape Fear, and Weatherspoon as to other sites. Finally, witness Kerin noted that DEP is in the later stages of contract negotiation for the sale of processed coal ash and expects to have an executed agreement by March 2018, and the first beneficiation unit that witnesses Garrett and Moore are concerned about will come online in late 2019. (Tr. Vol. 20, pp. 33, 47-50, 57.) Also with regard to beneficiation, he explained that DEP identified the Buck, H.F. Lee, and Cape Fear sites for beneficiation as providing the best economic value for customers while complying with CAMA, and that the Company entered into an agreement for Weatherspoon as well but the cement companies could not take enough coal ash to qualify that site under CAMA. (Id. at 51-52.)

Witness Kerin also testified that CUCA witness O'Donnell's analysis and recommendation of a 75% disallowance of the Company's coal ash costs relies on multiple analytical flaws that are fatal to his conclusion. Specifically, witness Kerin disagreed with witness O'Donnell's conclusion that the national comparison of CCR assets retirement obligation, or ARO, amounts shows that the Company's ARO is overstated by 75%, and enumerated 22 factors that he states witness O'Donnell does not appear to have considered, which witness Kerin explained must be accounted for in order to seriously attempt this type of analysis. Witness Kerin recommended that the Commission consider the reasonableness of the Company's ARO amount on its own merits, based on the facts of this case, and without regard to witness O'Donnell's proposal. (Tr. Vol. 20, pp. 52-55, 58.)

Wright

On rebuttal, Company witness Wright testified to several issues related to the recovery of costs associated with coal ash remediation expenses raised in the testimonies of Public Staff witnesses Lucas and Maness, AGO witness Wittliff, and CUCA witness O'Donnell. He stated that, overall, the theories underlying these witnesses' recommended disallowances of these costs are unfounded, do not justify disallowance, and should be rejected by the Commission. (Tr. Vol. 20, pp. 127-28, 170.)

Witness Wright first disagreed with Public Staff witness Lucas' recommendation to disallow 50% of the Company's remaining coal ash costs after accounting for certain other disallowances that he and Public Staff witnesses Garrett and Moore recommend. Witness Wright stated that this recommendation does not align with the appropriate regulatory standard for denial of cost recovery, including recovery of environmental compliance costs, which he explained is a finding that specifically identified costs are imprudent or unreasonable. He noted that witness Lucas did not find the Company imprudent for most of the coal ash-related cost, nor did witness Lucas find the Company's costs to be unreasonable. Instead, witness Wright explained, witness Lucas asked the Commission to disallow these costs apparently based on the theory that the Company acted poorly in its historical coal ash disposal methods and on speculation of past or future environmental compliance issues. Witness Wright stated that it is not proper for the Commission to deny cost recovery based on speculation of future findings of violation, or to impose a sharing of costs based upon an undefined culpability standard. (Tr. Vol. 20, pp. 128-29, 131-35, 170-71.)

Witness Wright also explained that the proposed sharing of cost is also inconsistent with Commission precedent and with the Public Staff's own position on the recovery of coal ash disposal cost in Dominion's 2016 base rate case. In that case, he recalled, Dominion requested a recovery of CCR Rule compliance costs up to and through 2016. He explained that those expenditures included closure and related costs for the Chesapeake Energy Center, even though a court found past violations of the Clean Water Act at this location. He stated that the Commission concluded that the recovery of these costs, as provided in the stipulation entered into in that case by the Public Staff and Dominion, was just and reasonable. He stated his opinion that the CCR cost recovery methodology applied in the Dominion case was correct and should be applied in the same way for DEP. (Tr. Vol. 20, pp. 135-37, 141-42, 171-72.)

Witness Wright also testified that the Public Staff's suggestion that the Commission's treatment of abandoned nuclear plants supports its proposed cost sharing proposal is not appropriate, because abandoned nuclear plant costs are not comparable to CCR costs. He explained that the Commission has found abandoned nuclear cost not to be used and useful, and thus not eligible for rate-based treatment. In contrast, he noted, the coal plants associated with these costs and the related coal ash disposal facilities have been used and useful in providing low-cost, reliable power to North Carolina customers for more than 70 years, and will continue to be used and useful. He stated that this is consistent with the recent Dominion case, where the Commission found that CCR repositories were and continue to be used and useful, were therefore not abandoned, and were therefore eligible for recovery through amortization and a return on the unamortized balance, similar to other types of used and useful property. (Tr. Vol. 20, pp. 137-38, 142-44, 172.)

Witness Wright went on to state that the Commission's treatment of environmental cleanup of manufactured gas plants also does not support the Public Staff's proposed cost sharing, and referred to his direct testimony that MNG plant costs differ from coal ash disposal costs, both in terms of the time that elapsed between the actual usage of the facility and the environmental-related cost recovery, and in terms of ownership. In addition, he noted that MNG facilities, like abandoned nuclear plants, were found not to be used and useful. He noted further that there is no need to rely on a 23- year-old cost recovery example from a different industry, dealing with assets last used more than 70 years ago, when the best example of the Commission's treatment of coal ash disposal costs can be found in the Dominion case that was decided one year ago. (Tr. Vol. 20, pp. 138-40, 173.)

Witness Wright also testified that the 28 (26)-year amortization period proposed by the Public Staff is not justified either by their cost sharing theory, or by defining these costs as being extremely large. He explained that adoption of this proposal would undermine the basic cost of recovery principles embodied in North Carolina utility regulation and would subject utilities to an unknowable and ill-defined cost recovery standard. He explained further that it could also result in a perception of the state's utilities as riskier, leading to higher cost of capital and cost of service. (Tr. Vol. 20, pp. 140-41, 144-45, 173-74.)

Witness Wright disagreed with witnesses that claimed that Duke Energy substantially caused the CCR Rule and CAMA and that, therefore, all costs incurred to comply with these requirements should be disallowed. He referenced his direct testimony that while the timing of CAMA may have been influenced by the Dan River accident, he cannot conclude that the North Carolina legislature would have adopted a different substantive law without Dan River. He noted in addition that there are numerous examples of North Carolina lawmakers and regulators adopting environmental policies, not only specific to this state, but stricter than national or neighboring states' policies. He also noted that state-specific actions to address CCRs have been adopted in a number of jurisdictions. Based on all these factors, he opined that North Carolina likely would have adopted a state-specific CCR regulation regardless of the Dan River accident. (Tr. Vol. 20, pp. 145-50, 174.)

Witness Wright also expressed his opinion that CAMA was not intended to be a punitive law. He noted that CAMA does not contain any punitive limitation on cost recovery except for the provision for certain spills to surface water. He also noted that attempts to further restrict coal ash disposal cost recovery under this law have been tried three times, but in all three cases, amendments or laws to disallow cost recovery were defeated. He stated that the General Assembly has shown that it will, when it wants to, adopt specific cost recovery restrictions with other state environmental laws, as exemplified by the Clean Smokestacks Act. In contrast, he explained, the legislature's affirmative decision not to disallow prudently-incurred costs related to CAMA, and not to adopt subsequent proposals to disallow such costs, indicates that CAMA was not meant to be punitive with regard to cost recovery, but rather intended to leave cost recovery determinations to this Commission's oversight and sound regulatory policy. (Tr. Vol. 20, pp. 151-53, 174 -75.)

With regard to coal ash litigation costs, witness Wright reiterated that DEP has excluded from its recovery request all fines, penalties, and fees related to the Dan River accident. (Tr. Vol. 20, 164-65.) He also opined, however, that witness Luças' apparent position that all of the Company's costs to defend lawsuits should be disallowed recovery, regardless of whether the Company is ultimately found liable or not, is not supported by precedent or sound regulatory policy. First, the Glendale Water case does not support this theory. In addition, he noted that the Commission has recognized that settlements and litigation defense costs, when reasonable and prudent, are recoverable costs, and that the Commission and the Public Staff have also recognized that settlements are beneficial. He concluded that the Public Staff's apparent position in this case, that, if DEP did not commit violations, it should not settle, is inconsistent, not only with public policy but also with the positions it has previously taken with regard to settlements. With respect to potential settlements of coal ash disposal methods at the Mayo and Roxboro facilities, he noted that this position also leaves the Company in an untenable position, since witness Lucas testifies both that DEP should spend whatever amount is required in order to never have a groundwater issue, and that, if in the course of any settlement as to Mayo and Roxboro, DEP agreed to a coal ash remediation methodology and costs beyond the minimum required by law, those costs should be disallowed, even if that methodology would be more likely to prevent future groundwater issues. (Tr. Vol. 20, pp. 153-61, 175-77.)

Witness Wright also addressed witness Lucas' argument that North Carolina's 2L rule imposes strict liability, such that the Company must take any action, regardless of either cost or industry practices, to avoid or cure a violation of this rule, and his contention that, because water extraction and treatment required under the CCR Rule and CAMA have a curative effect on past alleged 2L violations, the cost of those activities, \$6.7 million in this case, are not recoverable. Witness Wright testified that there is no evidence that the 2L rule was intended as strict liability and that, regardless, the standard for cost recovery is reasonableness and prudency, not strict liability. He stated that adoption of the Public Staff's position would effectively require that, with any alleged or potential violation, the utility would be expected to immediately undertake remediation, regardless of the expense, and potentially even nonstandard, experimental environmental compliance projects that could not only be costly, but ineffective. (Tr. Vol. 20, pp. 161-62, 177.)

While witness Wright agreed with witness Lucas that DEP could, in theory, have undertaken coal ash disposal projects above and beyond any legal requirements or industry standards, he noted that those costs would have been subject to high scrutiny, and the Company likely would have been accused of gold-plating. More generally, he explained that it is not appropriate to apply the benefit of hindsight to judge whether expenditures that DEP made under the circumstances known at the time were reasonable. (Tr. Vol. 20, pp. 163-64, 177-78.)

For similar reasons, witness Wright also disagreed with the Public Staff's recommendation of provisional cost recovery for coal ash expenditures prudently incurred from January 2015 through August 2017, based on the argument that the appropriateness of such recovery may depend on the outcome of legal determinations. He noted first that this would appear to be retroactive ratemaking. He also stated that the standard is that the utility makes the best possible decisions on expenditures based on the information available at the time, and determinations of the reasonableness and prudency of these costs should not depend on future outcomes of legal proceedings but what was known or knowable at the time. (Tr. Vol. 20, pp. 165-66, 178.)

Witness Wright testified further that the Commission should reject AGO witness Wittliff's recommendation that DEP only be allowed to recover costs required to comply with the CCR Rule, and not any costs related to CAMA. He noted that witness Wittliff neither quantified the disallowance he recommends, nor offered any regulatory policy or logical support for his position, and stated that his proposals are unsupported by good regulatory policy, precedent, or logic. (Tr. Vol. 20, pp. 167-68, 178-79.)

Finally, witness Wright opined that the Commission should reject CUCA witness O'Donnell's recommendation that 75% of the Company's environmental compliance costs should be disallowed based on a comparison of the alleged national asset retirement obligations, or ARO, amounts relating to CCRs. He stated further that the Commission should reject any disallowance, especially one as substantial as the amount witness O'Donnell recommends, that is not based on facts and evidence that have been proven and verified as mathematically correct and substantially significant, and that to do otherwise would constitute poor regulatory policy and would bearbitrary. (Id. at 168-69, 179.)

At the hearing, witness Wright explained during cross-examination by counsel for the Sierra Club the decision tree that the Commission uses to determine whether costs are recoverable and how that recovery will occur. He explained that the first question is whether the costs were reasonable and prudent in providing service to ratepayers, and, if so, the next question is whether they were used and useful, and, if used and useful, the last stage is to consider what outcome would be fair and equitable. He explained further that it is at the last stage where the Commission has leeway to consider different rate designs to achieve a fair and equitable result. He stated that the Public Staff's equitable sharing proposal does not follow this decision tree, but attempts to impose a splitting of costs with no consideration for reasonableness and prudence, etc. He noted that that is a cost recovery approach that he has not seen in his experience. (Tr. Vol. 20, pp. 186-88.)

Witness Wright testified in response to questions by counsel for the Public Staff that the fact that DEP has an exceedance or even a violation is not indicative or necessarily tied to the recoverability of costs DEP is seeking in this case. He explained that if DEP has a violation and admitted wrongdoing, or an adjudicated proceeding determined there was wrongdoing, then those costs or fines should not be recovered. He testified that that is different from DEP's having to now comply with new standards; in terms of costs associated with new obligations, he considers those long-term compliance costs. (Id. at 209-11.) In response to cross-examination regarding this case as compared to the 2016 Dominion case, witness Wright clarified that he believes the run rate that DEP has proposed in this case is reasonable. (Id. at 212-13.) Witness Wright also clarified that references to the Dan River spill in the final CCR Rule indicate that the EPA cited that event as evidence that the rule was needed, not as a factor that changed the substance of the rule itself. He testified further that references to Dan River in the initial version of CAMA support his position that Dan River influenced the timing but not the substance of that law. (Tr. Vol. 21, pp. 14-17.) He also noted that, while the CCR Rule does not require mandatory excavation, based on his discussions with witness Kerin, witness Wright believes that site studies and engineering analysis that would have been done in support of CCR led to the same closure methodologies that CAMA requires. (Id. at 18-19.) Finally, witness Wright clarified that the Public Staff's position, that DEP should have spent any amount required to prevent any groundwater contamination years ago and risk disallowance of those costs, but also that DEP should not be able to recover the costs it has now prudently incurred to comply with new laws and regulations, is inconsistent. (Id. at 33-35.)

Wells

Company witness Wells testified that DEP's compliance record with respect to NPDES permits has been exemplary. He stated that the Company has consistently complied with the terms of its NPDES permits over the years, and that, of well over 70,000 data points, it has had fewer than 200 permit violations, which is less than one half of 1% at all seven of its facilities in the last 10 years. Specifically with regard to Asheville, Cape Fear, H.F. Lee, Sutton, Roxboro, and Weatherspoon plants, witness Wells noted that DEP has had no more than 20 NPDES permit exceedances during this time frame. He stated that, when compliance issues have arisen at individual plants, DEP has addressed those issues with regulators. (Id. at 62-63, 88-89.)

Witness Wells continued that, in his direct testimony and original Exhibit 5, witness Lucas asserted that DEP has 2,172 NPDES permit violations over the past 10 years. He noted that witness Lucas included in that total groundwater data associated with reported monitored exceedances of groundwater quality standards. Witness Wells emphasized, however, that groundwater data are not permit violations. Rather, he explained, these permits require the Company to monitor groundwater in compliance with a monitoring plan and report the data to the DEQ. He explained that a monitored exceedance of a groundwater standard is not a permit violation, and DEQ has never issued DEP a notice of violation identifying groundwater data as the basis of a permit exceedance. He concluded that the Public Staff has conflated these two concepts. (Id. at 64-66, 74-76, 89.)

Witness Wells explained further that exceedances of groundwater standards and the existence of seeps in the vicinity of the Company's coal ash basins do not indicate mismanagement or poor compliance programs. He stated that the existence of groundwater exceedances at or beyond the compliance boundaries at DEP sites is rather a function of where these sites are on the timeline of groundwater assessment and corrective action under modern laws that have changed the way unlined basins are viewed. He testified that the Company's decision to use unlined basins to treat coal ash transport water was reasonable and consistent with the approach employed across the power industry at the time that the basins were built. He noted that each DEP site had been properly and legally operating an unlined basin for at least a decade before the adoption of any regulatory requirements related to groundwater corrective action. He noted further that as requirements changed over time, DEP has taken every action required by DEQ's groundwater rules, and later by the CAMA and the CCR Rule, to address groundwater impacts as they have been identified. (Id. at 66, 76-77, 91-92.)

For similar reasons, witness Wells also disagreed with the Public Staff's suggestion that any exceedance or violation of water quality regulations, no matter how minor or how long ago, leads to the denial of cost recovery for any activity that acts to "cure" the impacts of the violation. In addition to reiterating that not all exceedances of the 2L standards amount to a violation that requires corrective action under the 2L rules, witness Wells stated that even when an exceedance requires corrective action, the groundwater rules do not treat the exceedance the same way as, for example, the Clean Water Act treats an exceedance of an NPDES permit limit. When the latter is violated, he explained, the permittee is immediately subject to an NOV and penalty, and must ensure the next discharge complies with the permit limit or risks a new NOV and escalating penalty. He stated that in those circumstances, it would be reasonable to say that allowing the violation to continue without addressing it is mismanagement. He contrasted this with groundwater standards, under which an exceedance does not immediately result in an NOV and penalty. Instead, he explained the owner/operator must report the exceedance and work with the DEQ to determine whether it was due to permitted activity, assess the extent of the exceedance, and undertake corrective action. Any newly measured exceedances do not require a further site assessment and do not result in additional or escalating penalties, but are actually expected as additional assessment prior to corrective action is conducted. He testified that the 2L rules' correction action provisions are deliberately designed around the idea that older facilities, built before liners were a regulatory obligation, were likely to have associated groundwater impacts, that such impacts were not the result of regulatory noncompliance, and that they should be addressed in a measured process. He concluded that compliance with this process is not mismanagement and should not be held against DEP with respect to cost recovery. (Tr. Vol. 21, pp. 79-80.)

Witness Wells noted at the hearing that, after he filed his rebuttal testimony, witness Lucas filed supplemental testimony that acknowledged the distinction between exceedances and violations. Witness Wells noted that, in his supplemental testimony, witness Lucas admitted that most of the instances of what he had called NPDES permit violations in his original Exhibit 5 are not NPDES permit violations, and submitted a Revised Exhibit 5 that removes groundwater exceedances from the total number of NPDES permit violations. Witness Wells stated that this change reduced the total number of witness Lucas' alleged permit violations to 458, a reduction of about 79%. (Id. at 89-90.)

Witness Wells continued that, of the remaining 458 allegations, 199 are listed as occurring at the Mayo plant, which the Company acted quickly to address by installing the Zero Liquid Discharge system. He noted that the other 255 alleged violations listed in witness Lucas' revised Exhibit 5 are new alleged failure to monitor events. As with the original Lucas Exhibit 5, he explained, this number of failure to monitor violations is inaccurate and significantly overstated. He stated that the vast majority of these alleged violations were reviewed by DEQ staff at the time of the events and determined not to be violations. He also stated that the documents relied on by witness Lucas clearly indicate where DEQ made that determination that no action was warranted, but that witness Lucas did not fully incorporate that information into his evaluation. He concluded that removing the Mayo specific events from witness Lucas' corrected 458 number leaves only four permit exceedance violations for the other six DEP sites in the last 10 years, according to witness Lucas' revised exhibit. (Id. at 90.)

Witness Wells noted further that after he filed his rebuttal testimony, witness Lucas revised his Exhibit 6 to also distinguish between groundwater exceedances and groundwater violations. Witness Wells explained that only exceedances beyond the compliance boundary and above background concentrations required further action, and that DEQ is currently in the process of finalizing background levels for the DEP basins. Witness Wells pointed out that witness Lucas appeared to have removed background wells and invalid samples from his original Exhibit 6, and that the Revised Exhibit 6 reduced the number of alleged violations for 12 of the 23 parameters, reducing the total approximately 65%. He pointed out also, however, that these changes still do not take into account consideration of the fact that CAMA requires comprehensive site assessments of groundwater, which increased the number of monitoring wells and the number of samples to accurately characterize the site. (Id. at 21.)

In his rebuttal, witness Wells disagreed with witness Lucas' apparent contention that DEP should have moved well ahead of accepted science, regulatory requirements, and industry practice and should have begun taking measures to prevent any and all groundwater quality issues without regard to the cost of those measures or whether sufficient and proven technology existed at the time to address the conditions at the site. He opposed the suggestion that DEP only engaged in comprehensive groundwater monitoring and remediation when forced to do so by CAMA and other developments. He explained that the Company began monitoring groundwater at Sutton in 1984, Roxboro in 1987, Weatherspoon in 1990, and the remaining sites in or around 2006. He noted that, in 2011, DEQ prescribed a process to be undertaken by DEQ and utilities upon the identification of a groundwater exceedance near a coal ash pond, which included performance of an assessment to determine the cause of the exceedance and, as necessary, develop a Corrective Action Plan consistent with North Carolina groundwater rules. He stated that under that process, only after a utility failed to undertake corrective action when directed to do so would DEQ consider pursuing enforcement. He stated that at all times DEP has cooperated with the department in this corrective action process and continues to do so to this day. (Tr. Vol. 21, pp. 67-73, 92- 93.)

Witness Wells also testified that North Carolina's groundwater laws were not intended, as witness Lucas contends, to be punitive. He explained that, for historical sites such as those at issue in this case, this state's groundwater regulations and the DEQ's practices and policies are focused on environmental protection rather than culpability, that the required corrective action is based upon science and not an assessment of wrongdoing. He stated that, in evaluating Corrective Action Plans, DEQ considers numerous factors, including the extent of any threat to human health, impact on the environment, available technology, potential for natural degradation of the contaminants, and cost and benefits of restoration. He cited the example that the groundwater exceedances at the Sutton site were not the result of mismanagement. He stated that the extraction and treatment costs witness Lucas recommends for disallowance relate to work that DEP agreed to accelerate and would be required in the normal course as a part of the groundwater corrective action under the CCR Rule and CAMA. (Id. at 73-74, 93-94.)

At the hearing, in response to questions from counsel for the Sierra Club, witness Wells characterized the 2L rule as a process that is set up to establish groundwater standards around the basins, that recognizes that there is potential for impact to groundwater beneath the basins, and that established compliance boundaries 500 feet from the waste boundaries. He explained that the 2L rule structure is that upon detection of a contaminant above a standard or above background at the compliance boundary, one proceeds to the next step, assessment and, depending on the assessment, proceed to corrective action. He noted that the rule is not, particularly with historical, lawfully designed sites, intended to be punitive. He stated that noncompliance arises if the company fails to take action upon detection, fails to follow the process set forth in 2L. He testified that the policy statement contained at Section 2L.0103 is consistent with that purpose. (Tr. Vol. 21, pp. 102-04.) In response to further questioning, witness Wells clarified that groundwater corrective action plans are conducted in parallel with basin closures, and that the groundwater corrective action plans will consider the various methods of closure to understand those impacts to groundwater. He also noted that, regardless of the closure method that DEP selects, groundwater can always be addressed separately from the closure method. (Id. at 110.)

In his rebuttal, witness Wells also disagreed with witness Lucas that the amount of litigation regarding the Company's coal ash basins suggests that the Company was imprudent in managing coal ash. He opined that the amount of litigation has been driven by nongovernmental organizations that have been pressing for complete excavation of coal ash from all basins across the Southeast. He stated that DEP has appropriately been opposed to this, arguing instead that final closure methods should be dictated by site-specific characteristics based upon science, regulatory policy, and the best interest of our customers. He noted that DEP has resolved such litigation where CAMA made the suit moot and where science and engineering supported closure by excavation, and that the Company continues to vigorously litigate cases where other closure methods are more or equally protective of the environment at less cost. (Id. at 77-78, 94.)

Witness Wells' rebuttal also addressed seeps. He explained that all earthen impoundments seep, and that DEQ's dam safety regulations acknowledge this. He stated that EPA first directed permitting authorities to address seeps in 2010, and at that time, the Company engaged DEQ to determine the appropriate approach to address seeps and began including them in permit applications. He noted that DEQ did not consider seeps to have a significant environmental impact. He also noted that EPA and DEQ did not appear to agree on the appropriate approach to address seeps. He stated that, absent the CCR Rule or CAMA, the existence of seeps in a basin would not on its own automatically trigger basin closure and should not, therefore, impact the Company's ability to recover its CCR environmental compliance costs. He testified that, although closing basins would be one way to address seeps, it would be the most drastic of several possible remedies, and both EPA and DEQ have stated that seeps can be addressed by permitting or rerouting, among other options. (Id. at 81-85, 95.)

Finally, witness Wells disagreed with witness Lucas' suggestion that DEP caused the creation and adoption of the CCR Rule. He testified that the environmental regulatory regime is an ever-evolving body of law, and the EPA engaged in more than two decades of studies before it finally issued a proposed CCR Rule in 2010. Through this process, he noted, the EPA identified 150 cases in over 20 states involving over 25 utilities and government facilities that involved groundwater damage with at least a potential link to coal ash, but determined that immediately closing basins, which would require shutting down operating coal plants, would be more harmful than taking a measured approach. (Id. at 85-87, 95-96.)

At the hearing, in response to questioning by counsel for the AGO and Public Staff, witness Wells explained that previous reports, analyses, and communications regarding how the Company's coal ash basins will be managed indicate that prior to CAMA and CCR Rule the regulatory approach and understanding of groundwater associated with coal ash basins was maturing. For example, he stated that a 2004 report analyzing long term coal ash strategy for the Sutton plant specifically appeared to have been evaluating alternatives for that location given the evolving regulatory scrutiny of coal ash basins and how the Company would manage that and any environmental impacts going forward. Similarly with respect to a 2014 executive order from the governor of North Carolina, which stated that the issue of coal ash storage had not been adequately addressed in the state for decades, he testified to his belief that this statement was not a reflect of any mismanagement or acts or omissions on Duke's part, but of an understanding of the maturity and evolving views of coal ash management throughout the country, and of a recognition that historical designs and management practices needed updating. He also testified that the Company's guilty plea in the federal criminal action was not a reflection of mismanagement of coal ash by the Company as a whole. He acknowledged that the Company took responsibility for the allegations, cooperated with government, and based on the facts at that time at those sites, agreed the Company did not meet its own standards. (See Tr. Vol. 21, pp. 123-25, 145-46.) Witness Wells also noted that the full context of the depositions with DEQ personnel demonstrates the normal cooperative process between the agency and the Company, in which DEQ has final authority. (Id. at 136-39.) In response to questioning from the Commission, witness Wells confirmed that DEP began voluntary monitoring of groundwater in 2006 at facilities where monitoring was not already required. He explained further that the Company was a member of the industry group (Utility Solid Waste Advisory Group) that worked with EPA to address emerging issues, and that as part of that group it agreed to implement groundwater monitoring at these sites and share the results with the EPA. He agreed that the Company considered it reasonable to begin the monitoring at that time even though it was not required, as part of the continued evolution and maturation of the understanding in the industry of environmental impacts of the basins. (Tr. Vol. 22, pp. 30-32.)

In response to questions by the Chairman, witness Wells testified that the testimony and evidence he observed during the hearing confirmed and strengthened his support for the positions contained in his pre-filed testimony. He explained that permit compliance in particular is a very complex, challenging issue, and that the Company's compliance record and his experience with respect to NPDES permit compliance has been outstanding. He noted that out of 70,000 data points on this subject, the evidence shows approximately 20 violations. He noted further to put that number in context that one of those violations was, out of 10 years of sampling at Asheville, one sample exceed the oil and grease limits, at 15.7 ppm vs. 15.0. And that a duplicate sample showed a level of less than 5, but could not be used due to its timing expiring. He explained that this example puts into perspective the violations that have been framed inaccurately during the proceeding. He also noted the response to his rebuttal that suggested that the Company missed sampling, and clarified that all of the 117 missed sampling events at H. F. Lee contained in witness Lucas' revised exhibits were incorrect, that in fact there were no missed sampling events. He explained that, for example, there was a flood event where the plant was in shutdown and there was no flow, and that he could provide similar explanations for each variance event. He noted that the record had so far not been clear on these points. (Tr. Vol. 22, pp. 43-45.)

Commission Determinations

The Commission has reviewed with care the evidence on the issue of CCR remediation cost recovery and the arguments and contentions of the parties. The Commission cannot agree with the ultimate positions of any party. The Commission rejects full recovery advocated by DEP, extensive disallowances advocated by others and the "equitable sharing" concept advocated by the Public Staff.

The Public Staff's Specific Cost Disallowance Proposals

The Commission must undertake a detailed analysis before any costs can be disallowed on the basis of findings of imprudence alone. 1988 DEP Rate Order at 15. The Public Staff undertook such an analysis of the Company's coal ash costs, and came up with three discrete and specific proposed disallowances. Two were presented through witness Lucas: first, $88,000 of legal expense associated with two litigation matters regarding alleged environmental violations, one brought by private parties and one brought by NC DEQ, and, second, approximately $6.7 million in groundwater extraction and treatment costs resulting from a settlement in the DEQ case, which witness Lucas attributes to past violations by the Company of North Carolina's groundwater standards (the "2L Standards"). Third, Public Staff witnesses Garrett and Moore recommended a disallowance totaling $109.8 million relating to the cost of off- site transportation and disposal of coal ash from the Sutton and Asheville Plants, on the grounds that prudence dictated that the coal ash be disposed of in on-site facilities to be constructed rather than being hauled off-site.

Lucas: Alleged Environmental "Violations"

The Public Staff, through witness Lucas, asserts that the rationale for disallowance of the litigation expense and groundwater costs is that these costs flow from "violations" of the law. (Tr. Vol. 18, p. 275.) Witness Lucas cites the Glendale Water case (State ex rel. Utils. Comm'n v. Public Staff, 317 N.C. 26, 343 S.E.2d 898 (1986)) for the proposition that the legal expense should be excluded. (Id.) In that case, the North Carolina Supreme Court held that legal expense associated with a penalty proceeding in which the utility had been found to have violated the law should be excluded. (Id.) Although he does not say so explicitly, the same rationale would apply to witness Lucas's exclusion of the groundwater extraction and treatment costs incurred in a settlement context.

The distinction between the Public Staff recommended adjustment and Glendale Water is that there is no finding in the litigation brought against the Company, or admission by the Company in that litigation, that any "violation" actually occurred. Witness Lucas's testimony that the legal expense and the groundwater treatment cost resulted from any "violation" is based on the "size of the settlements." (Tr. Vol. 18, p. 386.) The settlements referenced by witness Lucas amount in total to $7.25 million – $1.25 million to settle the private litigation, and $6 million to settle the

DEQ litigation.[1] Witness Lucas elaborated: "I made my [disallowance] decision on just the large amount – the millions of dollars of settlements [that] were paid by the Company, and I don't believe that the Company would have made those large settlement sums unless it believed it did have some fault." (Id. at 386-37.)

The Commission determines that the facts in this case and Glendale Water are distinguishable. Disputed matters are settled frequently, for many reasons other than settling parties' underlying view of the merits of the dispute. In this case, for example, the Company and the Public Staff have entered into a Partial Settlement which includes an ROE of 9.9% (versus the Public Staff's recommendation of 9.2%), and a capital structure of 52% equity and 48% debt (versus the Public Staff's recommendation of 50/50). This proposed settlement results in millions of dollars paid by customers over and above the Public Staff's pre-settlement position, but that does not mean that the Public Staff has disavowed its pre-settlement position.

The Commission determines that entering into a settlement does not equate to an admission of guilt or wrongdoing. The North Carolina Rules of Evidence prohibit parties from using the existence of a settlement as evidence of liability.[2] The Public Staff has defended as good regulatory policy the encouraging of reasonable and prudent settlements. In 2016, NC WARN filed a Petition for Rulemaking seeking to require settlements between the Public Staff and utilities to be made open to the public. (Tr. Vol. 20, p. 157); See also In the Matter of Rulemaking Proceeding to Consider Proposed Rule Establishing Procedures for Settlements and Stipulated Agreements, Order Declining to Adopt Proposed Settlement Rules, Docket No. M-100, Sub 145 (Mar.1, 2017) ("Settlements Order"). The Public Staff opposed NC WARN's petition, arguing that public policy favors settlements:

> [T]he Public Staff submits that settlements promote the informal exchange of ideas and information among the parties, the elimination of insignificant or noncontroversial issues ahead of an evidentiary hearing, informed decision making and the efficient administration of justice, especially in the complex matters that are typically before the Commission. Moreover, settlements result in savings to consumers by reducing litigation expenses that would otherwise be recoverable by utilities as a component of the cost of providing utility service.

(Tr. Vol. 20, pp. 157-158; Settlements Order at 3.)

Further, the Public Staff cited to North Carolina case law "touting the benefits of settlements" in business litigation. (Tr. Vol. 20, p. 158; Settlements Order at 3 (citing Knight Pub. Co., Inc. v. Chase Manhattan Bank, N.A., 131 N.C. App. 257, 262 (1998) (Knight)). The Public Staff relied on the principle articulated in Knight that North Carolina "law favors the avoidance of litigation," and a compromise made in good faith "will be sustained as not only based upon

[1] Witness Lucas acknowledges that the settlement amount is not included in the Company's cost of service, and that the Company is not seeking to recover it in rates. (Tr. Vol. 18, p. 277.)

[2] N.C. R. Evid. 408 ("Evidence of (1) furnishing or offering or promising to furnish, or (2) accepting or offering or promising to accept, a valuable consideration in compromising or attempting to compromise a claim which was disputed as to either validity or amount, is not admissible to prove liability for or invalidity of the claim or its amount. Evidence of conduct or evidence of statements made in compromise negotiations is likewise not admissible.").

sufficient consideration but upon the highest consideration of public policy as well." (Tr. Vol. 20, p. 158 (quoting Knight, 131 N.C. App. at 262 (emphasis added) (internal quotations omitted)). The Commission determines that it should not approve a disincentive to settle pending or future lawsuits.

These considerations likewise apply to the groundwater treatment costs witness Lucas seeks to disallow, which are the subject of the settlement agreement between DEQ and the Company (DEQ Settlement Agreement). (See Public Staff Wright Rebuttal Cross- Examination Ex. 7.)[1] The DEQ Settlement Agreement references in its recitals a DEQ "Policy for Compliance Evaluations" promulgated in 2011. It appears from the recitals and their description of that Policy that questions as to whether violations of the state's groundwater standards have occurred. (See DEQ Settlement Agreement, at 3, 4-5.) The recitals also indicate, with the passage of CAMA, that the Company would be required to close its coal ash basins, and that CAMA "dictate[d], in detail a procedure for assessing, monitoring and, where appropriate, remediating groundwater quality in areas around coal ash impoundments in North Carolina ...." (Id. at 3-4.) Further, in the recitals the DEQ acknowledged that the CAMA requirements were "designed to address, and will address, the assessment and corrective action" associated with alleged groundwater contamination. Because CAMA would require the Company to implement certain action, the Commission determines that it was reasonable for the parties to settle irrespective of whether the Company had committed violations of 2L Standards. Had the Company continued to litigate the matter in this circumstance, its actions may have been deemed by the Public Staff and this Commission to be imprudent, with a disallowance of the legal costs incurred in connection with continued litigation disallowed.

Here, the testimony of Company witness Wells is instructive. Witness Wells successfully countered witness Lucas's notion that the Company had experienced 2,172 NPDES permit violations over the past 10 years (See original Lucas Exhibit 5). Witness Lucas reduced the number of the alleged violations in his Supplemental Testimony to merely 458 violations. (Tr. Vol. 16, p. 369). Witness Wells testified that witness Lucas included in that total groundwater violations data associated with reported monitored exceedances of groundwater quality standards. Witness Wells testified that groundwater data are not permit violations. Rather, he explained, thesepermits require the Company to monitor groundwater in compliance with a monitoring plan and report the data to the DEQ. He explained that a monitored exceedance of a groundwater standard is not a permit violation, and that DEQ has never issued DEP a notice of violation identifying groundwater data as the basis of a permit exceedance. He concluded that the Public Staff has conflated these two concepts. (Tr. Vol. 21, pp. 64- 66, 74-76, 89.) The Commission notes however that witness Wells' testimony here appears inconsistent with the Company's guilty pleas in federal criminal court.

Witness Wells argued that DEP's compliance record with respect to NPDES permits has been exemplary. He stated that the Company has consistently complied with the terms of its NPDES permits over the years, and that, of well over 70,000 data points, it has had fewer than 200 permit violations, which is less than one half of 1% at all seven of its facilities in the last 10 years. Specifically with regard to Asheville, Cape Fear, H.F. Lee, Sutton, Roxboro, and Weatherspoon plants, witness Wells noted that DEP has had no more than 20 NPDES permit

[1] However, they do not apply to DEP's representations in the federal district criminal court proceeding where no settlement and where admissions of liability were made.

exceedances during this time frame.[1] He stated that, when compliance issues have arisen at individual plants, DEP has addressed those issues with regulators. (Id. at 62-63, 88-89.) Witness Wells argued further that impacts to the groundwater surrounding coal ash basins are an expected result of using unlined basins and are not the result of any mismanagement. At the time they were built – between 1956 and 1985 – unlined basins were consistent with the industry standard and considered by the EPA to be the best available control technology. (Tr. Vol. 21, p. 67.) In 1984, when the predecessor to DEQ promulgated the corrective action provisions of the 2L Standards, it acknowledged that the groundwater surrounding many existing permitted facilities was likely to exhibit some exceedances of the 2L Standards through no fault of the facility owner. (Id.) As stated above, the Commission deems this testimony instructive.

Witness Wells also disagreed with the Public Staff's suggestion that any exceedance or violation of water quality regulations, no matter how minor or how long ago, leads to the denial of cost recovery for any activity that acts to "cure" the impacts of the violation. In addition to reiterating that not all exceedances of the 2L standards amount to a violation that requires corrective action under the 2L rules, witness Wells stated that even when an exceedance requires corrective action, the groundwater rules do not treat the exceedance the same way as, for example, the Clean Water Act treats an exceedance of an NPDES permit limit. When the latter is violated, he explained, the permittee is immediately subject to an NOV and penalty, and must ensure the next discharge complies with the permit limit or risks a new NOV and escalating penalty. He stated that, in those circumstances, it would be reasonable to say that allowing the violation to continue without addressing it is mismanagement.

He contrasted this process with groundwater standards, under which an exceedance does not immediately result in an NOV and penalty. Instead, he explained, the owner/operator must report the exceedance and work with the DEQ to determine whether it was due to permitted activity, assess the extent of the exceedance, and undertake corrective action. Any newly measured exceedances do not require a further site assessment and do not result in additional or escalating penalties, but are actually expected as additional assessment prior to a requirement to take corrective action. He testified that the 2L rules' correction action provisions are designed around the idea that older facilities, built before liners were a regulatory obligation, were likely to have associated groundwater impacts, that such impacts were not the result of regulatory noncompliance, and that they should be addressed in a measured process. He concluded that compliance with this process is not mismanagement and should not be held against DEP with respect to cost recovery. (Tr. Vol. 21, pp. 79-80.)

Witness Wells further argued, persuasively in the Commission's view, that the groundwater extraction and treatment activity that DEP performed pursuant to the DEQ Settlement Agreement merely accelerated work that would have been required under CAMA in any event. (Id. at 76.) Although CAMA borrows heavily from the 2L Rules, including by incorporating the substance of its corrective action requirements, one key difference between the two laws is that CAMA's groundwater assessment and corrective action provisions are triggered by exceedances – not violations – of the 2L groundwater standards. In other words, unlike the 2L Rules, CAMA requires

[1] In reviewing witness Lucas' revised Exhibit 5, witness Wells concluded that if one were to remove the Mayo-specific events, Lucas' exhibit only indicates 4 permit exceedance violations for the other six DEP sites in the last 10 years.

utilities to perform groundwater assessment and corrective action for all identified exceedances of the 2L groundwater[1] standards regardless of whether the exceedance amounts to a violation of the applicable groundwater standard.

The Commission determines that there is insufficient evidence that the Company would have had to have engaged in any groundwater extraction and treatment activities absent the obligations imposed upon it by CAMA and/or the CCR Rule.

The Commission determines that the limitations of witness Lucas's approach are demonstrated by his inability to answer with any specificity on cross-examination: "From 1920 until 2014, with respect to ... [the] Company's ash basins in this state, what should we have done differently and when should ... [it] have done it?" (Tr. Vol. 19, p. 35.) His response essentially was that "Somewhere along the line the Company should have taken some kind of action to not contaminate groundwater." (Id. at 36.) But the kinds of actions he appears to have favored – such as lining ash ponds when this was contrary to standard practice, or creating dry coal ash basins when for the most part the Company's industry peers were sluicing coal ash into wet basin impoundments, would have cost money which would have been charged to customers, or (b) would have left the Company open to credible claims of "gold-plating," and therefore cost disallowance, which would have prevented the Company from moving forward with these suggested improvements in the first place. Witness Lucas and the Public Staff fault the Company for not taking steps that were not in accord with steps most of the industry was following, but at the same time disregarding responsibility of paying for that which they – in 20/20 hindsight – wish the Company had done.

No party disputes the reasonableness of the amount of groundwater assessment and treatment costs the Company seeks to recover in rates; rather the dispute relates to the fact the groundwater assessment and treatment costs were performed pursuant to a settlement agreement with DEQ. The testimony of witnesses Kerin and Wells demonstrates that these costs – amounting to $6,693,390 – were reasonably and prudently incurred to comply with the Company's obligations under CAMA and the CCR Rule. The Commission determines that they therefore would be recoverable in rates, as would be the $88,000 in legal fees that witness Lucas also proposed excluding as settlement agreement expenditures were it permissible to view them as standard allowable expenditures but for DEP's admissions in the federal criminal court action where DEP pled guilty to mismanagement and the timing with compliance with CAMA.

The AGO, Sierra Club, and other intervenors make similar arguments that DEP has failed to keep pace with industry standards and therefore DEP should not be allowed to recover current environmental compliance costs in rates. The Intervenors argue that DEP should have done more than just comply with the current environmental regulations at the time. However, AGO witness Wittliff testified that the definition of industry standards is compliance with law.[2] (Tr. Vol. 15,

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[1] Id.; see also N.C. Gen. Stat. § 130A-309.211. When preparing a corrective action plan, CAMA does not require the utility to describe any 2L violation and instead required only a "description of all exceedances of the groundwater quality standards, including any exceedances that the owner asserts are the result of natural background conditions." N.C. Gen. Stat. § 130A-309.211(b)(1)a (emphasis added).

[2] Upon redirect, when asked how DEP's management of ash ponds were different from industry standards, AGO witness Wittliff responded, "Well, I think there were a number of companies that were doing exactly what Duke

p. 100.) Based upon the evidence presented in this case, with the exception of the federal criminal case to which DEP pled guilty, DEP has not been found liable for violations of the law. As stated above, the Commission will not use settlement agreements to find liability. The AGO asserts that this Commission should consider all of the seeps located at its ash basin sites and deny of recovery of CCR costs. However, as stated in the criminal case which covered engineered seeps, DEQ and DEP have been in long-standing negotiations as to whether seeps are a violation of law and since 2014 whether seeps should be covered by the NPDES permit. (Wittliff Ex. 5, pp.78, 95.) (Wittliff Ex. 5.2, p. 44.) According to statements made in the criminal case, DEQ has currently not made a determination on this issue.(Wittliff Ex. 5.2, p. 44.) The Commission finds witness Wells' testimony persuasive that any past violations by DEP do not give support to the amounts of cost disallowances advocated by the Intervenors and the Public Staff in this case.

Lastly, although the record is not crystal clear as to whether DEP is seeking bottled water costs, or the amount of any bottled water costs, and no party has asked for a specific disallowance for the cost of bottled water, the Commission finds that DEP shall remove from its request any costs for bottled water, if any, that it may have agreed to provide pursuant to any lawsuit.

Garrett and Moore: Off-Site Transportation and Disposal of Coal Ash and Related Costs

The Public Staff, through witnesses Garrett and Moore, asserts that the Company acted imprudently in arranging for off-site handling of CCRs from the Sutton and Asheville Plants, and contends that disposal should have occurred at to-be-constructed on-site landfills, thereby saving primarily on the cost of off-site transportation. Garrett and Moore also expressed concern with respect to the costs the Company agreed to pay with respect to Asheville Plant coal ash, contending that it was excessive. The Public Staff recommends that a $80.5 million disallowance be applied with regard to Sutton Plant coal ash (Tr. Vol. 18, p. 180), and that a $29.3 million disallowance be applied with regard to Asheville Plant coal ash (id. at 182), for a total recommended disallowance of $109.8 million. The Commission rejects these discrete adjustments but takes these allegations into account in its mismanagement adjustments. Company witness Kerin indicates that he does not disagree that an on-site landfill was the best solution for the Sutton Plant – indeed, at Sutton, the Company built an on-site landfill, which became operational in July 2017, and is placing coal ash in that landfill today. (Tr. Vol. 20, p. 65.) The issue with respect to an on-site landfill at both sites is feasibility in light of the basin closure deadlines imposed by CAMA, and in the case of the Asheville Plant, modified by the Mountain Energy Act of 2015 ("MEA"), which requires the Company to construct a new combined cycle power plant and facilitate the shut-down of the existing Asheville coal-fired plant by January 31, 2020. (Id. at 43.)

The CAMA and, in the case of the Asheville Plant, MEA, deadlines would provide the overarching framework by which prudency must be assessed, were the Commission to ignore the contributing factors leading to CAMA and were the Commission to ignore DEP's admitted mismanagement with respect to CCR activities in its criminal court pleas, because an alternative proposed action would have to be feasible in order to truly be an alternative. 1988 DEP Rate Order, at 15. Witness Kerin's rebuttal testimony shows that Garrett and Moore's proposed alternative –

did." (Tr. Vol. 15, pp.112-13.) When asked as to whether there were any other ways besides compliance that DEP did not comply with industry standards, he responded, "I don't know ... do you have a specific thing in mind that you're wanting?" (Tr. Vol. 15, 114.) He went on to testify that the "standard, is compliance." (Tr. Vol. 15, 114.)

on-site disposal – was not feasible in the time frames available to the Company, particularly, as Kerin testified, "missing the required CAMA date was not an option . . . ." (Id. at 39.)

The Commission finds merit in DEP's assertions that the Garrett and Moore timeline for Sutton "was a 'perfect world' scenario without due consideration of the inherent uncertainty of permitting any type of landfill, especially a CCR landfill, particularly during the regulatory and political environment of 2014." (Id. at 37.) Perfection is not the standard. As an example of imperfection, Kerin points to the unexpected "environmental justice" review imposed by DEQ (Id. at 65-67), that caused a six-month delay in the issuance of the Sutton on-site landfill permit. Also, within weeks of the permit's final issuance, Hurricane Matthew blew through the area, impacting landfill construction. The Commission, however, agrees with Garrett and Moore and disagrees with witness Kerin that the moratorium prevented DEP from constructing a new CCR repository in the footprint of a preexisting repository once it had been excavated. DEP's reading of the provisions of the statute is strained and out of accord with a common sense interpretation. (Id. at 67-68.) However, DEP may have acted in response to its erroneous and overly cautious interpretation in light of the compressed time frame under which it operated.

DEP also confronted two limitations dealing with NCDEQ standards addressing dewatering and closure by removal of CCRs from surface impoundments. The standards address remediation of discharges or releases of contaminants into soil and groundwater to cleanup levels to meet the State's 2L groundwater standards.

To fully excavate CCRs for repurposing, bulk dewatering is necessary as well as interstitial dewatering from submerged ash. DEQ completed applicable regulatory requirements in 2015. For Sutton, the requirements were specifically detailed in the amended and approved NPDES permit in December 2015. As these dewatering requirements were not defined by DEQ in 2014 or 2015, a viable option for converting the existing CCR impoundment at Sutton to a new landfill did not exist then.

DEQ's cleanliness requirements set forth in its "Coal Combustion Residuals Surface Impoundment Closure Guidelines for Protection of Groundwater" were not completed until November 2016. DEP could not convert the Sutton impoundment to a new CCR landfill in 2014 or 2015 until the guidelines had been established. Therefore, compliance with CAMA deadlines through reliance solely on an on-site landfill was not possible. (Tr. Vol. 20, pp. 35-37.)

In addition, while "perfect world" scenarios may appear appropriate in an after- the-fact analysis, once CAMA became law, prudent planning required the Company to meet "real world" difficulties as and when they arose, to ensure that the legislatively fixed August 1, 2019 deadline would be met. To do so, the Company devised for Sutton a two-part plan that included both the construction of an on-site landfill and off-site disposal of some portion of the coal ash – approximately two million tons, of the 6.6 million tons of coal ash in the Sutton coal ash basins. (Id. at 39.) Had the Company not arranged for off-site disposal, it would have been required to transport the 6.6 million tons of coal ash from the coal ash basins to the new on-site landfill in the 25-month period from the issuance of the landfill's operating permit (July 7, 2017) to CAMA's August 1, 2019 closure deadline. In the Commission's view, this was an unreasonable task. (Id. at 40.) The Company's Sutton plan, therefore, in light of the CAMA deadlines and the delays in obtaining permits, does not rise to the level of imprudency the standard the Commission deems required. Therefore, discrete cost disallowances are not approved.

The Commission determines that similar considerations come into play when assessing the prudence of the Company's decision to transport Asheville Plant CCRs offsite once CAMA became law. (Id. at 42.) The MEA, while extending the closure deadline to August 1, 2022, required construction of a new combined cycle plant. (Id. at 43.) The new plant must be built on the site of one of the Asheville Plant's basins. This meant that that basin had to be emptied of coal ash. That, along with the need for an extensive construction laydown area necessary to allow efficient construction of the new plant, left no space at the Asheville Plant site in which to build an on-site landfill. As witness Kerin put it, the MEA "effectively made construction of a new on-site CCR landfill technically infeasible given the short time period to replace the coal-fired generation by 2020, and close the coal ash basins by 2022." (Id. at 43.)

In the 1988 DEP Rate Order, this Commission stressed the importance of carefully examining the Company's explanations of the decisions it made, as of the time they were made, and emphasized that the credibility of the decision-makers, particularly in juxtaposition to after-the-fact analyses, presented by Intervenor-retained consultants. See, e.g., 1988 DEP Rate Order, at 29. The Commission does not question the bona fides or expertise of Garrett and Moore; indeed, witness Kerin notes (and appreciates) that they "conducted a thorough and principled analysis" of the Company's CAMA/CCR Rule compliance costs, and that he agreed with "the majority of their conclusions." (Tr. Vol. 20, p. 56.) The Commission determines, however, that witness Kerin has "lived" this project since its inception (Id. at 32), and relies upon his testimony regarding the decisions made, and determines that the Garret and Moore adjustments, other than to the extent addressed indirectly in the Commission's management penalty, will not be adopted.

Witnesses Garrett and Moore also asserted that that DEP exclusively should have utilized the Cliffside landfill in lieu of the Homer, Georgia landfill due to closer proximity and the lower cost of the Cliffside landfill. (Tr. Vol. 18, pp. 182-83.) However, in live testimony at the hearing, witnesses Garrett and Moore accepted that moving the required coal ash from Asheville to Cliffside, as they testified should have been done, would have amounted to 30,162 truckloads, 3,619,440 miles of driving, equal to about 145 trips around the earth. (Id. at 198-99.) They also agreed that for a six-month period of time this would require moving 4,292 tons of coal ash per day, by 232 trucks per day, which means one truck leaving the site every two minutes. (Id. at 199.)

Witness Kerin, noting that Garrett and Moore had not accounted for over 500,000 tons of coal in their analysis, demonstrated the infeasibility of their approach. He indicated on cross-examination by counsel for the Public Staff that the Company was already sending 195,000 tons of coal ash to Cliffside at that time, and that the additional 558,000 tons proposed by witnesses Garrett and Moore would have resulted in about 40,000 loads, "or loading a truck every minute and a half, loading, moving, scales, washing, getting it through the site and getting it on the highway. Virtually impossibleat that site, if you have ever been to the Asheville site where the '82 basin is, to move that many trucks through that site and out of that basin in a minute and half per truck." (Tr. Vol. 20, p. 113.) The Commission agrees with DEP that infeasible options do not support a finding of discrete adjustments for imprudence. 1988 DEP Rate Order, at 15. The Commission determines that witness Kerin's testimony demonstrates that the Company's actions and real-time decisions regarding the Ashville site were in fact reasonable and prudent in the context of the requirement of CAMA and the MEA, and that the costs, in the context of analysis the witnesses undertook, were in fact prudently incurred. As such, no discrete disallowance is approved with the exception of the increased contracted disposal costs with Waste Management, Inc. of $9.5 million. The Company essentially agreed that this adjustment for contractual coal ash moving expense was appropriate and the Commission agrees.

Conclusion with respect to January 1, 2015 – August 31, 2017 Costs

The Commission finds that the costs are known and measurable, when viewed in isolation and without regard to the broader context of DEP's admission of criminal negligence in the management of its CCR activities, and the cost increases arising from the CAMA schedule, the costs, with noted exceptions, were reasonably and prudently incurred, and are used and useful in the provision of service to customers. But for the Company's admissions of mismanagement and the extent such conceded mismanagement was a contributing factor resulting in the enactment of CAMA, they should be recoverable from customers.

But for the management penalty discussed below, the Commission deems the Company's proposal, which submits that the amortization period should be five years, would be reasonable and appropriate. The five-year period suggested by theCompany is identical to the period over which Dominion's already-incurred coal ash basin closure costs were amortized in the 2016 DNCP Rate Case. It further had the virtue, when originally proposed, of being identical to the five-year period over which the Company proposed to return to customers excess deferred taxes resulting from the change in North Carolina's income tax rate (*see* Tr. Vol. 6, p. 129), although that time period was later reduced as part of the Partial Settlement with the Public Staff to four years. While the amount of the excess deferred tax regulatory liability (approximately $150 million; *see* Peedin Revised Exhibit 2, Schedule 1, Line 1) is less than the coal ash basin closure cost deferred balance that the Company seeks recovery of in this case (approximately $242 million), both are substantial. It would be reasonable to use similar amortization periods for both the deferred tax regulatory liability returned to customers (with a return) and the coal ash basin closure regulatory asset collected from customers (also with a return).

In summary, the Commission determines that but for admitted mismanagement and its being a contributing factor to CAMA, its coal ash basin closure costs actually incurred over the period from January 1, 2015 through August 31, 2017 are (a) known and measurable, (b) reasonable and prudent, and (c) used and useful, and, as such, that it is entitled to recover those costs in rates. DEP has further shown that its proposal that these costs be amortized over five years, with a return on the unamortized balance, would have been reasonable.

The Public Staff's 50/50 "Equitable Sharing" Concept

Witnesses Lucas and Maness, for the Public Staff, propose a 50% disallowance of the Company's already-incurred coal ash basin closure costs through what Maness terms a 50/50 "equitable sharing" arrangement between shareholders and customers. (Tr. Vol. 18, p. 309.) He implements this sharing concept with two steps. First, he removes the unamortized coal ash basin closure costs from rate base, thereby eliminating any return on that unamortized balance. (Id.) The second step is to choose an amortization period that will result in the desired level of "sharing." (Id. at 10.) As the Public Staff's desired level is 50/50, mathematically that results in a 26-year amortization period at the rate of return the Company and the Public Staff agreed, subject to the Commission's approval, was appropriate in this case. (Id. at 344-45.) As witness Maness acknowledged, with a different rate of return, "the number of years might be different to reach the 50 percent mark." (Tr. Vol. 19, p. 59.)

The Commission agrees with DEP that this adjustment is not based on an applicable standard. The Public Staff chose this number, then adjusted the mechanism to achieve that level of disallowance. The Public Staff provides insufficient justification for the 50/50 as opposed to a 60/40, or 80/20. Witness Mannes indicates merely that it "was the judgment of the Public Staff ... that 50 percent was a reasonable percentage." (Id.)

A "determining principle" or prudency standard is missing from the Public Staff's 50/50 "equitable sharing" proposal. See Tate Terrace Realty Investors, Inc. v. Currituck Cty., 127 N.C. App. 212, 222-23, 488 S.E.2d 845, 851-52 (1997). As such, were the Commission to adopt it, the Commission very well could be found to be acting arbitrarily and capriciously, and subject itself to reversal. An illustrative case is Sanchez v. Town of Beaufort, 211 N.C. App. 574, 710 S.E.2d 350 disc. review denied, 365 N.C. 349, 715 S.E.2d 152 (2011)

Ultimately, the Public Staff, through Witness Maness, indicates that it is "up to the Commission's discretion to determine what [the] sharing should be." (Tr. Vol. 19, p. 69.) Even if the equitable sharing mechanism were without legal impediments, the Commission chooses in the exercise of its discretion not to adopt this recommendation but instead on an alternative remedy addressed below. The Public Staff bases its proposal on two principles: first, the Company's alleged past failures, as detailed in the testimony of Public Staff witness Lucas, to prevent environmental contamination from its coal ash basins, and, second, an asserted "history of approval of sharing of extremely large costs that do not result in any new generation of electricity for customers." (Tr. Vol. 18, p. 309.)

As to the first asserted predicate, the parties dispute the existence of failures. The Commission addresses Wells' testimony, above, but whether or not the Company were guilty of some sort of violation appears not to be material to the Public Staff's 50/50 sharing proposal. Witness Maness admitted, in response to questions from the Chairman, that all of these alleged acts or failures to act occurred in the past. (Tr. Vol. 19, pp. 60-61.) Witness Maness's response to the Chairman's questions leads to the true heart of the matter – the Public Staff's position, simply stated, is that it does not matter if the Company's actions in incurring the CCR Rule and CAMA compliance costs were prudent – the Public Staff's 50/50 equitable sharing proposal would still apply. As Maness testified, "[E]ven if you left out specific acts or omissions of the Company and assumed everything was prudent, aboveboard" (Tr. Vol. 19, p. 61), the Public Staff would (at least "likely") still recommend the 50/50 equitable sharing proposal. (Id.) Accordingly, the real rationale for the Public Staff's proposal appears to be witness Maness's second predicate: the proposition that the Commission has a "history of approval of sharing of extremely large costs that do not result in any new generation of electricity for customers." (Tr. Vol. 18, p. 309.)

According to witness Wright, there is "no provision of Chapter 62 requiring different treatment for 'extremely large costs'" (Tr. Vol. 20, p. 141), and, in any event, witness Wright detailed any number of "extremely large cost" items not associated with new generation for which cost recovery is routinely allowed. (Id.) This is yet another example of the arbitrariness inherent in the Public Staff's sharing proposal. While the Commission in the past has made decisions to avoid "rate shock," that equitable principle does not apply here in the context of the recommended cost disallowances.

On another level, it appears that witness Maness is saying that this rationale for the sharing proposal is grounded in the Public Staff's view of the discretion available to the Commission. He states first that pursuant to G.S. 62-133(b)(1), and with the exception of construction work in progress under certain circumstances, "the only costs that the Commission is required to include in rate base are ... the 'reasonable original cost of the public utility's property used and useful, or to be used and useful within a reasonable time after the test period ....'" (Tr. Vol. 18, p. 310.) He indicates that he is advised by counsel that "beyond these requirements what is and what is not in rate base is fully within the Commission's discretion to decide, as long as the rates set thereby are fair and reasonable to both the utility and the consumers." (Id.) The Commission determines that the Public Staff's view of the Commission's discretion is overly broad, however, and not supported with the cited Supreme Court precedent. Likewise, to the extent the Public Staff is correct in its arguments that the Commission has the discretion to accept the Public Staff's equitable sharing remedy, the Commission declines to do so in favor of an alternative remedy addressed below.

As expressed through witness Maness's testimony, the Public Staff looks to the Commission's Order Granting Partial Increase in Rates and Charges in Docket No. E-2, Sub 526 (Aug. 27, 1987) (the 1987 DEP Rate Order) and its affirmance by the Supreme Court in Thornburg I, 325 N.C. 463, 385 S.E.2d 451 (1989) as precedent for its 50/50 equitable sharing concept. The Commission determines that the more compelling precedents are the 1988 DEP Rate Order and the Commission's Order Denying Motions for Reconsideration in the 1988 DEP Rate Case (Docket No. E-2, Sub 537) (1988 DEP Reconsideration Order), and the Supreme Court's reversal in part of those Orders in Thornburg II, 325 N.C. 484, 385 S.E.2d 463 (1989). The principal issue in the 1987 DEP Rate Case/Thornburg I was whether the Company could recover in rates any portion of the costs associated with the abandoned Units 2, 3, and 4 of the Shearon Harris nuclear plant. The Commission had previously decided that the Company could amortize the unrecovered costs associated with these abandoned units over a ten-year period, but that "no ratemaking treatment should be allowed which would have the effect of allowing ... [the Company] to earn a return on the unamortized balance." 1987 DEP Rate Order, at 61. Over the objections of the AGO, the Commission decided to continue to follow that process in the 1987 case – it allowed amortization of abandonment costs over a ten-year period as an operating expense under G.S. 62-133(b)(3) and 62-133(c), but no return authorized on the unamortized balance. The North Carolina Supreme Court, in a passage extensively quoted in witness Maness's testimony (see Tr. Vol. 18, pp. 311-12), affirmed the Commission's decision, holding that G.S. 62-133(b)(3) and 62-133(c) were elastic enough to include abandonment costs as utility "expense," and that G.S.. 62-133(d), which allows the Commission to factor in "all other material facts of record that will enable it to determine what are just and reasonable rates," also provided support for the Commission's decision. The Court further held that as a matter of policy a return of, but not a return on, the abandonment costs was appropriate. Thornburg I, 325 N.C. at 476-81, 385 S.E.2d at 458-61.

In Thornburg I, the Court held specifically that the Commission's recovery but no return decision was "within the Commission's discretion" and would not be disturbed. Id. at 481. That decision effected a "sharing" between the Company's shareholders, on the one hand, and its customers, on the other – shareholders received a return of the costs, but no return on the costs. It is based upon this holding that the Public Staff, through witness Maness's testimony, contends that "reasonable rates can include a sharing between ratepayers and investors with regard to plant cancellation costs" (Tr. Vol. 18, p. 311), and that the Commission possesses discretion to implement this sharing.

There are, however, significant distinctions between the 1987 DEP Rate Case/Thornburg I and the present case. First and foremost, this case does not involve "abandoned plant" or cancellation costs. Rather, it involves "reasonable and prudent" and "used and useful" expenditures by the Company, similar to the Commission's determination in the 2016 DNCP Rate Order. As such, the authority the Public Staff relies upon to support its "equitable sharing" concept does not support the exercise of discretion as the Public Staff maintains. This can be seen when examining other prior orders of this Commission and the correct Thornburg case: the 1988 DEP Rate Order, the 1988 DEP Reconsideration Order, and Thornburg II.

In the 1988 DEP Rate Case, the principal issue for decision was the reasonableness and prudence of the costs of constructing and placing into service Unit 1 of the Shearon Harris nuclear plant. The Commission found that for the most part, Harris Unit 1 costs were reasonable and prudent, and that part of the 1988 DEP Rate Order was upheld by the Supreme Court. 325 N.C. at 489, 385 S.E.2d at 465-66 (finding "no error" in that part of the Commission's Order). However, a part – $570 million- worth of the costs the Commission considered were incurred in connection with facilities to be shared with Units 2, 3, and 4, units that the Company had abandoned. The Commission found that while these costs were prudently incurred, they should be shared between the Company's customers and its shareholders. The Commission found that approximately $180 million of those costs were properly classified as "abandonment" costs and should be borne by shareholders. 1988 DEP Rate Order, at 112-14. The remaining $390 million were left in rate base.

Responding to the Public Staff's request that the Commission reconsider this decision and remove the entire $570 million from rate base on the grounds that all of it related to abandoned plant, the Commission reaffirmed its decision in the 1988 DEP Reconsideration Order and provided additional explanation for its ruling. It stated (1988 DEP Reconsideration Order, at 2-3) that the Public Staff's request that the full $570 million for the common facilities be treated as abandonment costs was based upon a "misunderstanding" of the 1988 DEP Rate Order and the Commission's objective in splitting this $570 million item into $390 million of rate base and $180 million of cancellation costs. The Commission did not (it says in the 1988 DEP Reconsideration Order) intend to treat the "excess common facilities" as abandoned plant; rather, it effected an "equitable sharing" (emphasis added) of the $570 million between customers and shareholders. The Commission reiterated that the Company's choice of the cluster design – which engendered the shared facilities – was reasonable and prudent, and that, except as specifically indicated in the 1988 DEP Rate Order, the costs of the Shearon Harris plant were "reasonable and prudently incurred." Thus, the Commission found, the $570 million at issue was also reasonably and prudently incurred.

Nevertheless, the Commission held (Id. at 4-5) that it was appropriate to share the $570 million at issue, and it indicated that it arrived at the allocation (essentially one- third to cancellation costs and two-thirds to rate base) on its own and adopted it "for reasons of fairness and equity." It held that it continued "to believe that a reasonable and equitable apportionment of the burden and risks associated with ... [the Company's] prudent investment in common facilities is appropriate." It stated further that its assignment of $180 million as the value of the Company's prudent investment in common facilities to be treated as cancellation costs for ratemaking purposes was an appropriate exercise of its "regulatory discretion."

The North Carolina Supreme Court disagreed. The Court held that the Commission did not possess the discretionary power to effectuate its "equitable sharing" decision. Rather, the facilities were either "used and useful," and therefore in rate base, or they were not. The Court looked to the Commission's finding that the facilities in question were "excess common facilities," and held that "excess" facilities were not "used and useful" as a matter of law. 325 N.C. at 495, 385 S.E.2d at 469. Accordingly, looking to the correct Commission and Supreme Court precedent, these determinations are insufficient support for the Public Staff's "equitable sharing" concept.

In addition to the costs of abandoned nuclear construction, witness Maness contended that there is precedent for approval for sharing of extremely large costs that do not result in any new generation of electricity for customers. He asserted that sharing between ratepayers and shareholders has also been approved for environmental cleanup of manufactured gas plant (MGP) facilities. (Id. at 309-10, 343-44.) In rebuttal, witness Wright testified that the Commission's treatment of environmental cleanup of manufactured gas plants does not support the Public Staff's proposed cost sharing, and referred to his direct testimony that MNG [MGP] plant costs differ from coal ash disposal costs, both in terms of the time that elapsed between the actual usage of the facility and the environmental-related cost recovery, and in terms of ownership. In addition, he noted that MNG [MGP] facilities, like abandoned nuclear plants, were found not to be used and useful. He noted further that there is no need to rely on a 23-year-old cost recovery example from a different industry, dealing with assets last used more than 70 years ago, when the best example of the Commission's treatment of coal ash disposal costs can be found in the Dominion case that was decided one year ago. (Tr. Vol. 20, pp. 138-40, 173.) The Commission also notes that the North Carolina Commission was in the minority among states on the way that it handled MGP costs, ie, the "sharing of costs." The majority of states granted full recovery of MGP costs. See Recovery by Utilities of Expenditures on Manufactured Gas Plant Claims: Recent Developments Regarding Insurance Coverage and Rate Relief, Nicholas Fels, William Skinner and Saul Goodman, p. 44 (August 1, 1996). The Commission finds that the Commission's decision in Docket No. G-5, Sub 327, Public Service Co. of North Carolina, 156 PUR 4th 384 (October 7, 1994), is distinguishable from the CCR remediation costs at issue in this case and moreover not precedent the Commission chooses to follow to provide for sharing in the present case.

The issue that remains is whether the already-incurred costs expended by the Company in connection with its CCR Rule/CAMA compliance obligations are "used and useful" and "prudent and reasonable." DEP argues that the Commission has already decided this issue, in the 2016 DNCP Rate Order, where it held that costs expended for the identical purpose were "used and useful." 2016 DNCP Rate Order, at 60-62, and that were the Commission to decide differently in this case, the Commission would be acting arbitrarily and capriciously. DEP cites Gregory v.

County of Harnett, 128 N.C. App. 161, 164-65, 493 S.E.2d 786, at 788 (1997) (County Commission, which approved a zoning application restricting mobile home development three days after rejecting an almost identical application, acted arbitrarily and capriciously). [1] The Commission disagrees. While the Commission's Order here is consistent with the logic of its DNCP Order, it disagrees with DEP that it is bound to follow it. The Commission expressly stated that its CCR determinations in the DNCP Order were non-precedential. Moreover, this is a ratemaking decision in which the Commission exercises its legislative authority.[2] Its past decisions are neither binding, res judicata[3] nor stare decisis.[4]

In its cross-examination questions (*see, e.g.*, Tr. Vol. 14, pp. 236-37), the Public Staff suggests that if the Company truly thought the coal ash basin closure costs were "used and useful" it should have put them directly into rate base as opposed to deferred into a regulatory asset via ARO accounting. Witness Maness stated such in his responses to the Chairman's questions, indicating that he had struggled with the issue but had not "found anything direct yet" in the accounting literature. (Tr. Vol. 19, p. 66.) The accounting issue, as far as witness Maness is concerned, is how the Company's coal ash basin closure costs could be classified as "plant," and therefore eligible to be included in rate base, when they are actually accounted for in an ARO, which deals with retirement costs. (Id.) witness Maness also indicates that the Company "chose[] not to propose to include these type of costs ... as utility plant and service." (Id. at 67.)

The Commission disagrees with the Public Staff's characterization. First, the Company did put coal ash basin closure costs directly into rate base. See Bateman Supplemental Ex. 1, p. 54. The costs were included in the Working Capital section of rate base (Id. at 53), and no party has taken the position that their inclusion therein was inappropriate.[5]

The AGO makes a related argument in its post-hearing Brief. The AGO argues that DEP failed to request in advance permission to create a deferred account. Contrary to witness Maness's indication that the Company had any "choice" in the matter, and the AGO's argument, upon the passage of CAMA and the promulgation of the CCR Rule, the Company was required by GAAP to establish an ARO. The accounting guidance (ASC 410-20-15-2) states that it applies to "Legal

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[1] While certain Intervenors argue that Dominion's situation is different from the Company's in that Dominion had not committed environmental "violations," this purported distinction is of no moment. Dominion in fact has been the subject of regulatory scrutiny with respect to its Chesapeake Plant, and has been the target of lawsuits brought by environmental advocacy organizations in connection therewith. (Tr. Vol. 20, pp. 135-37, 171-72, 189.)

[2] State ex rel. Utils. Comm'n v. Edmisten, 294 N.C. 598, 242 S.E. 2d (1978) (ratemaking activities of the Utilities Commission are a legislative function).

[3] Id. (only specific questions actually heard and finally determined by the Utilities Commission in its judicial character are res judicata).

[4] State ex. Rel., Utils. Comm'n v. Carolina Utility Customers Ass'n, Inc., 348 N.C. 452, 500 S.E. 2d 693 (1998) (Utilities Commission orders in rate cases are not within the doctrine of stare decisis).

[5] While witness Maness removed the Company's coal ash basin closure costs from Working Capital section of rate base, he did so not because of any quarrel with their inclusion therein, but in order to give effect to the Public Staff's 50/50 "equitable sharing" proposal. (*See* Tr. Vol. 18, p.309.)

obligations associated with the retirement of a tangible long-lived asset," and "legal obligation" is defined (ASC 410-20-20) as an "obligation that a party is required to settle as a result of an existing or enacted law ...." (Emphasis added). Once it became clear that the new laws and regulations governing coal ash would require closure of the Company's existing coal ash basins, GAAP required that an ARO be established, and the Company had no choice in the matter. As the Public Staff and the Commission have noted previously, "Statements of the FASB are officially recognized by the Securities and Exchange Commission (SEC) as authoritative with regard to GAAP in the United States, and the requirements included in those Statements are essentially mandatory for any publicly traded entity." See Order Granting in Part and Denying in Part Request for Deferral Accounting, Docket E-2, Sub 826 (April 4, 2003), at 13. Moreover, DEP notified the Commission of its establishment of the ARO.

As a matter of law, it is not necessary that something be classified as "plant" in order to be properly included in rate base. Rather, the issue is the source of the funds. In State ex rel. Utils. Comm'n v. Virginia Elec. & Power Co., 285 N.C. 398, 206 S.E.2d 283 (1974) (VEPCO), for example, the Supreme Court held that working capital (which is not "plant") could be included in rate base, so long as it was provided by the utility:

> Like any other business, a public utility must at all times have on hand a reasonable amount of materials and supplies and a reasonable amount of funds for the payment of its expenses of operation. While Chapter 62 of the General Statutes makes no reference to working capital, as such, the utility's own funds reasonably invested in such materials and supplies and its cash funds reasonably so held for payment of operating expenses, as they become payable, fall within the meaning of the term "property used and useful in providing the service"... and are a proper addition to the rate base on which the utility must be permitted to earn a fair rate of return.
>
> Conversely, the utility is not entitled to include in its rate base funds which it has not provided but which it has been permitted to collect from its customers for the purpose of paying expenses at some future time and which it actually uses as working capital in the meantime.

285 N.C. at 414-15, 206 S.E.2d at 295-96. As the Company appropriately accounted for coal ash basin closure costs in the working capital section of rate base, and as these funds were investor-furnished, not customer- furnished, VEPCO holds that they are "used and useful" within the meaning of G.S. 62-133(b)(1) in the provision of service. As such, the Company is entitled to earn a return on those funds over the period in which the costs are amortized.[1]

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[1] Even if for some reason some portion of the Company's already-incurred coal ash basin closure costs might not be classified as "used and useful," that does not mean that they are not recoverable or that the Company may not earn a return on them. In Dominion's 2012 Rate Case, the utility sought to recover over a three-year amortization period the unrecovered costs associated with one of early-retired coal-fired plants (North Branch), with DNCP earning a return on the unamortized balance. The Public Staff agreed that the costs of the retired plant, although not placed into rate base, should be recovered over an amortization period, and that DNCP should earn a return on the unamortized balance, but advocated for a ten-year rather than three-year, amortization period. The Public Staff argued that, as was the case in Thornburg I, the Commission had authority to treat these unrecovered costs in this fashion within the discretionary authority granted the Commission through G.S. 62-133(c) and 62-133(d). See Order Granting General Rate Increase, Docket No. E-22, Sub 479 (Dec. 21, 2012), at 36. The Commission agreed, and implemented

A concrete illustration highlights this issue more clearly. Take, for example, the new coal ash landfill that the Company constructed at the Sutton plant. The landfill "went into service in July ... [2017], and ... [the Company is] placing ash in the landfill today." (Tr. Vol. 20, p. 65.) The Public Staff, through its consultants Garrett and Moore, has no quarrel with the construction of the landfill or its cost, except for the liner chosen, and agrees that the funds expended in constructing this landfill were reasonable and prudent. The Public Staff maintains however that the landfill should have been constructed sooner and so has proposed a disallowance of the cost of off-site transportation and disposal of coal ash from the Sutton plant. The landfill is "used and useful." It consists of liners, for example, that are capital items with service lives in excess of one year. It stores coal ash which itself is a byproduct of electricity generation, and is required to be stored in a landfill by the CCR Rule and/or CAMA. Yet the Public Staff is also saying that because the costs of construction are accounted for in an ARO -- as required by GAAP, to which the Company is subject – they are somehow not "used and useful." The Commission rejects this label-driven classification.

Witness Maness testified that whether the CCR remediation costs were used and useful was not a determinative factor in justifying its equitable sharing remedy. (Tr. Vol. 19, pp. 64-67) He testified that where capital costs such as constructing lined repositories or caps over existing repositories are accounted for as an ARO, accounting conventions for ARO's control. As such, in addition to its determinations above, the Commission determines that the debate between the parties on this issue is not one the Commission is required to resolve. Costs placed in an ARO account are eligible for deferral and amortization and for earning on the unamortized balance. As such, even if the remediation costs are ARO expenditures, they are eligible for ratemaking treatment as though they are used and useful assets.

Conclusion as to Non-Cost Specific Disallowance Proposals

The disallowance methodologies proposed by the AG, CUCA, and the Public Staff discussed above fail because they fail to comply with the Commission's prudence framework, established in the 1988 DEP Rate Order and upheld by the Supreme Court in Thornburg II. They avoid the detailed analysis that an appropriate framework requires. Public Staff witness Lucas, for example, noted that the Public Staff advocates "equitable sharing" because of the difficulties and complicating factors attendant upon detailed cost analysis (Tr. Vol. 18, pp. 59-61), and he reiterated his contention on cross-examination, noting that "There is nothing wrong with a simple solution." (Tr. Vol. 19, p. 22.) However, the Commission's prudence framework requires a detailed and cost-specific analysis to the extent the Commission resolves the CCR disputes on the basis of discrete prudence assessments alone. The Company's costs are presumed reasonable and prudent unless challenged, and the challenges presented must (1) identify specific and discrete instances of imprudence; (2) demonstrate the existence of prudent alternatives; and (3) quantify the effects by

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the Public Staff's suggestion. *Id.* at 37. Accordingly, the Commission, in the event that it is later determined that some portion of the Company's already-incurred coal ash basin closure expense is not "used and useful" within the meaning of G.S. 62-133(b)(1), may nevertheless allow that portion of those costs to be amortized in the same manner as the portion of "used and useful" costs, with the Company earning a return on the unamortized balance. For the reasons stated herein, were the "used and useful" decision the Commission has reached be found to be in error, the Commission would nevertheless approve the Company's cost recovery proposal in all respects, and would exercise its discretion to achieve that result.

calculating imprudently incurred costs. 1988 DEP Rate Order, at 15. The methodologies proposed do not do that, and the Commission determines not to accept them.

In addition, were the Commission to disallow reasonably incurred and prudent costs in the magnitude suggested by the Public Staff (50% disallowance) through adjustments advocated, much less the higher or unspecified disallowances suggested by CUCA and the AGO, the result when translated into rates would be unjust and unreasonable, while the Commission's charge is to fix rates that are, to the contrary, just and reasonable. G.S. 62-131(a).

Company witness De May, asked his view on the likely reaction of the investment community to a Commission decision accepting the Public Staff's 50/50 "equitable sharing" proposal, expressed concern. He indicated, first, that "coal ash, to the financial community, doesn't look a whole lot different ... to the other environmental regulations that have come to this industry over the many decades." (Tr. Vol. 8, p. 434.) He continued:

> Just looking at the rating agency reports and the analysts' reports, you could see that everyone is just sitting, waiting to see what the impact ... [of] coal ash recovery will be to our company. And I think there is an expectation, as one analyst from Guggenheim [put it] ... that recovering environmentally-related investments coupled with ... our track record on getting environmental cost recovery, as well as precedent in doing so by this Commission [that] gives the [financial] community some confidence that we are going to get through this just like we have gotten through the Clean Air Act and through all of the clean smokestack legislation. All of these things have come to our industry, and come to our company, and we have dealt with them. This is no different.

(Id. at 434-35.) De May concluded, however: "[I]f the Public Staff position on coal ash were to be imposed upon our company, I think you would be looking at a totally new day in the way investors look at our company ...." (Id. at 435.)

As Company witness Hevert notes, "[W]e cannot underestimate the importance to investors of a consistent and constructive regulatory environment. ... In fact, 50.00 percent of the factors that Moody's Investor Service considers in determining credit ratings are related to the nature of regulation. From that perspective, it is clear Staff's recommendation implies a level of risk that would negatively affect both debt and equity investors and would increase the cost of capital to customers." (Tr. Vol. 8, p. 167.) The Commission acknowledges the danger and repercussions of changed investor perceptions of the regulatory environment. As it stated in the Company's 2013 rate case:

> Moreover, the Commission in establishing a rate of return on equity and other cost of service determinations is mindful that should it set the rate of return on equity too low, the impact on long term rates may be harmful to ratepayers. The utilities the Commission regulates compete in a market to raise capital. Financial analysts, rating agencies, and investors themselves scrutinize with great care the regulatory environment and decisions in which these utilities operate. The regulatory environment includes the utilities commissions, consumer advocates, the state

> legislature, the executive branch and the appellate courts. When regulatory risk is high, the cost of capital goes up.

2013 DEP Rate Order at 37 (emphasis added).

While the Commission's observation regarding the regulatory environment was specifically made in the context of its discussion of return on equity, the observation is apt in the cost recovery context as well. The North Carolina Supreme Court, rejecting in Thornburg I the AGO's argument that no abandoned plant/cancellation costs be charged to customers, observed that the AGO's position:

> [T]hough initially placing the entire cost upon the shareholders, may actually in the long term be less favorable to the ratepayers .... As one commentator has noted:
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>> [I]n the long run, consumers end up paying—and paying twice— because what they gain by "saving" cancellation costs, they lose in higher rates of return as well as in diminished utility stature in the capital markets.
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> Olsen, Statutes Prohibiting Cost Recovery for Cancelled Nuclear Power Plants: Constitutional? Pro-Consumer?, 28 Wash.U.J.Urb. & Contemp.L. 345, 377 (1985).

325 N.C. at 480-81, 385 S.E.2d at 460-61.

The Commission has considered this evidence and these arguments when framing its resolution in this matter. The Commission has further considered the AGO's arguments regarding DEP's criminal convictions when assessing its management penalty.

Sierra Club witness Quarles testified that continued storage of coal ash at Roxboro and Mayo poses significant environmental risks, and concluded that closure in place at these basins would allow continued contamination of downgradient groundwater and violate the technical standards of the CCR Rule. Witness Quarles further testified that removal of coal ash from DEP's CCR basins would reduce the concentrations and extent of this contamination. (Tr. Vol. 13, pp. 132-73; 175-77.) However, he admitted on cross- examination by Public Staff counsel that excavation and moving the ash at Mayo and Roxboro to lined landfills would increase the cost for closure. (Id. at 180.) Further, witness Quarles made no effort to quantify the economic impact of his recommendations. The Commission is not persuaded by the evidence presented by witness Quarles that the Commission is in a position at this time to determine whether DEP's closure plans at Roxboro and Mayo are reasonable and prudent. As a result, the Commission declines at this time to direct DEP to pursue any particular closure plans at Roxboro and Mayo.

The Sierra Club further asserts that all of the coal ash closure costs are the result of unlawful discharges and are not recoverable pursuant to G.S. 62-133.13. The Commission rejects the Sierra Club's reading of G.S. 133.13. The costs being incurred are not resulting from an unlawful discharge as defined by the statute, which is a discharge that results in a violation of State or federal surface water quality standards. Rather, DEP is incurring the costs to comply with the federal CCR rule and CAMA.

NC WARN has argued that DEP should not make a profit from selling coal ash from its existing basins. There is no evidence in the record that DEP is profiting from the sale of coal ash. Rather, any sale of coal ash merely reduced the remediation costs that DEP otherwise incurred and any payments made for its beneficial reuse offset those remediation costs.

The Commission's Cost of Service Penalty

The costs DEP has incurred through the end of the test year as adjusted in coal ash remediation tasks have been substantial, and the Company will continue on an annual basis to incur a substantial level of costs through approximately 2028. The vast majority of these costs would have been incurred irrespective of management inefficiency in order to comply with EPA CCR requirements. When DEP initially constructed coal ash impoundments and transported CCRs to them many decades ago, it did so in accord with the prevailing industry practices at the time, especially in this part of the country. In part and over time this was in response to environmental regulations requiring the removal of pollutants such as CCRs from the coal plant smokestacks to reduce air pollution.

Over time, the EPA and other environmental regulators have scrutinized the impact of CCRs in unlined repositories on surface and ground water and have assessed the extent to which harmful constituents in CCRs exceed those naturally occurring in the environment and their impact on human health. One long-lasting debate before EPA addressed the extent to which CCRs should be classified as hazardous waste under RCRA, a debate only recently resolved. Had EPA classified CCRs as a hazardous waste, economic reuse in all likelihood would have become an impossibility.

Another area of scrutiny has been the appropriate need for and method of remediation with respect to closing and potentially moving CCRs from unlined impoundments.

Many of the criticisms of DEP's CCR remediation practices raised in this case, before the federal district court in the criminal proceeding and before other courts and administrative agencies, address issues such as seeps from impoundment dikes, failure to adequately maintain risers, improper maintenance of dikes, lax reporting, exceedances and NPDES violations with respect to surface water discharges. The primary and ultimate remediation however is dewatering and excavation of and transportation from existing unlined impoundments and construction of new lined impoundments or, for older discontinued impoundments that qualify, caps preventing rainwater intrusion. This is where the vast majority of the billions of dollars of CCR remediation costs must be spent. This ultimate remediation step is necessary to prevent leachate from infiltrating groundwater from the bottom of unlined basins, but would have been required irrespective of the harms that constitute other alleged mismanagement. In addition, this remediation process cures other less pervasive environmental and health threats.

Intervenors fault DEP for failure to undertake this remediation process years earlier before being required to do so.[1] Had DEP acted in compliance with these assertions, it would have

[1] The Public Staff, however, was unable to classify DEP's actions or inactions as imprudence. Public Staff witness Lucas testified:

incurred costs its consumers would have been responsible for then. So from a ratemaking perspective, this Commission's concern, the question of when the remediation should have taken place, now or in the future or twenty years ago, is not determinative of whether the costs of the remediation should be recovered through rates and to what extent. Intervenors are unable to show when DEP should have acted differently in the past or what the increased costs would have been then. [1] Indeed, whenever undertaken, the costs would have been site specific, and establishing a past cost in this case would be a near impossibility. As DEP would have been required to undertake the remediation at issue in 2015 through 2017, irrespective of other improper actions of which it has been accused and for which it pled guilty to and was sentenced for in the criminal proceeding, any disallowance in this case must be made within the context of these facts.

DEP in the past contemplated a future requirement to close unlined impoundments. While it was reasonable and appropriate to anticipate and plan for what EPA's ultimate decisions would be, the Commission determines not to penalize DEP through denial of cost recovery for its decision to wait until EPA's CCR determinations in this area were finalized. Had DEP acted prematurely in anticipation of regulations under consideration but not yet implemented, with the expenditure of substantial sums in the process, and with the ultimate EPA decisions differing from those anticipated, DEP risked unjustified expenditures. In 2015, the EPA announced the Clean Power Plan. Had electric utilities incurred costs prematurely to comply, these costs could have been called into question when the U.S. Supreme Court stayed the Clean Power Plan.

A significant example of the ambiguity and uncertainty DEP faced in the management of CCR impoundments is illustrated by reference to a November 1, 2004 Long Term Ash Strategy Study Phase Report addressing 1983 and 1984 CCR repositories at DEP's Sutton coal fired plant in New Hanover County. The 1983 impoundment was unlined and had reached capacity prior to the 2004 report. The 1984 impoundment was lined and was rapidly approaching capacity, and the report identified and classified alternatives for CCR use or disposal to prevent shutdown of the Sutton plant. In the "Problem Description" section of the report, the authoring engineer listed issues either directly or indirectly related to a contribution to the overall ash strategy for the Sutton plant. The issues were described as secondary and not a dictating factor in the solution of the best

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> The Public Staff is not saying that DEP's environmental noncompliance problems are the result of imprudence, because my review did not examine what Duke Energy knew or should have known about coal ash contamination at the time the ash basins were constructed. (Tr. Vol. 18, p. 340)

[1] Public Staff witness Lucas was asked what DEP should have done differently and when it should have done it. He replied:

> ... I can't say exactly what year or exactly what technologies ... I can't go back and tell you exactly what would have happened - - what you should have done at a certain time. I'm not sure what good it would have done for somebody to tell you, oh, 40 years ago you should have put in a clay liner at Asheville and Sutton, put in a concrete liner at the H.F. Lee plant. I mean, you just can't go back and do that kind of assessment. (Tr. Vol. 19, pp. 35-36)

AGO witness Wittliff was asked when in his opinion DEP was imprudent with respect to leachate within the impoundment leaking through the bottom into the groundwater. He responded with respect to Sutton:

> I'd have to - - I'm not sure, but I think it was 2010 or so. I don't want to be quoted on that, but I could dig through here, if you'd like. (Tr. Vol. 15, pp. 99-100)

alternative but as a look at overall environmental structure and stewardship. The first issue addressed the 1983 unlined impoundment that for the most part had ceased to receive CCRs.

> 1983 Pond is Unlined
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> The first issue is that the 1983 ash pond was constructed during a period when it was not required to provide a non-permeable liner, and was constructed with the native sandy soils. This pond has been functionally full since 1983, but is still permitted, and is occasionally used when there are issues requiring the 1984 ash pond to be temporarily dry. The current environmental atmosphere is that these ponds will eventually have to [sic] emptied and placed in a lined containment to eliminate the leaching of the ash products into the groundwater system. This is an issue that is not currently being pressed, but it is anticipated that with the tighter environmental conditions it will soon become an emergent issue. This issue is aggravated by the fact that a test monitoring well located 300' from [sic] edge of the 1983 ash pond has shown high levels of arsenic during the past two quarterly tests. This may or may not be related to the unlined ash pond. A recent study by an independent firm indicated this concern may be less than originally thought. It could be mitigated by adding monitoring wells to the NPDES permit, but could still pose an issue in the future. There is also a county well water source approximately 1200' from the test well that is monitored by the county.

Elsewhere in the report under the "Do Nothing" alternative, the author stated:

> It is assumed that the North Carolina Division of Water Quality (NCDWQ) will require the 1983 ash pond to be emptied and lined to comply with current ash pond regulations. For the purpose of this study it is estimated that there is a 5% chance annually of the ash pond required to be relined starting 2007, and that in 2013 there will be a 10% chance annually thereafter until 2019.

In 2018, it is less than clear as to what the author refers to as the "current environmental atmosphere" or "current ash pond regulations," but the author's speculation as to if and when unlined impoundments might have to be dewatered and excavated was off the mark. The EPA's CCR rule was passed in 2015 and the NC CAMA was passed in 2014 with deadlines a number of years beyond that. DEP did not choose the alternative recommendation in the report, creation of an industrial park, nor did it excavate the unlined 1983 impoundment. The report contains no recommendation to excavate the 1983 impoundment solely for environmental remediation. The Commission is unable today to say how in the past the 1983 impoundment would have been excavated and how the excavated CCRs would be placed in a lined impoundment, what the cost would have been and what cost recovery treatment would have been appropriate. Indeed, the 1983 impoundment today is being excavated pursuant to express EPA and DEQ guidelines, and the parties to this case vigorously contest how compliance with these requirements should be accomplished and what the cost should be.

The purpose of the report was to determine the best course based upon the fact that the 1984 lined ash pond was reaching capacity and would be non-operational by June 2006. It is important to note that the author was indicating that the 1984 ash pond would be non-operational under the NPDES permit due to capacity constraints as opposed to environmental concerns.

Intervenors are advocating substantial disallowances in this case for expenditures DEP incurred to meet CAMA deadlines, such as at Sutton, before all of the regulatory requirements had been finalized. A substantial area of contention is exceedances and environmental violations addressing harmful constituents in coal ash even though determinations with respect to naturally occurring levels of background concentrations of these constituents have not been established. Rules for regulating seeps from dikes are yet to be finalized. Even as DEP continues to remediate, state regulatory agencies must review and approve the process and may impose additional restrictions, limitations and requirements. Even subsequent to EPA CCR rules and CAMA, the General Assembly enacted the MEA, changing the requirements for the Asheville plant remediation. Closure options for each of the CCR impoundments are site specific. Even now, Intervenors criticize the liners DEP has selected, asserting DEP is spending too much. Others advocate that this Commission supersede the authority of environmental regulators and require excavation of all DEP's impoundments and prohibit cap in place. The Commission is unable to recreate the past and place a price tag on remediation costs that might have been incurred in anticipation of environmental requirements.

This Commission's responsibility is cost recovery. Environmental regulators must oversee protection of the environment and public health. The Commission's responsibility is to determine whether coal ash remediation costs as required by environmental regulators should be recoverable through rates.

Another factor the Commission must address is the imposition of requirements of CAMA in addition to those of EPA. The evidence in this case is that the level of transportation costs being contested arises from more aggressive CAMA deadlines and uncertainty over the timing of the granting of regulatory permits for replacement impoundments. Except as addressed generically elsewhere, the Commission is reluctant to second-guess, with minor exception, specific DEP decisions on its attempts to comply with these requirements in a 20/20 hindsight fashion. Likewise, the Commission is reluctant, except in limited fashion, to penalize DEP for good faith efforts to comply with state statutes irrespective of the factors motivating the General Assembly to impose them.

Conversely, the Commission is unable to find DEP faultless in the dilemma it has faced. Much testimony addresses the issue of whether DEP's mismanagement of CCRs "caused" the General Assembly to enact CAMA. DEP argues that other nearby states enacted CCR remediation statutes in addition to EPA's CCR rules, and that the Dan River spill affected the timing but not the substance of CAMA's requirements. The Commission is unable to conclude that DEP mismanagement is the primary cause of CAMA. Nevertheless, the provisions of CAMA directly address remediation of DEP CCR repositories and impose accelerated deadlines with respect to them. The Commission therefore is unable to conclude that DEP mismanagement to which it admitted in the federal criminal court proceeding was not at least a contributing factor. Even DEP witness Wright's testimony suggests as much. While DEP presents persuasive evidence that its alleged mismanagement has not been supported and was not the cause of CAMA, this evidence is difficult to reconcile with its admissions and guilty pleas before the federal district court in the criminal proceeding. DEP represented that it mismanaged its CCR activities.

The Commission's conclusions with respect to the impact of DEP's mismanagement as a contributing factor to the enactment of CAMA are significant in two ways. First, the Commission determines that this conclusion adds support to the Commission's assessment of a management penalty arising primarily from the Company's admissions of mismanagement in the federal criminal case. Secondly, it supports the Commission's determination to reject more discrete disallowances such as those addressed by the Public Staff with respect to Sutton and Asheville transportation costs. The Commission deems these costs traceable to CAMA timelines, implemented in part in response to DEP's CCR management practice, but is unpersuaded that the quantification of the costs is accurate or that the severity of the proposed disallowances is justified.[1] Consequently, the Commission takes the incurrence of these costs into account in establishing the amount of its management penalty.

DEP admits to pervasive, system-wide shortcomings such as improper communication among those responsible for oversight of coal ash management. As stated above, while the Commission cannot state that CAMA would not have been passed or that its requirements other than accelerated deadlines would have been less onerous but for DEP's mismanagement of its CCR activities, neither can it state that DEP activities were without impact on the CAMA provisions that have resulted in increased costs that are at issue in this case. More fundamentally, in its admissions and pleas of guilty before the federal district court, DEP has outlined acts of criminal negligence through management misfeasance. In so doing, the Commission determines that, irrespective of CAMA, DEP has placed its consumers at risk of inadequate or unreasonably expensive service.

The Commission must regulate DEP pursuant to the requirements of Chapter 62 to see that compatibility with environmental well-being is maintained. G.S. 62-2(a)(5) Service is to be provided on a well-planned and coordinated basis that is consistent with the level of energy needed for the protection of public health and safety for the promotion of the general welfare as expressed in the state energy policy, G.S. 62-2(a)(6). All companies are prevented from violating environmental statutes. G.S 143-215.1. DEP is required to maintain safe and reliable service. As an electric utility, safety usually means safe electric service. In the context of this case, the Commission also determines that it means assuring safe operation of its coal-burning facilities so as not to render the environment unsafe. Declining to acquire and install a relatively inexpensive camera in a decades-old storm water drainage pipe over which the large coal ash impoundment is constructed when engineers repeatedly recommend such installation does not comply with a duty to provide safe service.

Fortunately, Dan River was a plant where coal generation had been discontinued at the time of the 2014 spill. Risers in disrepair, inadequate oversight of impoundment dikes and seeps have not resulted in catastrophic failures causing plants to be taken offline or service disruptions, but DEP's irresponsible management of its impoundments over a discrete period of time placed

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[1] Witnesses Garrett and Moore supplemented their testimony to correct the quantity of CCRs located at the Sutton plant as of January 1, 2015, and adjusted the contingency time from nine months to four months given the projected completion date of excavation of March 2019 rather than October 2015. (Tr. Vol. 18, pp. 171-72, 192.)

its customers at risk of inadequate service and has resulted in cost increases greater than those necessary to adequately maintain and operate its facilities.

Consequently, having pled guilty to management criminal negligence, DEP cannot go without sanction in the form of cost of service disallowances. At the same time, to the extent the Dan River plant spill has contributed to the CCR remediation expense that otherwise would have been lower, the Company has borne responsibility for Dan River remediation costs without ratepayer support. The Company has been penalized by the federal district court. It cannot seek cost recovery of these monetary penalties or remediation assessments. Further, the mismanagement to which DEP pled guilty was only for a fraction of the time DEP operated the impoundments. No evidence was submitted that DEP's management was imprudent from the initial date of operation. The penalties imposed by this Commission take the form of denial of recovery of a return on historic remediation costs that reduce a portion of costs that ratepayers otherwise would have borne. The Commission deems double penalization inappropriate as an unwarranted penalty that has a tendency to unduly threaten the long-term overall well- being of the Company, a situation not in the best interest of its consumers.

A major difficulty the Commission confronts in this case is the identification and quantification of the appropriate CCR remediation adjustment to incurred costs. The record does not contain evidence appropriately quantifying the cost DEP incurred with respect to discrete remediation activities.[1] The Public Staff's witnesses' encountered difficulty in quantifying and supporting the costs for the alleged Sutton and Asheville transportation disallowances and other less specific ones motivates the Commission to resist imposition of discrete cost disallowances. The Commission deems disallowance of the totality of costs, as some parties advocate, unjustified. The Commission deems full recovery, as DEP advocates, unjustified. The Commission deems the Public Staff's 50/50 equitable sharing disallowance unfairly punitive and of questionable legal sustainability. The Commission deems requirements that more costs be imposed than DEQ might require without cost recovery unjustified. Moreover, the Commission deems it inadvisable to approve or suggest future disallowances with respect to CCR remediation expenditures as far away as 2028 and beyond. In sum, the Commission cannot agree with any of the parties in this case and must fashion and quantify a remedy different from any of those advocated before it.

The Commission operates under a legislative mandate that requires it to fix rates that will allow a utility "by sound management" to pay all of its reasonable operating costs, including maintenance, depreciation, and taxes, and earn a fair return on its investment. G.S. 62-133(b)(4).

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[1] AGO witness Wittliff was asked whether he offered any opinion on what he thought the Company's appropriate amount of recovery under the CCR rule should be. He responded:

> ... I would explain that I'd love to have been able to come up with some extremely precise numbers and explain it all to you where it all made crystal clear sense and you could hang your hat on it and that's the number, we can pin that down. The problem is, is that this is, as we've already - - everyone seems to have observed, is it's an extremely complex case with a lot of moving parts, and it's not as easy to - - to make that sort of definitive statement. (Tr. Vol. 15, pp. 77-78)

Further, AGO witness Wittliff was asked why other than for CAMA compliance he performed no dollar-for-dollar analysis. He responded: "[b]ut we just couldn't get comfortable with making a data that we would want to bring to you and say this is the number." (Tr. Vol. 15, pp. 85- 86)

State ex rel. Utils. Comm'n v. General Telephone Co., 285 N.C. 671, 208 S.E.2d 681 (1974). If the Commission finds that a utility has not been soundly managed, it may penalize a utility by authorizing less than a "fair return." Id.[1] The Commission must quantify the penalty by making a finding of what return would have been allowed if there were sound management. Id. The North Carolina Supreme Court has stated that "[t]he size of the penalty is left to the judgment of the commission, but must be based upon substantial evidence, and the penalty must not result in a confiscatory rate of return." Id. General Telephone addressed a rate of return on rate base penalty for mismanagement resulting in inadequate service. In this case, DEP's mismanagement takes the form of admitted inadequate oversight of its CCR activities that placed service to its consumers at risk and, at least indirectly, increased costs.

Consequently, the Commission in the exercise of its judgment and discretion, determines that a management penalty in the approximate sum of $30 million is appropriate with respect to DEP CCR remediation expenses accounted for in the earlier established ARO with respect to costs incurred through the end of the test year as adjusted. This penalty is based on the totality of evidence contained in the record, as recited in detail above, and does not result in confiscation. Had the Commission not imposed this penalty, the ARO costs would have been amortized over five years with a full authorized return on the unamortized balance. The penalty will be imposed by reducing the resulting annual revenue requirement by $6 million (from the return on the unamortized balance in the rate base portion) for each of the five years, resulting in an approximate $30 million management penalty. While this penalty differs in form from that in General Telephone, the Commission determines that conceptually General Telephone provides appropriate precedent. By imposing this management penalty, the Commission does not suggest that further penalty or disallowances with respect to past DEP actions or inactions will be imposed with respect to future CCR remediation expenses. The size of the penalty meets judicial requirements as it is quantified and is not confiscatory.

With respect to CCR remediation costs to be incurred during the period rates approved in this case will be in effect, the Commission determines that the "run rate" or the "ongoing compliance costs" mechanism advocated by DEP will not be approved. By requesting the creation of an ARO, in addition to the run rate, DEP concedes that treating CCR expenditures as a recurring test year expense is inadequate. Future annual costs, the evidence shows, are predicted to vary substantially from year to year. Instead, CCR remediation costs incurred by DEP during the period rates approved in this case will be in effect shall be booked to an ARO that shall accrue carrying costs at the approved overall cost of capital approved in this case (the net of tax rate of return, net of associated accumulated deferred income taxes). The Commission will address the appropriate amortization period in DEP's next general rate case, and, unless future imprudence is established, will permit earning a full return on the unamortized balance. While this ratemaking treatment will, in limited fashion, diminish the quality of DEP's earnings, over time, assuming reasonable and prudent CCR management practices, it permits appropriate recovery.

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[1] See also State ex rel. Utils. Comm'n v. Morgan, 277 N.C. 255, 177 S.E.2d 405 (1970) (holding "that it is not reasonable to construe [the statute] to require the Commission to shut its eyes to 'poor' and 'substandard' service resulting from a company's willful, or negligent, failure to maintain its properties [] and it is obvious that consistently poor service, attributable to defective or inadequate or poorly designed equipment or construction justifies a subtraction ..."

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 57-59

The evidence supporting these findings of fact and conclusions can be found in the testimony of Company witnesses Fountain, Bateman, McGee and Kerin, and the testimony of Public Staff witness Lucas.

In his direct testimony, DEP witness Fountain stated that although costs related to beneficial reuse are included in DEP's base rate case, the Company believes that certain amounts are more appropriately recovered through the fuel clause. (Tr. Vol. 6, p. 39 n.1.)

Witness Bateman testified that of the $260.3 million expected deferred balance, $15.1 million, $13.8 million of spend and $1.3 million of return, is related to 2017 beneficial reuse projected costs. As noted by witness Fountain, witness Bateman stated that these amounts are included in the Company's request, but DEP believes that these costs are more appropriately recovered through the annual fuel rider. Witness Bateman explained that if the Commission approves the fuel rider treatment requested by the Company, DEP will remove $15.1 million from the deferred balance in this adjustment. (Tr. Vol. 6, pp. 122-23.)

In her direct testimony, Company witness McGee testified that the beneficial reuse of CCR constitutes a sale of a by-product produced in the generation process, and, therefore, associated gains or losses on the sale should be included in the fuel adjustment clause under G.S. 62-133.2 (a1)(9). (Tr. Vol. 10, p. 104.) According to witness McGee, a sale has occurred when the title to a by-product is transferred to a third party, and the by- product, having value to the third party, will be beneficially reused. (Tr. Vol. 10, pp. 104- 05.) In this particular case, the amounts for which the Company is requesting recovery represent a net loss on the sale of CCR that is to be used as structural fill, which is a beneficial reuse. She testified that the particular transaction, as further discussed in witness Kerin's testimony, involves the sale of CCR produced at DEP's Sutton coal plant, and therefore the input to the by-product is the coal that has been burned at Sutton to produce generation. Thus, she contended that such coal burned has been and continues to be a "fuel or fuel-related cost" under the fuel clause statute as described above. Witness McGee testified that a sale of a by-product is different than disposal of a by- product in that the disposal of a by-product may involve some movement of the by-product and/or transfer of title, but there is no reuse or alternative use of the by-product. According to witness McGee, for transactions that the Company considers to be a sale, the by- product's intrinsic value is recognized in the reuse of the by-product. (Tr. Vol. 10, p. 105.) Finally, witness McGee cited certain statements of the Commission in a 2016 Commission Report to the North Carolina General Assembly[1] (Commission Report) regarding incremental cost incentives related to CCRs, filed in Docket No. E-100, Sub 146, as supportive of the Company's position that beneficial reuse constitutes a sale under the fuel adjustment clause. (Tr. Vol. 10, pp. 105-06.)

Company witness Kerin testified that DEP is now selling excavated ash for reuse in the Brickhaven mine reclamation project, a large scale, fully-lined, beneficial reuse project in

[1] Report of the North Carolina Utilities Commission to the Joint Legislative Commission on Governmental Operations, the Joint Legislative Transportation Oversight Committee, and the Environmental Review Commission Regarding The Incremental Cost Incentives Related To Coal Combustion Residuals Surface Impoundments For Investor-Owned Public Utilities In North Carolina, January 15, 2016.

Moncure, North Carolina. (Tr. Vol. 16, p. 116.) He testified that he agreed with Company witness McGee that the certain beneficial reuse costs are more appropriately recovered through fuel clause proceedings. According to witness Kerin, coal has been used as the fuel to produce power at DEP's Sutton plant. A by-product of that process is CCR. As a means to handle that by-product, CCR is sold to the Brickhaven mine to be used as structural fill, which is a beneficial reuse. (Tr. Vol. 16, p. 117.)

Public Staff witness Lucas testified that the costs relating to the disposal of CCR at Brickhaven, to the extent they are reasonable and prudent, should be recovered in base rates and not through the fuel adjustment clause because the costs did not result from the sale of CCR. (T Vol. 18, p. 230.) Witness Lucas providedbackground regarding the Charah transaction at issue. He testified that Brickhaven is a former clay mine consisting of 333.55 acres located in Chatham County, North Carolina. By Special Warranty Deed recorded on November 13, 2014, Green Meadow, LLC, a wholly owned subsidiary of Charah, purchased Brickhaven from General Shale Brick, Inc. On June 5, 2015, Green Meadow, LLC, and Charah received a permit from DEQ to construct and operate Brickhaven as a "Solid Waste Management Facility, Structural Fill, Mine Reclamation". (Tr. Vol. 18, p. 231.) Charah is a Kentucky-based company, and according to its website, it "is the largest privately-held provider of coal combustion product (CCP) management for the coal-fired power generation industry in the U.S."[1] In its Limited Petition to Intervene in this case, Charah stated that it is a contractor of DEP and is engaged in the remediation of CCR from one or more DEP facilities. (Tr. Vol. 18, p. 19.)

Witness Lucas explained that in July of 2014, Duke Energy Business Services, LLC (DEBS), on behalf of DEC and DEP, issued a bidding event for the excavation, transportation, and off-site storage of the full volume of CCR at four sites: Riverbend, Dan River, and Sutton in North Carolina and W.S. Lee in South Carolina. On October 3, 2014, DEBS opened a bidding event for the Phase 1 work activity (excavate, transport, and place off-site) ash at Dan River, Sutton, and W.S. Lee. Bids were solicited from three bidders, including Charah. Bids were received on October 9, 2014 (six days later). DEBS selected Charah to provide the services at the Sutton Plant. (Tr. Vol. 18, p. 232.) The purchase of CCR at the plants was not included in the scope of activities for the bidding events; both bidding events requested fixed price proposals to excavate, transport, and store coal combustion residuals from the plants. (Tr. Vol. 18, p. 233.)

Witness Lucas described the contractual arrangement between DEBS and Charah regarding the removal of CCR from the Sutton Plant. He stated that DEBS, as agent for DEP and DEC, and Charah entered into Master Contract 8323 (Master Contract) dated November 12, 2014, for the Phase 1 Excavation Work at the Riverbend and Sutton Plants. Charah is referred to as the "Seller" or "Contractor" in the Master Contract. Charah isnot referred to as a "Buyer". The Master Contract defined the type and scope of work, terms and conditions, pricing, and invoicing. The Master Contract contemplated the issuance of subsequent Purchase Orders as written authorization to proceed with the scope of work identified in the Purchase Order. The Sutton Phase 1 Work Scope was set forth in Exhibit D-2 of the Master Contract. It included the installation of haul roads, engineering the development of a rail loading system, erosion and sedimentation control, and dewatering, ash pond excavation, transportation, unloading, and placement. The Seller's (i.e.,

[1] http://charah.com

Charah's) Pricing Schedule was set forth as Exhibit E. The Pricing Schedule included both fixed pricing and per ton pricing. Witness Lucas testified that the fixed pricing was for mobilization, site preparation, erosion, and sedimentation control work. The per ton pricing was for excavation, loading and transportation, unloading, development, placement, home and field office overhead, and profit. (Tr. Vol. 18, pp. 233-34.) DEBS and Charah entered into Purchase Orders authorizing Charah to transport CCRs from Sutton by truck to Brickhaven and then to construct and transport CCRs by rail to Brickhaven. Purchase Order 1107196 constituted the vast majority of the excavation, transportation, and disposal work for Sutton, and 20 change orders were executed for this Purchase Order. (Tr. Vol. 18, pp. 234-35.)

Witness Lucas testified that nothing in the bid documents, contracts, purchase orders, or change orders for the Sutton Plant produced in discovery assign any value to the CCR to "net" against the cost of the services provided by Charah. (Tr. Vol. 18, pp. 235-36.) When asked to provide all documents that show how the Company or Charah calculated the "net value" or discount value of CCR when setting the cost of services provided by Charah, the Company responded that it had no responsive documents. In addition, when asked how much Charah paid the Company for the Sutton CCR, the Company responded that "there is not a defined price in the operative documents for the Sutton ash." (Tr. Vol. 18, p. 236.)

Witness Lucas testified that DEP and Charah knew how to assign a value to CCR in a sale, as demonstrated by the Master By Product Marketing, Sales, and Storage Agreement (Agreement) entered into by DEC, DEP, and Charah in December of 2013, and associated Work Orders, which obligated Charah to purchase CCR from DEP or DEC, as applicable, at a price as set forth in the Work Orders. This Agreement formed the basis for the sale of CCR at the Belews Creek and Marshall plants via Work Orders entered into by DEC and Charah on January 1, 2014. (Tr. Vol.18, p. 236.)

Witness Lucas asserted that the specific provisions relating to the services and pricing in the Master Contract, Purchase Orders, and change orders for Sutton all support the conclusion that the arrangement was one for Charah to provide ash disposal services to DEP, not for a sale of DEP's CCR to Charah. Although one of the general provisions of the Master Contract stated that the services to be performed by Charah constituted payment by Charah for the CCRs, DEP has admitted that there was no defined price for the CCRs and no documentation showing that the parties assigned any value at all to the CCRs. (Tr. Vol. 18, pp 236-37.) As a result, witness Lucas concluded that the specific provisions of both the Master Contract and Purchase Orders overwhelmingly point to a contract for services, not a sale.

Witness Lucas also addressed the findings in the Commission Report cited by Company witness McGee as support for DEP's position. He testified that the findings in the Commission Report do not support DEP's conclusion that the costs of the beneficial reuse of CCR are recoverable through the fuel clause. The General Assembly in the legislation directed the Commission to specifically address in its report "possible revisions to the current policy on allowed incremental cost recoupment that would promote reprocessing and other technologies that allow the reuse of coal combustion residuals stored in surface impoundments for concrete and other beneficial end uses". The Commission's Report examined the statutory framework for cost recovery and concluded that current policies and practices are adequate to encourage reuse of CCRs for concrete and other beneficial end uses. However, as recognized by the Commission in the Report, recovery through the fuel clause presupposes that there is a sale. On page 13 of the Report, the Commission stated, "Customers' rates are adjusted annually to include profits or losses associated with efforts to sell CCRs for beneficial reuse." On page 14 of the Report, the Commission recognized that "sales of CCRs typically result in immediate net costs to ratepayers." The Commission did not conclude in its Report that the costs of processing CCRs for beneficial use, without a sale, are recoverable in the fuel clause. (Tr. Vol. 18, pp. 237-38.)

Finally, witness Lucas addressed the fact that the Commission has allowed the Company to recover net gains or losses from the sale of CCRs through the Company's annual fuel rider. Witness Lucas stated that if there is an actual sale of CCRs, cost recovery through the fuel clause may be appropriate, if the costs are reasonably and prudently incurred. Where, however, there is a contract for services not involving a sale of CCRs, costs arising from that contract should not be recoverable through the fuel clause. Witness Lucas concluded that the true purpose of moving CCRs from Sutton to Brickhaven is environmental remediation and the disposal of CCRs, and not the sale of a byproduct. (Tr. Vol. 18, pp. 238-39.)

In her rebuttal, Company witness McGee disagreed with witness Lucas' characterization of the contractual arrangement with Charah involving the movement of ash from the Sutton Plant to Brickhaven. She asserted that DEP was compensated for the value of the CCRs. She explained that under the arrangement, the compensation to DEP was expressed indirectly through the values agreed to on other terms and conditions in the contract. In other words, the cost of services provided by Charah would have been higher without the sale of the CCRs from Duke Energy to Charah. She further asserted that the CCRs had value to Charah in that it was used in a process as a substitute foran alternative material. Without the purchase of the CCRs, Charah would have needed to procure topsoil or another material to use as structural fill, an added cost that Charah was able to avoid. She concluded that the overall economics of the sales agreement therefore reflected the intrinsic value of the CCRs. (Tr. Vol. 10, p. 111.)

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

Witness McGee also cited Section 4.2 of Exhibit B in support of the Company's position, which provides in pertinent part that, "payment of the Service Fee by Duke Energy to Contractor . . . together with any Ash that is transferred by Duke Energy, to Contractor under the applicable Purchase Order, constitutes payment in full, by Duke Energy to Contractor for any and all of contractor's costs to perform the Services...." Witness McGee asserted that this section clearly acknowledges that the CCRs serve as partial consideration for the services rendered by Charah. She stated that it was therefore understood and accepted by both parties that the service fee charged by

Charah for its services was offset by the value of the CCRs to Charah, thereby constituting a sale. (Tr. Vol. 10, p. 112.)

Witness McGee also took issue with witness Lucas' characterization of the arrangement as a "disposal". She stated that the CCRs at Sutton were not thrown away or placed in a landfill, but replaced the topsoil that would have been used as structural fill in the reclamation of the Brickhaven mine. Further, she noted that the EPA definition of beneficial reuse is "the reusing of a material in a manner that makes it a valuable commodity, such as use in a manufacturing process or as a structural fill." Based on the EPA definition, witness McGee maintained that the use of the Sutton CCRs as structural fill for the Brickhaven mine indicates that the CCRs were a valuable commodity. (Tr. Vol. 10, p. 113.)

Witness McGee also cited Section 2.1 of Exhibit B, which states, "[t]he Parties desire that Contractor excavate certain quantities of Ash from the Ash Ponds or Onsite Storage, transport such Ash off the Station property for resale to Contractor for beneficial reuse in the production of construction products, as an engineered structural fill and/or for closure of a mine reclamation projects, etc. . . ." (emphasis added). She asserted that both parties clearly contemplated and agreed upon the use of the CCRs, which is expressed in the contract. Accordingly, the purpose of this transaction was the sale of CCRs produced at the Company's Sutton coal plant to Charah for beneficial reuse at Brickhaven. (Tr. Vol. 10, pp. 113-14.)

Finally, witness McGee testified that the Company has included the gain/loss of CCRs in the fuel adjustment clause in the past. Specifically, she noted that the losses on the sale of CCRs from the Asheville plant to the Asheville Airport as structural fill have been included in the fuel adjustment clause since 2008. (Tr. Vol. 10, p. 114) She noted that the Master Contract had the same language as that used for the CCRs from the Asheville Plant, and that the sale of the CCRs was implied since both parties agreed that both the value of the CCRs and the additional funds paid by Duke would constitute full payment for the work as outlined in the associated purchase order. (Tr. Vol. 10, p. 115.)

During cross-examination, Company witness McGee admitted that no particular projects or costs are presented in the Company's fuel filings and that the Commission only approves an overall number in the fuel rates. (Tr. Vol. 10, p. 130.) Further, the Commission did not specifically review or consider the Asheville CCR sale in prior fuel proceedings. (Tr. Vol. 10, p. 131.) She testified that the cost of disposing of CCRs in a landfill would not be a sale and would not be recoverable under the fuel clause. (Tr. Vol. 10, p. 133.) A series of exhibits were introduced (Public Staff [PS] McGee Cross- Examination Exhibits 1-5), which were Company responses to Public Staff data requests. (Tr. Vol. 10, pp. 134-43.) In these data requests, the Public Staff asked the Company to describe in detail and provide documentation in support of its assertion that the transaction between Charah and the Company constitutes a sale of CCRs. When asked to cite the specific language in the contracts and amendments between DEP and Charah that support the Company's assertion, the Company cited Sections 4.1 and 4.2 of Exhibit B of the Master Contract. (Tr. Vol. 10, Public Staff McGee Cross-Examination Exhibit 2.) When asked, "How much did Charah pay the Company for the Sutton coal ash?," the Company responded that "there is not a defined price in the operative documents forthe Sutton ash." Further, when asked to provide all documents that show how the Company or Charah calculated the "net value" of or discount value of coal ash when setting the cost of services provided by Charah, the Company responded that it did not have any responsive documents. (Public Staff McGee Cross-Examination Exhibit 4.)

In Public Staff McGee Cross-Examination Exhibit 5 (Company response to Public Staff Data Request No. 174-1), the Public Staff asked the Company to provide documentation supporting witness McGee's assertion in her rebuttal that "without the purchase of the coal ash, Charah would have needed to procure topsoil or another material to use as structural fill, an added cost that Charah was able to avoid". The Public Staff also asked for information and documentation that shows what Charah would be constructing at the Brickhaven site that requires the use of structural fill. In response, the Company stated that it does not have the requested documentation but is aware that Charah is using the CCRs as structural fill; further, it has no documentation related to Charah's future plans at its Brickhaven mine. (PS McGee Cross Examination Exhibit 5) On further cross-examination, witness McGee did not dispute that the deed to Brickhaven was recorded the day after the Master Contract was signed. She also admitted that managing CCRs is Charah's expertise. (Tr. Vol. 10, p. 144.) Further, witness McGee acknowledged that it was necessary for the Company to pay Chatham County millions of dollars to send the Sutton CCRs to Brickhaven, as demonstrated by portions of a Settlement Agreement between DEP, DEC, and Chatham County dated June 22, 2015, that were read into the record. (Tr. Vol. 10, pp. 145-47.) Regarding Section 3 of Exhibit B, in which the Company transferred title to, risk of loss of, and responsibility for the CCRs to Charah once the CCRs are loaded in to truck or railcar at Sutton for transportation to Brickhaven, witness McGee acknowledged that the provision could also refer to the transfer of liability for the CCRs. (Tr. Vol. 10, p. 150.)

During the confidential portion of witness McGee's cross-examination, several contracts were entered into the record. Public Staff McGee Confidential Cross- Examination Exhibit 6 is the Master Contract, dated November 12, 2014, between Charah and DEBS on behalf of DEP and DEC for the Phase 1 Excavation Work at Riverbend and Sutton and is the Master Contract discussed in witness McGee's and Public Staff witness Lucas' testimony. The costs relating to this contract are what the Company seeks to recover through the fuel clause. (Confidential Tr. Vol. 10, pp. 152-53.) In the Master Contract, Charah is listed as the "Seller". (Confidential Tr. Vol. 10, p. 152.) Exhibit E of the Master Contract contains the pricing schedule for the Master Contract, including pricing for items such as site preparation, excavation, loading and transportation, unloading, development, home or field office overhead and profit, but no pricing for Charah's purchase of the CCRs. (Confidential T 10, pp 153-54) This was the pricing applicable for sending the ash to Brickhaven, as noted in Footnote 1 on page E-2. (Confidential Tr. Vol. 10, p. 154.) The Master Contract also had alternative pricing in the event the CCRs could not be transported to Brickhaven and instead had to be transported to the Anson County Landfill. (Confidential Tr. Vol. 10, p. 154) Witness McGee testified that if this alternative had been used, the costs associated with the Master Contract would not be recoverable under the fuel adjustment clause. (Confidential Tr. Vol. 10, p. 154.)

Public Staff McGee Confidential Cross-Examination Exhibit 7 is Master Contract 8324 dated November 12, 2014, between Waste Management National Services, Inc. (Waste Management), and DEBS on behalf of DEC for the Phase 1 Excavation Work at Dan River and W.S. Lee. The Master Contract and the Waste Management Master Contract 8324 are both dated November 12, 2014. (Confidential Tr. Vol. 10, p. 159.) The Waste Management Master Contract 8324 contains pricing schedules similar to those in the Master Contract. Under the Waste

Management Master Contract 8324, the CCRs from Dan River was to be transported to the Maplewood Landfill Site, and the CCRs from W.S. Lee was to be transported to the R&B Landfill Site in Homer, Georgia. The Waste Management Master Contract 8324 includes the same language used in the Master Contract, i.e., "payment of the Service Fee by Duke Energy to Contractor . . . together with any Ash that is transferred by Duke Energy, to Contractor under the applicable Purchase Order, constitutes payment in full, by Duke Energy to Contractor for any and all of contractor's costs to perform the Services..." Witness McGee testified that the costs associated with the Waste Management Master Contract 8324 should not be recoverable under the fuel clause. (Confidential Tr. Vol. 10, pp. 159-60.)

Public Staff McGee Confidential Cross-Examination Exhibit 10 is Purchase Order 1380566 dated September 25, 2015, authorizing Waste Management to transport CCRs from the Asheville Plant for disposal at R&B Landfill in Homer, Georgia. (Confidential Vol. Tr. 10, p. 161.) On page 4 of this Purchase Order, it states that the terms and conditions of Master Contract 8324 govern the work. (Confidential Tr. Vol. 10, p. 162.) Witness McGee testified that the costs associated with the Purchase Order would not be eligible for recovery under the fuel adjustment clause. (Confidential Tr. Vol. 10, p. 163.)

Public Staff McGee Confidential Cross-Examination Exhibit 8 is a Master Contract dated December 15, 2016, between Trans Ash, Inc. and DEBS on behalf of DEP and other Duke Energy entities for "Ash Project Services." Public Staff McGee Confidential Exhibit 9 is Master Contract dated March 14, 2017, between Parsons Environment & Infrastructure Group, Inc. and DEBS on behalf of DEP and other Duke Energy entities for "Ash Project Services".

All four Master Contracts include as Exhibit B the "Duke Energy Standard Terms and Conditions for Ash Services as Agreed upon By Seller and Duke Energy", and contain the same or substantially similar language in Sections 3, 4.1, and 4.2. This is the language the Company cites in support its claim that the costs associated with the Master Contract should be recoverable under the fuel adjustment clause. (Confidential Tr. 10, pp. 164-65) In response to a request by the Commission, the contract between Charah and Progress Energy, Inc., dated June 18, 2007, for the excavation, transportation, and resale of ash from the Asheville Plant to the Asheville Regional Airport Authority (Asheville Contract) was filed by DEP as Confidential Late Filed Exhibit 3. Section 5.1 of the Asheville Contract provided that the work performed by Charah constituted payment for the CCRs.

During the cross-examination of Company witness Kerin on his direct testimony, two exhibits were introduced. Public Staff Kerin Cross-Examination Exhibit 1, an excerpt (with confidential portions removed) of an Executive Summary, summarized the process undertaken to select the vendors to excavate the CCRs at Sutton, as well as Dan River, W. S. Lee, and Riverbend. (Tr. Vol. 17, p. 40.) The document describes the bidding events that took place and the bid evaluation process. Bids were evaluated based on technical and commercial criteria, including the bidder's acceptance level of Duke Energy Terms and Conditions. (Tr. Vol. 17, p. 42.) The document also describes the key contract provisions that would apply to the work, regardless of disposal method. (Tr. Vol. 17, pp. 42-43.) Included in the key contract provisions was a requirement that the work be completed under the Duke Energy Standard Terms and Conditions for Ash Reclamation and Placement. (Tr. Vol. 17, p. 43.)

Public Staff Kerin Cross-Examination Exhibit 2 is a memorandum (Subject: Addendum Number 1) dated October 17, 2014, from Joseph Frondorf of Duke Energy Corporation to the bid teams for the bidding event summarized in Public Staff Kerin Cross- Examination 1. (Tr. Vol. 17, pp. 43-44.) Attached to the memorandum was Duke Energy's Standard Terms and Conditions for Ash Reclamation and Placement, discussed in the Executive Summary as a key contract provision and ultimately incorporated in the contracts (as Exhibit B) with Charah for Sutton and Riverbend and Waste Management for Dan River and W. S. Lee. (Tr. Vol. 17, pp.44-45.)

In its post-hearing Brief, NC WARN contends that the use of CCRs at Brickhaven is not a "beneficial use," citing the ruling of a Superior Court revoking state permits allowing CCRs to be used as mine reclamation in areas not already mined or otherwise excavated.

Discussion and Conclusion

DEP seeks to recover certain CCR costs related to the excavation and movement of CCRs from the Sutton Plant in Wilmington, North Carolina to the Brickhaven facility in Chatham County, North Carolina, through the fuel adjustment clause on the grounds that the beneficial reuse of CCRs constitutes a sale of a by-product produced in the generation process. The fuel adjustment statute, G.S. 62-133.2, allows electric public utilities to recover through an annual rider certain fuel and fuel-related costs. G.S. 62-133.2(a1)(9) provides:

> Cost of fuel and fuel-related costs shall be adjusted for any net gains or losses resulting from any sales by the electric public utility of by-products produced in the generation process to the extent the costs of the inputs leading to that by-product are costs of fuel or fuel-related costs.

It is undisputed that CCRs are a by-product produced in the generation process. The issue is whether the transaction between DEP and Charah as reflected in the Master Contract represents a sale of a by-product.

This is the first case in which the Commission has been squarely presented with this issue. The Company contends that the fact that the Commission approved recovery of costs through the fuel adjustment clause related to a similar contractual arrangement between Charah and DEP to remove CCRs from the Asheville Plant and transport it to the Asheville Airport demonstrates that the costs related to the Master Contract are also similarly recoverable. The Commission disagrees. Nothing regarding the Asheville contractual arrangement was specifically presented by the Company, the Public Staff, or any other party in the Company's relevant fuel filings, and, therefore, the present issue was not specifically considered by the Commission. Consequently, the fuel factors approved by the Commission that included the Asheville transaction costs do not constitute specific approval of the transaction as a "sale of a by-product" and do not preclude the Commission from considering this issue now.

In addition, the findings of the Commission Report cited by witness McGee do not support a finding that the costs associated with beneficial reuse, without a sale, are recoverable through the fuel adjustment clause. The General Assembly directed the Commission to specifically address in its Report "possible revisions to the current policy on allowed incremental cost recoupment that would promote reprocessing and other technologies that allow the reuse of coal combustion residuals stored in surface impoundments for concrete and other beneficial end uses." The Commission Report examined the statutory framework for cost recovery and concluded that current policies and practices are adequate to encourage reuse of CCRs for concrete and other beneficial end uses. However, as noted by Public Staff witness Lucas and as recognized by the Commission in the Report, recovery through the fuel clause presupposes that there is a sale. On page 13 of the Report, the Commission stated, "Customers' rates are adjusted annually to include profits or losses associated with efforts to sell CCRs for beneficial re- use." On page 14 of the Report, the Commission recognized that "sales of CCRs typically result in immediate net costs to ratepayers." The Commission did not conclude in its report that the costs of processing CCRs for beneficial use, without a sale, are recoverable in the fuel clause.

Finally, the record in this case does not support a finding that the costs associated with the Master Contract resulted from a "sale" of CCRs. The Company admitted both in data responses and during the expert witness hearing that nothing in the Master Contract or its associated documents included pricing or discounts to account for a sale of the CCRs. Further, nothing in the bid documents, contracts, purchase orders, or change orders relating to the Master Contract assign any value to the CCRs to "net" against the cost of the services provided by Charah. Moreover, the evidence shows that DEP and Charah knew how to assign a value to CCRs in a true sale. Public Staff witness Lucas testified, and the Company did not challenge, that pursuant to a Master By Product Marketing, Sales, and Storage Agreement (Agreement) entered into by DEC, DEP, and Charah in December of 2013, and associated Work Orders, Charah was obligated to purchase CCRs from DEP or DEC, as applicable, at a price as set forth in the Work Orders. This Agreement formed the basis for the sale of CCRs at the Belews Creek and Marshall plants via Work Orders entered into by DEC and Charah on January 1, 2014.

The Company relies on the existence of three provisions in Exhibit B of the Master Contract in support of its contention that a sale of CCRs occurred. Company witness McGee states in her testimony that per Section 3 of the Master Contract, the Company transferred title to, risk of loss of, and responsibility for the CCRs to Charah once the CCRs wre loaded in to truck or railcar at Sutton, indicating the CCRs had value. However, on cross-examination, she agreed that this language could be interpreted to mean the transfer of liability for the CCRs. This interpretation – that transfer of title relates to the transfer of liability - is supported by the language in the second sentence of Section 3, which states that the Contractor is not assuming any responsibility for any liabilities arising out of or relating to the creations, existence, storage, or handling of the ash prior to the time title to the ash passes to Contractor. In addition, the Scope of Work Clarification provided to the bidders of the Sutton project and attached to PS Kerin Cross-Examination Exhibit 2, page 2, states, under paragraph 6, "Once the ash is loaded into the transport vehicle, <u>liability of shall transfer to the bidder</u>, and shall remain with the bidder unless it is transfer (sic) to the owner of the final ash storage location." (emphasis added) The Commission finds and concludes that Section 3 of the Master Contract does not support a finding that the Sutton CCRs had value. On the contrary, the balance of this evidence supports the conclusion that possession of the CCRs represented a liability, not an asset.

The Company also cites Sections 4.1 and 4.2 of Exhibit B of the Master Contract, which in essence state that the services performed by Charah constitute payment for the CCRs. The

Commission is not persuaded that inclusion of these provisions demonstrate that a sale of CCRs occurred. These provisions are part of the Duke Energy Standard Terms and Conditions for Ash Reclamation and Placement that have been included in other contracts for CCR services, regardless of the type of service and disposal method. PS McGee Confidential Cross-Examination Exhibit 7, the master contract for the Phase 1 Excavation Work at Dan River and W. S. Lee, contain the same provisions and pricing schedules similar to the Master Contract, and witness McGee admitted that the costs incurred under that contract should not be recoverable under the fuel clause, as the CCRs were landfilled. The Commission finds that these provisions are boilerplate that do not support the conclusion that a sale of the Sutton CCRs occurred.

Based on a preponderance of the evidence, the Commission finds and concludes that the specific provisions relating to the services and pricing in the Master Contract, Purchase Orders, and change orders for Sutton, along with the circumstances surrounding the transaction, all support the conclusion that the arrangement was one for Charah to provide CCR excavation, transportation, and disposal services to DEP, not for a sale of DEP's CCRs to Charah under G.S. 62-133.2(a1)(9).

As noted at the beginning of this discussion, DEP witness Bateman testified that of the $260.3 million expected deferred CCR cost balance, $15.1 million -- $13.8 million of spend and $1.3 million of return -- is related to 2017 Charah projected costs. Witness Bateman explained that if the Commission approves the fuel rider treatment requested by the Company, DEP will remove $15.1 million from the deferred balance in this adjustment. (Tr. Vol. 6, pp. 122-23.) The Commission having denied the recovery of the $15.1 million Charah costs in fuel rates, the recovery of this $15.1 million is left in DEP's $260.3 million deferred CCR balance for consideration of recovery in DEP's base rates.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 60

The evidence supporting this finding of fact and conclusion can be found in the Application, Form E-1, the testimony of Company witness Wright, and the testimony of Public Staff witnesses Lucas and Maness.

Public Staff witness Maness stated that CCR costs prudently incurred from January 2015 through August 2017 (i.e., costs not subject to Public Staff recommended disallowances apart from equitable sharing) should be allowed provisional cost recovery. (T Vol. 19, p. 303) He explained that the reasonableness of some of those costs may depend on the outcome of legal proceedings or other legal determinations, as described by witness Lucas. (Id.) Witness Lucas described how past actions of DEP may be determined to be violations in the future with respect to both ongoing review by DEQ and pending litigation. These circumstances affect the ability of the Public Staff and other parties to recommend disallowances for specific costs because an environmental violation must be established before there is any decision on whether to disallow the cost of remedying the violation.

In particular, witness Lucas noted that DEQ is still in the process of deciding which unauthorized seeps will be allowed under renewed NPDES permits and which will require some other action by DEP. (Tr. Vol. 18, pp. 253-54.) He stated in testimony prefiled in October 2017 that DEQ and DEP expected to reach consensus on provisional background threshold values for constituents of interest, meaning that the number of groundwater exceedances that are actual violations would not be known until then. (Tr. Vol. 18, pp. 254, 256.) He further stated that monitoring data to determine compliance with, and violations of, the CCR Rule standards would not be available until January 2018. (Tr. Vol. 18, p. 254.) In supplemental testimony, witness Lucas was able to update the groundwater violations of the 2L regulation. (Tr. Vol. 18, p. 290; Revised Lucas Exhibit 6) In addition, the Public Staff noted that there are pending lawsuits against DEP regarding the Mayo and Roxboro plants that allege violations of environmental laws. (Tr. Vol. 18, pp. 260-62.) The outcome of these lawsuits will affect how much DEP must spend for corrective action, and whether associated litigation costs should be deemed reasonable.

Witness Wright disagreed with the Public Staff's recommendation of provisional cost recovery for coal ash expenditures prudently incurred from January 2015 through August 2017, based on the argument that the appropriateness of such recovery may depend on the outcome of legal determinations. He noted first that this would appear to be retroactive ratemaking. He also stated that the standard is that the utility makes the best possible decisions on expenditures based on the information available at the time, and determinations of the reasonableness and prudency of these costs should not depend on future outcomes of legal proceedings but what was known or knowable at the time. (Tr. Vol. 20, pp. 165-66, 178.)

Provisional cost recovery is appropriate in certain circumstances. However, the Commission is not persuaded that there is good cause to order provisional cost recovery of DEP's CCR costs that are approved in this Order. The Commission has weighed the Public Staff's and other intervenors' concerns about the pending insurance lawsuits and pending determinations by DEQ, EPA, and certain courts, that will establish whether past actions of DEP amount to environmental violations against the uncertainty that is inherent in provisional rates. With regard to the insurance litigation, DEP has committed that insurance proceeds recovered by DEP will benefit ratepayers as an off-set to DEP's CCR costs. Further, the insurance proceeds are not known and measurable as of the end of the test year. Moreover, the Commission has included in this Order specific reporting requirements and other conditions with which DEP must comply regarding the insurance proceeds.

With respect to pending determinations by EPA and DEQ, the Commission is not inclined to delay its work in order to wait for these agencies to complete their work. As a result, on balance the Commission finds and concludes that it will not order that the CCR cost recovery in this docket is provisional.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 61-62

The evidence supporting these findings of fact and conclusions can be found in the Application, Form E-1, the testimony of Company witnesses Kerin and Bateman, and the testimony of Public Staff witness Maness.

CAMA Costs Identified by DEP as North Carolina Only

Witness Maness recommended two adjustments to the jurisdictional allocation factors used by the Company to allocate system-level CCR costs to the North Carolina retail jurisdiction. The first such adjustment was to allocate the costs DEP identified as "CAMA-only" costs by a comprehensive allocation factor, rather than DEP's proposed factor, which did not allocate costs to the South Carolina retail jurisdiction. Company witness Bateman stated in her testimony that there is a small portion of CCR management costs that under CAMA that are unique to North Carolina and appropriate for direct assignment to North Carolina. Company witness Kerin stated that these costs include groundwater wells used specifically for CAMA purposes and permanent water supplies provided to North Carolina customers pursuant to North Carolina law. Consequently, the Company utilized North Carolina retail allocation factors for its CAMA-only costs that did not allocate any of the system level costs to South Carolina retail operations. However, witness Maness stated that even though some of the costs incurred by DEP are being incurred pursuant to North Carolina law, it is still fair and reasonable to allocate those costs to the entire DEP system because the coal plants associated with the costs are being or were operated to serve the entire DEP system. (Tr. Vol. 18, pp. 305-06.)

In rebuttal, Company witness Bateman testified that in general she agreed with witness Maness that the costs of a system should be borne by all of the users of the system. However, she stated that the Company had identified very specific cost categories, groundwater wells used specifically for CAMA purposes and permanent water supplies provided to North Carolina customers pursuant to North Carolina law, and that they should be treated as an exception to this general rule, due to their nature as being unique to North Carolina. She stated that this unique treatment would be consistent with other examples where the Commission had allowed direct assignment to North Carolina, including the incremental costs associated with the North Carolina Renewable Energy and Energy Efficiency Standard (REPS) and the costs to comply with the North Carolina Clean Smokestacks Act. (Tr. Vol. 6, pp. 142-43.)

After consideration of this issue, the Commission finds and concludes that the adjustment recommended by Public Staff witness Maness to allocate all system-level CCR costs by a comprehensive allocation factor produces a more reasonable and appropriate outcome than the proposal by the Company to allocate a portion of these costs in a manner that does not allocate them to the South Carolina retail jurisdiction. Although the costs in question were required pursuant to North Carolina law, the costs are inherently related to the burning of coal to provide electricity to the entire DEP system, including the South Carolina retail jurisdiction. The fact that these particular costs are associated with plants that are geographically located in North Carolina is no more relevant with regard to the proper allocation of these costs than it is to the proper allocation of other costs, such as fuel expense and other variable O&M expenses, which are allocated to the entire DEP system.

Further, the Commission concludes that these CAMA compliance costs are distinguishable from the examples of REPS and Clean Smokestacks costs cited by the Company. With regard to REPS costs, it is important to note that those costs are by their very nature in excess of the normal level of costs that would otherwise need to be incurred to provide an equivalent amount of energy to the Company's customers. Thus, it is appropriate that the Commission allocates the REPS costs to North Carolina customers. With regard to Clean Smokestacks costs, the Commission notes that those costs were closely related to a rate freeze that was instituted by the General Assembly for North Carolina retail purposes. However, the legislature could not require a similar freeze to be established with regard to South Carolina retail customers.

CCR Cost Allocation Factors

The second adjustment recommended by witness Maness to the jurisdictional allocation factors used by the Company to allocate system-level CCR costs to the North Carolina retail jurisdiction is to allocate all CCR expenditures by the energy allocation factor, rather than the demand-related production plant allocation factor, as recommended by DEP. Witness Maness testified that he recommended this change because the CCR costs are being incurred because CCRs were produced by the burning of coal to produce energy over the years and, like the cost of coal, should be allocated by energy, and not peak demand. Therefore, according to the Public Staff the energy allocation factor should be used to determine the North Carolina retail portion of these costs. (Tr. Vol. 18, p. 306.)

In rebuttal, DEP witness Hager testified that the costs in question are associated with compliance with federal and state environmental requirements related to closing CCR basins. She stated that residual end of life costs typically and logically follow the cost of the plant, which is allocated based on demand, and that end of life costs (removal costs) and salvage values are factored into depreciation rates, which are allocated based on demand, as they were in the most recent DEP general rate case. Additionally, witness Hager testified that use of the demand-related factor is consistent with end-of-life nuclear fuel costs in nuclear decommissioning costs. (Tr. Vol. 10, pp. 289-90.)

At the hearing, witness Maness was asked several questions by the Commission and by counsel for DEC regarding his recommendation, particularly how it compared to the allocation methods used for spent nuclear fuel storage. In summary, witness Maness responded that the allocation methods used for nuclear fuel could differ based on the stage of life the fuel is in. When the fuel itself is consumed, it is allocated according to energy. He stated that when it is in a state of interim storage, it may be allocated by different factors, but the portion of interim storage costs embedded in nuclear decommissioning expense is allocated by demand; and the costs paid for permanent storage, to date have largely been allocated on an energy basis. (Tr. Vol. 19, pp. 81-82.)

In its post-hearing Brief, CIGFUR maintains that DEP's proposal to allocate CCR costs based on demand is appropriate. CIGFUR states that CCR, unlike coal, has no energy potential, is not a fuel, and its cost is not recoverable through the fuel clause. (Tr. Vol. 18, p. 363-65. (Maness)) Further, CIGFUR notes that the environmental liability DEP is now tasked with managing is an environmental compliance cost that did not exist when the coal was burned, but arose only much more recently, and that applying a demand factor is consistent with the treatment of end-of-life nuclear fuel costs and nuclear decommissioning costs. (Id. at 289-90.)

In its post-hearing brief, NCSEA argues that costs associated with coal ash remediation are appropriately classified as energy-related costs.

The Commission has carefully considered the evidence presented by the witnesses. The evidence indicates that there have been a mixture of allocation approaches used for costs associated with fuel expense and other expenses over the years, with fuel and other energy-related costs following an energy allocation approach, while other costs, including certain spent fuel costs and costs associated with end-of-life plant costs, have been allocated consistent with the allocation of production plant, which the Commission notes has sometimes been based on peak demand and sometimes based on some type of average of energy and peak demand. The Commission can see credible arguments for the allocation of CCR clean-up costs on both sides – production plant or energy. However, CCR is a residual of the burning of coal in order to produce electricity. For every kWh of electricity that is produced by coal-fired generation, there are CCRs produced that must be properly handled and stored. Thus, the quantity of CCRs and the cost of storing them are energy driven. As a result, the Commission finds and concludes that the appropriate and reasonable course of action is to allocate the CCR costs by the energy allocation factor.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 63-65

The evidence supporting these findings of fact and conclusions is contained in the testimony of DEP witness Fountain and DEP's Late-Filed Exhibit 1.

Witness Fountain testified that DEP is engaged in litigation in Mecklenburg County involving 57 insurance policies purchase by DEP and DEC from 1971 to 1986. The lawsuit was filed on March 29, 2017. Witness Fountain testified that the lawsuit was filed after Duke Energy Corporation requested that the insurance companies provide coverage in connection with DEC's and DEP's liability for CCR costs. All of the insurance companies refused to pay Duke anything under the policies. Witness Fountain testified that DEP is seeking to recover its CAMA compliance costs and "seeking insurance proceeds that would offset those customer costs to the extent that they are provided in conjunction with these rate proceedings." (Tr. Vol. 7, p. 375.)

At the request of the Commission, on December 6, 2017, DEP filed its Late-Filed Exhibit 1. In summary, DEP's exhibit responds to the Commission's inquiries regarding the pending lawsuit, Duke Energy Carolinas, LLC, et al. v. AG Insurance SA/NV, et al., Case No. 17-CVS-5594, Superior Court (Business Court), Mecklenburg County, State of North Carolina (Insurance Case), in which DEP seeks insurance recovery for certain CCR related costs. DEP states that any net insurance recoveries from the Insurance Case will be used to reduce the CCR costs paid by DEP's customers. DEP further states that the Insurance Case seeks recovery under 19 excess-level third-party liability insurance policies issued to DEP's predecessor, Carolina Power & Light Company, between 1971 and 1986. DEP states that each policy will make a pay-out only after a "self-insured retention" – similar to a deductible – is satisfied, which deductibles range from $100,000 to $500,000 per policy. In addition, DEP states that the value and recoverability of the insurance proceeds is hotly disputed, and that each insurer in the Insurance Case takes the position that DEP is entitled to no recovery. Moreover, DEP states that "[i]t is possible that net recovery on behalf of the DEP ratepayers could amount to as much as $300 million dollars over time as future costs are incurred taking into account all of the DEP policies sued upon." DEP Late-Filed Exhibit 1, at p. 2.

Several parties questioned whether DEP has sufficient direct interest in the Insurance Case to motivate DEP to make a reasonable effort at recovering the maximum amount possible to off-set its customers' CCR costs. For example, in its post-hearing Brief Fayetteville PWC recommended that the Commission place three conditions on DEP's recovery of insurance proceeds: (1) DEP will be entitled to the immediate collection from the deferred account of an amount equal to the insurance proceeds that DEP secures for coal ash remediation from the Mecklenburg Case, provided that the offsetting insurance proceeds are credited to DEP's ratepayers; (2) if DEP fails to recover all or any of the insurance proceeds, DEP's CCR cost recovery should be reduced by the amount not recovered, unless DEP satisfies the Commission that it was not at fault in failing to get full insurance recovery; and (3) DEP would not be allowed to accrue a carrying charge on its deferred costs commensurate with any amount of insurance proceeds that it does not recover.

The AGO posits that ratepayers should not bail out DEP from its failure to pursue insurance coverage. Currently, DEP is seeking insurance coverage and has indicated that the total amount of recovery of policies sued upon "may total approximately" between $172 million to $200 million per occurrence. The Company further states that the net recovery on behalf of ratepayers could amount to as much as $300 million. The Company has agreed to use the insurance proceeds to offset the amounts it is otherwise seeking to recover; however, the AGO argues that DEP is disinterested in the outcome. The AGO contends currently there is no downside to DEP if it loses the insurance cases because DEP does not view itself as a stakeholder in the outcome. Further, the AGO contends that DEP might have not filed its claims in time and that the statute of limitations might have run. The AGO requests that if recovery is allowed that the Commission should earmark $300 million as being recovered in damages from the insurance case. The AGO further requests that the Commission should not allow a rate of return on the portion of the coal ash costs that may be recovered via the insurance case.

The Commission is not persuaded that it should adopt Fayetteville's PWC's first recommendation. It appears that the suggestion that DEP be allowed "immediate collection" from the deferred account would not require any Commission review of the deferred CCR costs for prudency or reasonableness. Thus, for example, if DEP settled the litigation for $200 million, it would immediately collect $200 million from the deferred account and be required to immediately credit ratepayers for $200 million. However, if $100 million of DEP's $200 million deferred CCR costs was not prudently or reasonably incurred, then $100 million of the insurance proceeds would go for CCR costs that should be disallowed.

The Commission agrees in principle with Fayetteville's PWC's second recommendation and the AGO's contentions. DEP is representing the interests of its ratepayers in the Insurance Case. Therefore, the Commission finds it appropriate to hold DEP to the same standard of care that DEP is required to exercise each day in providing electric service. That standard is one of reasonableness and prudence. If the parties to this docket, or the Commission on its own motion, raise meritorious issues about DEP's representation of the interests of ratepayers in the Insurance Case, DEP shall bear the burden of proving that it exercised reasonable and prudent efforts to obtain the maximum recovery in the Insurance Case.

With respect to Fayetteville's PWC's third recommendation as well as the AGO's request, the Commission again agrees in principle. However, a blanket denial of carrying costs based solely on DEP's failure to recover every dollar of insurance coverage would be unfair. Rather, the Commission concludes that if DEP exercises reasonable care in representing its ratepayers' interests in the Insurance Case, then DEP should be entitled to receive its full authorized carrying charges on the deferred account. As stated above, if there is a meritorious issue raised about DEP's representation of the interests of its ratepayers in the Insurance Case, DEP shall bear the burden of proving that it took reasonable and prudent steps to obtain the maximum recovery. If DEP fails to meet this burden, the Commission can deny DEP carrying costs on that amount of insurance proceeds that were not recovered as a result of DEP's lack of reasonable and prudent efforts.

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 66

The evidence supporting this finding of fact and conclusion is contained in the testimony of DEP witnesses Bateman and Simpson, and Public Staff witness Maness.

DEP witness Bateman testified that DEP is requesting authority to establish a regulatory asset in which to record and defer the cost of existing AMR meters that are replaced by AMI meters. She stated that the Company's Depreciation Study recovers the net value of the meters being replaced over three years, which is the expected AMI deployment period.

DEP witness Simpson testified that pending a management review and approval by the Duke Energy Board of Directors later this year, DEP plans to begin a full deployment of AMI meters in 2018. He also noted the testimony of witness Bateman regarding DEP's request to establish a regulatory asset in which to record and defer the cost of existing AMR meters that are replaced by AMI meters.

Public Staff witness Maness testified that the Public Staff does not oppose the establishment of a regulatory asset to track the remaining depreciation of replaced meters. Further, he recommended that the replaced meters be depreciated using their estimated remaining useful life of 18.3 years, rather than over three years, as recommended by DEP.

The Commission finds and concludes that DEP should be allowed to establish a regulatory asset account and defer to that account the cost of existing AMR meters replaced by AMI meters. However, the approval granted herein is without prejudice to the right of any person to contest the recovery of the amount of the regulatory asset in future rates, and is without prejudice to the Commission's authority to deny or reduce such recovery if the Commission concludes that DEP has not complied with the Commission's rules or other requirements.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 67

The evidence supporting this finding of fact and these conclusions is contained in the testimony of DEP witness Bateman.

With regard to DEP's CCR costs from 2018 forward, DEP witness Bateman testified that DEP is requesting to establish a regulatory asset/liability account and defer to this account the portion in annual rates that is more than DEP's actual costs, or the amount in annual rates that is less than DEP's actual costs. In essence, the asset/liability account would be a tool used to true-up the difference in DEP's next general rate case.

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 68

In the post-hearing briefs of CUCA and other intervenors, the parties contended that the Commission should adjust DEP's rates to incorporate the effect of the federal income tax decrease included in the Federal Tax Cuts and Jobs Act of 2017 (FTCJA). CUCA estimates that the annual monetary value in the tax reduction is approximately $116.9 million as stated in its comments in Docket No. M-100, Sub 148.

The AGO, in its post-hearing Brief, notes that the Commission has opened a rulemaking proceeding to consider the rate adjustments that public utilities should make to reflect the impact of the tax cut effectuated by the Federal Tax Cuts and Jobs Act (FTCJA). The AGO states that it will participate in the rulemaking and asks the Commission to take appropriate action in this case to order that rates established in this docket will be billed and collected on a provisional basis and that an appropriate deferral will occur, as directed in the FTCJA Order initiating the proceeding, pending final disposition of the rulemaking in order to reflect the benefit of the tax cut in rates.

In its post-hearing Brief, EDF contends that the Commission should require DEP to reflect the federal income tax reduction effectuated by the FTCJA in its new rates. In support of its position, EDF states that a similar event occurred when Congress passed the Tax Reform Act of 1986, which cut the federal income tax rate from 46% to 34%. The Commission opened Docket No. M-100, Sub 113 to investigate how to reflect the federal income tax reduction in rates. In the appeals that followed, the Supreme Court of North Carolina upheld the Commission's authority to reduce utilities' rates to reflect the federal income tax change, either through a general rate case or through a rulemaking. State ex rel. Utilities Com. v. Nantahala Power & Light Co., 326

N.C. 190, 388 S.E.2d 118 (1990). EDF acknowledges that on January 3, 2018, the Commission opened Docket No. M-100, Sub 148 to address the FTCJA issues.

In its post-hearing Brief, Kroger notes that on December 22, 2017, the FTCJA was signed into law, lowering the Federal corporate income tax rate from 35% to 21%. Kroger states that the Commission noted in its Order initiating proceedings in Docket No. M-100, Sub 148, that the reduction in the corporate income tax rate will have an immediate and favorable impact on the cost of providing services to utility customers, including the customers of DEP. Kroger contends that income taxes are a cost of service for ratemaking, and that when tax expense goes down so too should rates. Kroger urges the Commission to recognize the impact of the new tax rate in this proceeding by lowering customer rates commensurate with DEP's reduced tax expense.

On January 3, 2018, the Commission issued an Order in Docket No. M-100, Sub 148 initiating an inquiry into the effects of the FTCJA. The Commission's Order included notice to affected utilities that effective January 1, 2018, the Federal corporate income tax expense component of all existing rates and charges will be billed and collected on a provisional rate basis. Therefore, the Commission will address the effects of the FTCJA in Docket No. M-100, Sub 148.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 69-71

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

The Company presented Settlement Exhibit 1, Schedule 1 and Updated Bateman Exhibit 1 – Partial Settlement reflecting DEP's revised requested increase incorporating the provisions of the Stipulation, the Company's position on the unresolved issues and the impact of the EDIT decrement rider. Per those exhibits, the resulting proposed revenue requirement of the Company is $305,955,000. Second Revised Settlement Exhibit 1, Schedule 1 shows the Public Staff's revised recommended increase incorporating the provisions of the Stipulation, the impact of the EDIT decrement rider and its adjustments (Coal Ash, Storm Costs) reflecting the Public Staff's position on the Unresolved Issues. The resulting proposed revenue requirement by the Public Staff is $99,726,000.

As discussed in the body of this Order, the Commission approves the Stipulation in its entirety and makes its individual rulings on the unresolved issues as discussed. Due to the intricate and complex nature of some of the issues, the Commission requests that DEP recalculate the required annual revenue requirement as consistent with all of the Commission's findings and rulings herein within 10 days of the issuance of this Order. The Commission further orders that DEP work with the Public Staff to verify the accuracy of the recalculations. Once the Commission receives this filing, the Commission will work promptly to verify the calculations and will issue an Order with final revenue requirement numbers.

In addition, the Commission requests that DEP and the Public Staff provide the Commission with the demand and energy allocation factors that they, respectively, deem appropriate for allocating the CAMA costs to the North Carolina retail jurisdiction.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 72

The evidence supporting this finding of fact and conclusion is contained in the Application, the testimony and exhibits of all the witnesses, the Stipulation, and the entire record in this proceeding.

Pursuant to G.S. 62-133(a), the Commission is required to set rates that are "fair both to the public utilities and to the consumer." In order to strike this balance between the utility and its customers, the Commission must consider, among other factors, (1) the utility's reasonable and prudent cost of property used and useful in providing adequate, safe and reliable service to ratepayers, and (2) a rate of return on the utility's rate base that is both fair to ratepayers and provides an opportunity for the utility through sound management to attract sufficient capital to maintain its financial strength. See G.S. 62-133(b). DEP's continued operation as a safe, adequate, and reliable source of electric service for its customers is vitally important to DEP's individual customers, as well as to the communities and businesses served by DEP. DEP presented credible and substantial evidence of its need for increased capital investment to, among other things, maintain and increase the reliability of its system and comply with environmental requirements.

In its Application and testimony, DEP stated that since 2013 it has been adding new gas-fueled generation, along with adding new utility-scale solar facilities, to replace older, less-efficient coal-fired generation. In addition, DEP noted that it began construction on its Asheville Combined Cycle Plant, and has almost completed construction of its new Sutton Blackstart Combustion Turbine. According to DEP, approximately $253 million of its initially requested $477.5 million revenue increase was intended to recover the costs associated with these plant additions and upgrades. In addition, DEP stated that it has started complying with recently adopted federal and state rules regarding the handling of CCRs and closure of CCR basins, and that $66 million of the requested $477.5 million increase was intended to recover ash basin closure compliance costs incurred since January 1, 2015. Further, DEP stated that it was requesting to recover $129 million toward ongoing ash basin closure compliance costs, with any difference from the requested amount and actual costs to be deferred until a future general rate case. DEP stated that the remaining $29 million of the requested rate increase was intended to recover costs related to tax rate changes, major storm restoration costs, nuclear development costs, and an updated Customer Information System.

These are representative examples of the capital investments that have been made and are planned to be made by DEP in order to continue providing safe, reliable and efficient electric service to its customers.

In addition, the rate increase approved herein is mitigated to some extent by the Partial Settlement Agreement entered into between DEP and the NC Justice Center, wherein DEP agrees to contribute $2.5 million to the Helping Home Fund for low-income energy assistance.

Based on all of the evidence, the Commission finds and concludes that the revenue requirement, rate design and the rates that will result from this Order strike the appropriate balance between the interests of DEP's customers in receiving safe, reliable and efficient electric service at the lowest possible rates, and the interests of DEP in maintaining the Company's financial strength at a level that enables the Company to attract sufficient capital. As a result, the

Commission concludes that the revenue requirement and the rates that will result from that revenue requirement established as a result of this Order are just and reasonable under the requirements of G.S. 62-30, et seq.

IT IS, THEREFORE, ORDERED as follows:

1. That the Stipulation filed by DEP and the Public Staff is hereby approved in its entirety.

2. That DEP is entitled to recover the actual coal ash basin closure costs DEP has incurred (netted against the amount already included in the Company's rates following its last rate case) during the period from January 1, 2015 through August 31, 2017, less a disallowance of $9.5 million, for a total amount to $232,390,000, to be adjusted based on the allocation factors to be provided by DEP and the Public Staff pursuant to Ordering Paragraph No. 5. These costs shall be amortized over a five-year period, with a return on the unamortized balance and then reducing the resulting annual revenue requirement by $6 million for each of the five years.

3. That DEP is authorized to record its September 1, 2017 and future CCR costs in a deferral account until its next general rate case. This deferral account will accrue a return at the overall rate of return approved in this Order.

4. That the appropriate revenue requirement for the first four years shall be reduced by the EDIT Rider decrement of $42.577 million.

5. That DEP shall recalculate and file the annual revenue requirement with the Commission within 10 days of the issuance of this Order, consistent with the findings and conclusions of this Order and the Stipulation. The Company shall work with the Public Staff to verify the accuracy of the filing. DEP shall file schedules (North Carolina Retail Operations – Statement of Rate Base and Rate of Return, Statement of Operating Income, and Statement of Capitalization and Related Costs) summarizing the gross revenue and the rate of return that the Company should have the opportunity to achieve based on the Commission's findings and determinations in this proceeding. In addition, DEP and the Public Staff shall provide the Commission with the demand and energy allocation factors that they, respectively, deem appropriate for allocating the CAMA costs to the North Carolina retail jurisdiction.

6. That DEP is hereby authorized to adjust its rates and charges in accordance with the Stipulation and findings in this Order effective for service rendered on and after the following day after the Commission issues an Order accepting the calculations required by Ordering Paragraph No. 5.

7. That the Commission shall issue an Order approving the final revenue requirement numbers once received from DEP and verified by the Public Staff as soon as practicable.

8. That the three settlement agreements entered into by DEP with Commercial Group, Kroger, and NC Justice Center are in the public interest and should be approved in their entirety.

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

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

11. That the approved base fuel and fuel-related cost factors are as follows (amounts are cents per kWh, excluding regulatory fee): 1.993 for residential customers; 2.088 for SGS customers; 2.431 for MGS customers; 2.253 for LGS customers; and 0.596 for Lighting customers.

12. That the Company shall implement an increment rider, effective on the same date as its new base rates, and expiring at the earlier of (a) January 30, 2020, or the last day of the month in which the Company's actual coal inventory levels return to a 35-day supply for three consecutive months of total coal inventory of 37 days or less, to allow the Company to recover the additional costs of carrying coal inventory in excess of a 35-day supply (priced at $76.11 per ton). The interest on any under- or over-collection shall be set at the Company's net-of-tax overall rate of return. The Company shall adjust the rider annually, concurrently with its DSM/EE, REPS, JAAR and Fuel Adjustment riders.

13. That on or before December 31, 2018, the Company and the Public Staff shall complete an analysis showing the appropriate coal inventory level given market and generation changes since the Company's rate case in Docket No. E-2, Sub 1023.

14. That the Company shall conduct a workshop on its Power/Forward grid investments in the second quarter of 2018.

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

16. That DEP shall not be allowed to defer the costs of the June and July 2016 thunderstorms amounting to $1.720 million in O&M expenses.

17. That DEP shall be, and is hereby, allowed to defer incremental O&M costs of 2016 storms in the total amount of $51.032 million.

18. That DEP is authorized to record the incremental storm cost amortization expense over a five-year period beginning with the month of October 2016.

19. That DEP's request for deferral of the depreciation expense and carrying costs related to the 2016 storms at its weighted average cost of capital on the capital investments, and the carrying costs at its weighted average cost of capital on the deferred costs, shall be, and is hereby, denied.

20. That DEP shall within 30 days of the date of this Order make a $2.5 million contribution from shareholder funds to the Helping Home Fund to be used for low-income energy assistance in DEP's North Carolina service territory.

21. That DEP is allowed to collect in rates a North Carolina retail normalized annual level of storm costs in the amount of $11.018 million.

22. That the Commission's approval in this Order of deferral accounting and other accounting procedures is without prejudice to the right of any party to take issue with the amount of or the accounting treatment accorded these costs in any future regulatory proceeding.

23. That the Company's proposal for a JRR, as modified by this Order, and the JRRR are hereby approved for a one-year pilot with an option to renew it for a second year if the Company provides evidence that the JRR is achieving its intended purpose.

24. That the JRR and JRRR revenues shall be reported to the Commission annually, if the JRR is in effect more than one year, and the JRRR shall be reviewed and will be subject to adjustment annually coincident with DEP's December fuel adjustment to match anticipated recovery revenues and true-up any past over-or under-recovery.

25. That due to the uncertain date of implementation, compliance tariffs shall be filed prior to implementation of the JRRR and customers shall be notified by bill insert or message upon implementation.

26. That within 30 days of this Order, but no later than 10 business days prior to the effective date of the new rates, DEP shall file for Commission approval five copies of all rate schedules designed to comply with this Order, accompanied by calculations showing the revenues that will be produced by the rates for each schedule. This filing shall include a schedule comparing the revenue that was produced by the filed schedules during the test period with the revenue that will be produced under the proposed settlement schedules, and a schedule illustrating the rates of return by class based on the revenues produced by the rates for each schedule.

27. That DEP shall submit a proposed customer notice to the Commission for review and approval, and upon approval of the notice by the Commission, shall give appropriate notice of the approved rate increase by mailing the notice to each of its North Carolina retail customers during the billing cycle following the effective date of the new rates.

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

29. That DEP shall be, and is hereby, authorized to establish a regulatory asset to defer and amortize the costs of its Customer Connect Program (CCP). The regulatory asset account shall accrue AFUDC until the DEP Core Meter-to-Cash release (Releases 5-8) of the CCP project goes into service, or January 1, 2022, whichever is sooner. At that point, the costs will be amortized over 15 years.

30. That DEP shall file reports regarding the development, spending and accomplishments of the CCP each year on December 31 for the next five years, or until the CCP is fully implemented, whichever occurs later. Further, DEP and the Public Staff shall develop a format for the annual CCP report and file the format with the Commission within 90 days of the date of this Order.

31. That DEP shall be, and is hereby, authorized to defer to a regulatory asset account the cost of existing AMR meters replaced by AMI meters. However, the approval granted herein is without prejudice to the right of any person to contest the recovery of the amount of the regulatory asset in future rates, and is without prejudice to the Commission's authority to deny or reduce such recovery if the Commission concludes that DEP has not complied with the Commission's rules or other requirements.

32. That if DEP receives revenue for any deferred cost for a longer period of time than the amortization period approved by the Commission for that deferred cost, the Company shall continue to record all revenue received for that deferred cost in the specific regulatory asset account established for that deferred cost until the Company's next general rate case.

This 23rd day of February, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

Commissioner ToNola D. Brown-Bland dissents in part.
Commissioner Daniel G. Clodfelter concurs in part, and dissents in part.
Commissioner Charlotte A. Mitchell did not participate in this decision.

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

Commissioner ToNola D. Brown-Bland, dissenting in part:

I dissent from the majority opinion with respect to the Findings of Fact 35, 54 and 55 and discussion leading to the determination that the Company is entitled to full recovery of all coal ash expenses subject to a one-time mismanagement penalty. I acknowledge that the penalty imposed represents an attempt to hold the Company accountable for its admitted mismanagement and oversight of its coal ash handling and disposal operations. However, this approach, without further analysis, does not reasonably assure that the rates fixed for the Company's service are "fair to both the public utilit[y] and to the consumer," and that the rate set by the Commission and to be received by the Company is just and reasonable. G.S. 62-133 and 131. It is not fair to burden the consumers with rates that include costs attributable to the Company's imprudence nor is it fair to the Company to disallow recovery of reasonable costs necessary to the provision of adequate, efficient and reasonable service.

Fairness in rate fixing requires the Commission to undertake reasonable effort to examine the incurred costs sought to be recovered and distinguish among such costs to reasonably assure consumers are not burdened with costs that are unfair and the utility Company is not denied recovery of its reasonable costs. In this general rate case at hand, imposition of the penalty alone without analysis of costs to determine why they were incurred does not meet the Commission's duty to fairly balance the interests of the consumer and the Company and to reasonably assure that costs are fairly assigned between the two. A one-time penalty cannot substitute for the Commission's duty to make rates that are fair to both the public utility and the consumer on a case by case basis considering the evidence of record in each case.

While it concluded the Company should face a consequence for its mismanagement, the majority failed to acknowledge that the Company's admission in a court of law to mismanagement of its coal combustion residual activities through inadequate oversight that led to unlawful water pollution is conclusive evidence of its imprudence in handling, storage and management of coal ash. Pleading guilty to unlawful criminal activity, *i.e.*, four counts of criminal negligence resulting in coal ash pollutant discharges to surface waters, established negligence per se and therefore it is appropriate to conclude in the case at hand, where the prudence of the Company's actions is at issue, that the same plea established imprudence per se.[1] Where the Company has pled guilty to criminal negligence a finding that its actions concerning those criminal negligent actions were prudent is contrary to law.

Moreover, the Company's imprudence is also established based on other evidence of record in this case. Even if for the sake of argument, the Company's position is accepted that at all times relevant its coal ash handling practices and actions met the requirements of applicable statutory law and regulations, the evidence, as discussed below, shows that the Company failed in or breached its *legal* duty to exercise the ordinary duty of care to protect life, property and the environment from harm and unreasonable risks in the performance of its lawful activities and business obligation to properly handle, store and manage coal ash laden with heavy metals and other contaminants. This ordinary duty of care (and it could be argued the Company has a higher duty stemming from the nature of electric generation and related coal combustion activities) exists at all times and, unless otherwise stated expressly by statute, is not excused by mere compliance with statutes and regulations. Despite its recognition that its guilty plea in federal court was acknowledgement of failure to live up to its own standards, the Company seems to toss aside its ever present duty of care and argue its only duty is compliance with statutes and regulation. It seems to further argue that any action or costs beyond bare compliance would be wrong or considered gold plating by this

[1] Violations of statutes which have the purpose of protecting the public from harm to life or safety constitute negligence per se. See Bell v Page, 271 N.C. 396, 156 S.E.2d 711 (1967); Hampton v. Spindale, 210 N.C. 546, 187 S.E. 775 (1936).

Commission.[1] Yet the Company's own testimony of record shows that it knows better. Company witness Wells testified that in 2006 DEP began groundwater monitoring activities related to its ash facilities without being required to do so by any law or regulation. It is reasonable to infer the Company knew or intuitively recognized in 2006 that it had a duty of care to monitor the groundwater as part of basic safety and environmental protection obligations that could not be delayed due to cost recovery concerns. Actors such as the Company cannot avoid the basic duty of ordinary care to take steps to protect others from unreasonable risks or harm based on concerns that cost recovery from this Commission or any other agency may be denied. Therefore, the applicable standard of care for the Company is not only compliance with statutes and regulations but also compliance with the legal duty of ordinary care as discussed above. Where, as here and as will be discussed below, the evidence of record establishes both that the Company breached this duty and that certain incurred costs were caused as a result of such breach, the majority's finding that incurring those identified costs was reasonable and prudent is contrary to law.

The evidence of record generally shows that around the 1920s when the Company began providing electric service in our state, it did so by generating electricity through the combustion of coal. The generation process created the byproduct of coal ash. At the time, neither the use of fossil fuel in power generation nor the ash byproduct were known to be particularly harmful to human well-being or the environment. Nevertheless, the ash resulting from the generation process was substantial and the Company as part of its provision of service undertook the obligation to properly manage it. It is presumed that during this time period, the rates approved by the Commission and paid by ratepayers were adequate to compensate the Company for its costs for its proper management of the coal ash byproduct. The part of the ash that did not fly into the atmosphere through smokestacks was collected by the Company from the bottom of boilers and placed in on-site storage areas. Before there were ash basins or landfills, the bottom ash would have been placed in a lay of the land area. This could have created a pile on-site or just filled in a low area.

Neither the creation nor management of the ash in this manner was negligent based on the then current knowledge and foreseeability of the risks at that time. In choosing fossil fuel generation, the Company complied with the state's policy of providing service at the least cost and the consumers benefitted from this choice at least in the form of low electric rates for decades down to the present. Storing the dry ash on-site was not negligent as the scientific and healthcare communities had not determined that such disposal could pose a substantial risk of harm to people or the environment and the environmental risks of harm or injury from coal ash management practices were not then foreseeable by the Company. This method of storage also complied with the state's least cost policy from which consumers benefitted in the form of low electric rates.

In the 1950s, the Company, in alignment with the power industry at the time, created unlined basins and ponds to serve as repositories for coal ash sluiced out of boilers using water. The Company's repositories were created on-site with the generation plants from the mid-1950s through 1985. When this practice began in the 1950s, unlined basins were the primary technology for treating and handling coal ash throughout the country. There were no governmental regulations requiring that the ash repositories be lined for safety or health reasons and the scientific and

[1] The gold plating argument is a convenient one and may have been more convincing if the Company had presented a plan to improve its coal ash management safety and compliance practices to the Commission and had shared what it learned from the Sutton report as will be discussed herein.

healthcare communities still had not formed a certain opinion as to the risk of harm posed by unlined ash basins and ponds. The evidence before the Commission does not establish that the Company knew or reasonably foresaw that its coal ash handling practices were problematic or harmful to human life or the environment. Neither our state nor our nation was particularly environmentally aware or concerned with the harmful implications of coal ash management practices before around the time the United States Environmental Protection Agency (EPA) was established in 1970. Thus, it remained true that neither the ash created up through this time nor the Company's early coal ash management activities, including treatment of wet ash in unlined repositories, was imprudent. Fossil fuel generation and wet coal ash treatment in unlined basins and ponds was also compliant with the state policy that electric service be provided for the least cost and consumers continued to benefit in the form of low electric rates. Again, it is presumed that during this time period, the rates paid by ratepayers were adequate to compensate the Company for its costs for its proper handling and disposal of the coal ash.

By 1972, the EPA had begun to regulate unlined coal ash basins under the Clean Water Act and set groundwater standards for industry and water quality standards for contaminants in surface waters. The federal regulation of ash basins was clear indication to power generators like the Company that coal ash was being examined as posing a threat to ground and surface water. By 1979, the State of North Carolina's environmental regulator (today known as DEQ) implemented what is known as the 2L water regulations. Since 1983, these rules required persons including the Company to take actions both to prevent and correct groundwater contamination. By 1988, as reported publicly by the EPA in its report to Congress on wastes from power plant combustion of coal, 40% of generating units built after 1975 used lined ash disposal facilities. The EPA began regulating coal combustion waste under the Resource Conservation and Recovery Act in 2000. In 2008, a huge spill of over 5 million cubic yards of coal ash occurred at the Tennessee Valley Authority Kingston Fossil Plant, which resulted in ash being released into the Emory River. That spill caused both the industry and the EPA to focus more on, among other related issues, understanding the threat posed by unlined coal ash basins to surface and ground water. By 2010, the EPA had developed and issued proposed rules regarding Coal Combustion Residuals (CCR Rules) and had begun the process of receiving comments from interested parties, including power producers.

Thus, the evidence shows the Company had known for about 30 years prior to enactment of the North Carolina Coal Ash Management Act (CAMA) that the state's 2L water regulations required it to prevent and to correct exactly the kind of pollution which the Company admitted through its guilty plea it negligently allowed to occur from at least 2010 through 2014. The TVA incident combined with the regulatory response and the participation of the industry, including the Company, in the EPA rulemaking process informed or should have informed the Company, by 2010 and well before the 2014 enactment of CAMA, of the gravity of the situation surrounding the proper management of coal ash, which was continuing to mount as coal continued to be used in the generation process to meet customer demand for electric power. With knowledge of the foregoing regulatory efforts and requirements as well as the spill incident, the Company certainly had a clear obligation, by 2010 if not sooner, in the exercise of due care to monitor its repositories and take action upon any evidence that the repositories were not containing the coal ash in the intended and required manner. That is to say, that between the TVA spill in 2008 and 2010, by keeping abreast of EPA activities related to the spill including developing the CCR Rules, and through its knowledge of the state requirements making it unlawful to exceed established groundwater contamination levels, the Company knew the concerns and risks associated with coal ash contamination. It is reasonable to infer from the evidence that the Company was aware that it ran the risk of its unlined ash containment repositories failing to contain and that such failure would likely result in unlawful water contamination. It is against the weight of the evidence to infer that the Company was unaware of these risks.

In fact, the evidence further establishes that well prior to the notable and historical TVA spill and the 2014 release of ash into the Dan River from Duke Energy Carolinas' Dan River Steam Station, DEP had actual knowledge that its own ash basins at the Sutton and Asheville plants were not serving their essential purpose of effectively treating and containing ash—at least not at the level that was reasonably expected or required by the Company's duty to exercise due care in coal ash management activities. The National Pollution Discharge Elimination System (NPDES) permitting system, adopted in 1972 with permitting authority granted to North Carolina in 1974, implements standards under the federal Clean Water Act for preventing pollutants from being discharged into surface waters. Similarly, North Carolina's 2L standards were adopted in 1979 to set limits on harmful groundwater pollutants and to require corrective action when pollution occurs. First the evidence is that there were a number of NPDES permit violations and unlawful groundwater exceedances at DEP coal-fired plant sites, including the Sutton and Asheville plants, going back at least 10 years, *i.e*, as far back 2007. The Company knew of the 2007 violations and exceedances when they were noticed by DEQ in 2007. Indeed, DEP witness Wells testified that since 2010 DEP has been attempting to persuade DEQ to issue NPDES permits authorizing DEP's seeps, but DEQ has thus far chosen not to permit them.

Aside from whatever the status of the evolution of ash regulation may have been, upon learning that seeps and exceedances were attributable to its unlined ash ponds and basins, the Company's duty of ordinary care required it to take timely steps to manage its ash *i.e.*, by properly maintaining its water treatment equipment or by removing ash from unlined ponds and placing it in properly lined repositories. Not taking such steps to arrest the seeps and exceedances for more than seven years while waiting for DEQ to act on the Company's request to approve and permit the seeps was not reasonable. It was a breach of the Company's duty of care and imprudent.

The Company's knowledge of the inadequacy of its coal ash management practices is further documented by its own L.V. Sutton Steam Electric Plant long term ash strategy study phase report (Sutton report) produced in November 2004 by the engineers of the Company's fossil generation department.[1] The report provides substantial and convincing evidence that the Company knew its unlined ash ponds were not in compliance with applicable coal ash regulations and posed a risk of failing to contain the ash contaminants. The report put forth for consideration a number of alternatives for handling ash at the Sutton plant because of then present and foreseeable issues with two Sutton ash ponds. The existing 1984 ash pond was predicted to be out of capacity for any future ash storage by June 2006 based on the ash production levels occurring at the time. The 1983 pond was unlined and viewed by the Company's engineers not to meet current ash management compliance requirements. In addition, the study examined and addressed another unlined disposal site on the Sutton property that was used when the plant first went in service, but

[1] Attorney General's Office —Wells Cross Exhibit 3

that had not been studied to determine the extent of any issues it posed and "ha[d] not been high on the EPA's radar."[1]

A cross-disciplinary Company team, that included, among others, representatives from Fossil Generation Department East Region Engineering, Technical Services Department Ash Management, Total Suspended Solids Environmental Section, The Treasury Department and <u>two</u> contract engineering firms, recommended that the Company take steps toward a solution that would accommodate "all of the plant's previous ash production from both the 1983 and 1984 ash ponds and the pre-ash pond disposal site" that would "allow for construction to begin no later than January 2006 to support the 1984 ash pond end of life" forecasted to be June 2006. The solution that the Company team of engineering and environmental experts recommended was the development and construction of an Industrial Park. The study team noted "this option would eliminate the need for the two associated projects of relining [with a compliant liner] the 1983 ash pond and the remediation of the pre-ash pond disposal site." It was further noted that the fastest possible construction for such an Industrial Park would be 3 years, *including "the moving of the ash from the existing sites."* Thus, in addition, the Sutton report identified a contingency plan being implemented for a vertical dike extension to allow the plant to continue to generate electricity for the next 5 to 7 years.

Statements contained in the Sutton report demonstrate that as of 2004, contrary to claims that the Company was always in full compliance with existing regulation, the Company was aware that its unlined ponds were not in compliance with the current regulatory standards and posed contamination risks. In discussion of the 1983 unlined pond, the report contains the following:

> The first issue is that the 1983 ash pond was constructed during a period when it was not required to provide a non-permeable liner, and was constructed with the native sandy soils. This pond has been functionally full since 1983, but is still permitted, and is occasionally used when there are issues requiring the 1984 pond to be temporarily dry. The current environmental atmosphere is that these ponds will eventually have to [sic] emptied and *placed in a lined containment to eliminate the leaching of the ash products into the ground water system.* This is an issue that is not currently being pressed, but it is anticipated that with the tighter environmental conditions it will soon become an emergent issue. This issue is aggravated by the fact that a test monitoring well located 300' from edge of the 1983 ash pond has shown high levels of arsenic during the past two quarterly tests. *This may or may not be related to the unlined ash pond.* A recent study by an independent firm indicated this concern may be less than originally thought. *It could be mitigated* by adding monitoring wells to the NPDES permit, *but could still pose an issue in the future.* [All italics added.]

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[1] Although this site contained as much or more ash as the 1983 pond, which was functionally full, and had once been designated a Superfund site, it appears from the report that the Company had not cleaned it up or taken any action to remediate apparently because the environmental regulators had not pushed it to do so. Again, regulator inaction or leniency does not relieve an actor like the Company from its ordinary duty of care to prevent or stop a harmful situation it created in the performance of its business activities.

Sutton Report, p. 2. The language in the quoted passage reveals that the company engineers knew at the time of the report that the days when unlined ash ponds were allowed were in the past; that unlined ponds allowed leaching of ash products into ground water and that the purpose of a non-permeable liner was to "eliminate" such leaching; that the 1983 pond could possibly be leaching arsenic; and that even if the arsenic situation were mitigated, it could still pose an issue in the future, making mitigation an insufficient remedy. Thus, the Company and its engineers knew in 2004 that its unlined ash ponds posed a risk of coal ash contaminants leaching into ground water and that one way to stop and effectively remedy that risk or any actual leaching was to place the contents of unlined ponds into lined containment facilities.

The fact that the engineers were not certain at the time of the internal publication of their report whether the 1983 pond was leaching arsenic does not negate their actual knowledge that the pond might have been leaching and could pose a future issue regardless. While the report shows that Company engineers attempted to redress the capacity problems with temporary solutions based on maintaining existing discharge permits and were willing to consider adding additional monitoring wells to perhaps mitigate leaching issues, taken as a whole it nonetheless also indicates that these solutions were viewed only as short term fixes. The report demonstrates that the engineers recognized and recommended that the situation called for a long-term permanent solution to meet the already then current requirement to contain leachate and prevent and remediate water contamination. Having an active discharge permit for a non- compliant containment does not equate with compliance with ash pond or coal combustion residuals regulations.[1]

Additional statements from the 2004 report also show that the Company knew its unlined containment ponds were non-compliant with the then current regulations. As part of the discussion of the alternative of doing nothing to address the containment issuesat Sutton, the report states, "It is assumed that the North Carolina Division of Water Quality (NCDWQ) [as part of its 'increased emphasis on ash ponds and their [e]ffects on the surrounding area and groundwater'] will require the 1983 ash pond to be emptied and lined to comply with *current* ash pond regulations." (Emphasis added.) Translation: At the time the report was written in 2004, the 1983 ash pond did not comply with the current ash pond regulations.

In discussion of other various new pond alternatives, the report states, "The new ash pond would be constructed with the current liner requirements including an impermeable liner with leak detection and monitoring system." This is further evidence the Company knew that to make its unlined repositories compliant with the regulations of 2004, impermeable liners would need to be installed to assure adequate containment of ash waste. Regarding new ponds or alternatives that would allow the 1983 and 1984 ponds to extend capacity for a few years and/or to combine capacity extension with beneficial use projects, the report points out that such solutions would not alleviate the need to line the 1983 ash pond or to have to remediate the pre-ash pond disposal site by 2019. The same was noted in the report with respect to an alternative that called for ash from the 1984 pond to be shipped to other non-plant site locations. In contrast, the report noted three

[1] In the Sutton report, the Company engineers were addressing two distinct problems: 1) maintaining pond discharge permits in order to keep the Sutton plant operating and 2) developing and making ash containment facilities that would comply with ash management regulations. An active discharge permit for a non-compliant ash pond was a measure the engineers recognized as affording the Company time to remedy non-compliance with a permanent solution like a new lined pond or an industrial park that would accommodate all of the Sutton ash as ground fill.

other alternatives, including the industrial park alternative recommended by the engineers, would accommodate all the ash from the two ponds and the pre-ash pond disposal site and eliminate the need to line the 1983 pond and to remediate the pre-ash pond disposal site. The report leaves no doubt that Company engineers knew and advised the Company in 2004 that the old unlined pond was non-compliant, that in any scenario where the pond remained in use, the Company could not escape the requirement to line the pond with a non-permeable liner, and that the Company would in a short time be faced with stricter enforcement of compliance standards by the environmental regulators.

In sum, the 2004 Sutton report is evidence that the Company's own in-house and outside contract engineers put the Company on notice that its unlined (not lined with a non-permeable liner) ash ponds were not compliant with the environmental regulations of the day; that the unlined ponds were subject to leaching of their contents and that ash from at least one unlined Company pond might already be leaching into the groundwater; and that the Company had available to it a number of specific alternative actions that represented reasonable optional pathways to coal ash management compliance. Having this knowledge in 2004 but failing to take timely and appropriate action to bring its unlined ponds into compliance to stop and/or prevent leaching of contaminants into groundwater was at a minimum, whether held accountable by federal and state regulators or not, a breach of the Company's duty to exercise due care in its ash management activities. This failure was both negligent and imprudent.

Because as discussed above, the greater weight of the evidence supports a finding that the Company was negligent and imprudent in its coal ash management by failing to act in a timely and appropriate manner based on information contained in the Sutton report, as well as its NPDES permit and 2L violations, the Commission, in setting just and reasonable rates in the public interest, must examine the coal ash management costs that the Company seeks to recover in the case at hand to determine whether the costs are a result of the Company's imprudence. If the evidence supports a finding that specific costs were incurred by the Company due to the Company's own imprudence, then those costs would have been imprudently incurred. It would be unfair and not in the public interest for the Commission to set rates that are based upon allowing the Company to recover costs attributable to the Company's imprudence. Such rates would not be just and reasonable. On the other hand, if the evidence is insufficient to establish that particular coal ash management costs resulted from the Company's imprudence and those costs were otherwise prudently incurred to comply with current legal requirements, to disallow recovery of those prudent costs would be unfair and not in the public interest of maintaining adequate, reliable and economical electrical service at just and reasonable rates.

The coal ash management costs incurred to date by the Company to comply with the state CAMA legislation and the federal CCR Rule enacted and promulgated respectively in 2014 and 2015 to specify the way coal ash must be handled and stored going forward pertain to ash previously accumulated and treated in unlined basins and ponds. As discussed above, the creation or production of the ash was not unlawful or negligent and ratepayers have enjoyed the benefits of a least cost electric generation process which yielded coal ash as a waste byproduct. The Company's imprudence or negligence in the manner it handled or managed the ash byproduct did nothing to change the existence of the tons of accumulated ash or to require the present need to have this ash properly managed and in accordance with applicable law. With or without the Company's admitted negligence or its imprudence as supported by other evidence discussed hereinabove, the Company would be required to do whatever is reasonably necessary not only to comply with current applicable law but also to manage all existing and stored ash with due care to avoid the unreasonable risk of harm to persons, property and the environment. The heightened standards for coal ash management mandated by the changes in federal and state law under the CCR Rule and CAMA, as with any governmental action, are beyond the control of the Company. The Company has no choice but to comply with such new requirements, notwithstanding the Company's compliance with the prior law, and is expected to so comply as part of its ongoing certificated franchise to provide electric service. If twenty years from now the standards for ash management were to change yet again, the Company at that time would still have no choice but to comply and the costs incurred to take reasonable compliance actions relative to the very same ash being moved and stored today would then be appropriate to be recovered from ratepayers in electric service rates.

To state it another way, even in the case at hand where the evidence establishes that the Company was imprudent in its handling of coal ash, the Company's imprudence did not cause or change the fact that all of the coal ash at issue exists today and would be subject to new environmental and safety requirements. Moreover, with or without passage of CAMA, the Company would still be legally required to prudently manage its existing as well as its hereafter created ash. Based on current federal law, the technology known today and as logically follows from information and discussion in the Sutton report, such prudent handling would without a doubt require utilizing all three compliance mechanisms of making beneficial use of accumulated ash, using cap in place techniques, where appropriate and legally permissible, and moving of some substantial amount of stored coal ash from unlined to lined facilities.[1] CAMA did not change the accepted methods for proper management of coal ash; rather it incorporated those known methods into law. As the Company has known at least since the 2004 Sutton report and well before CAMA, it was going to have to remove ash from non-compliant unlined repositories. The removed ash would have to be put to beneficial use or placed in an acceptably lined facility and monitored for containment unless and until it was determined that the ash no longer posed a threat of harm. Therefore, in this case and going forward, the Company is fairly entitled to recover all the costs it has incurred to cap in place where appropriate under current law and to engineer and construct new lined containment facilities as well as to dewater, excavate and re-store pre-2007 ash production from unlined facilities into lined repositories.

However, as to ash first placed in unlined repositories beginning in 2007 and after, the Company is fairly entitled to recover costs that would be reasonable to implement on- site lined repositories or costs necessary to cap such ash in place. Dewatering, excavation and the "re-placement" costs of putting this ash that was produced in or after 2007 in new repositories (whether on or off-site) are not recoverable. If the Company had acted prudently by developing and implementing plans for compliant storage of ash within a reasonable time following completion of the Sutton report in November of 2004, evidence in the record establishes that it could have completed compliant on-site landfill repositories within 18 months. As Company witness Wells duly noted there can be unexpected delays in the permitting and construction process. Therefore, allowing the Company at least 24 months (from December 2004 to January 2007) to construct and

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[1] The five ash basins at Cape Fear are not subject to the CCR Rule given certain exclusions in the Rule. Three of the basins at H.F. Lee are excluded from the federal CCR Rule as well.

deploy compliant ash repositories is reasonable and would mean that by 2007, all ash produced during or after 2007 should have and could have been managed through direct one-time placement into lined repositories; there should never have been any need to dewater, excavate and "re-place" the 2007 and post 2007 ash. Thus, the Company's reasonable costs for ash first produced in 2007 and after are only those costs for engineering and constructing the necessary lined facilities and for the ongoing costs of storing and monitoring of the ash once in the new compliant repositories. This ash should have gone from production and collection directly into compliant repositories without needing to be handled a second time and placed into a second repository. The rates previously collected from the ratepayers presumably would have paid for this initial ash handling just as they paid for the ash when it was first placed in the non-compliant unlined basins and ponds. It follows that dewatering and excavation costs for the tons of ash created from 2007 and after would not have been incurred except for the Company's ash mismanagement and negligence, resulting in the need to handle the ash a second time.[1] The engineering, construction and continued storage and monitoring costs areallowable for recovery because these costs were not created by the Company's imprudence, would have been incurred as proper ash management costs without regard to the Company's failure to act sooner to place the ash in an appropriately lined facility as required by due care and current regulation, and have not been previously paid for by the ratepayers.[2]

In addition to the engineering, construction, dewatering, excavation, storage and monitoring costs discussed above, the Company seeks to recover all the transportation costs (minus $9.5 million to transport ash from the Asheville plant, which the Company agreed was reasonable to question) it has incurred to date to truck or haul coal ash from its Sutton and Asheville plants' on-site repositories to off-site locations. The Company should not be entitled to recover these transportation costs (pre-2007 ash nor 2007 and after ash) from the ratepayers because they flow directly from the Company's negligence in its coal ash management and its failure to use reasonable due care to protect life, property and the environment from harm after it knew or should have known that coal ash posed a serious risk of contamination of surface and groundwater and after it knew or reasonably should have known that its repositories were not adequately containing the ash contaminants. Whether CAMA led to the Company's reasoned perception and judgment that it needed to incur trucking, hauling and preparation-to-haul expenses in order to comply with timeline requirements in CAMA, there nevertheless would not have been any or hardly any transportation costs at all if the Company had not mismanaged its coal ash management obligations and negligently failed to take action to move all ash to on-site lined repositories at the Sutton and

[1] While it may be that the total coal ash management costs sought to be recovered may have been less had the Company not negligently delayed converting to lined ash ponds after the Sutton report was completed, the evidence in the record is that it is nearly impossible and probably highly speculative to determine how much less given the passage of time and a number of other complexities and unknowns. Nevertheless all existing ash is subject to the legal requirement that it be properly stored under the provisions of the CCR Rule and CAMA. The heightened handling and storage standards imposed by law and regulation are for the public benefit and are in the public interest. In balancing the interests of consumers and the utility, I find that rates including the reasonable cost of proper containment of ash but excluding dewatering and moving costs associated with ash created in or after 2007 and further excluding transportation costs (as will be discussed in the following paragraph) is just and reasonable. Such rates fairly balance the consumer's and the utility's interests considering the benefits received and the costs reasonably incurred to properly store and manage ash in accordance with new lawfully imposed standards.

[2] The Company and the Public Staff would be charged with assuring that the ratepayers are not charged twice for the same handling and management costs with respect to the ash produced during or after 2007.

Asheville plants when it knew the ash contaminants were not being adequately contained within the repositories and that unlawful and/or violative discharges and exceedances from the repositories that could impact both surface and groundwater were occurring. Looking at the situation as it existed in 2004, the Company should not have been paralyzed and unable to take reasonable actions to move toward compliant containment of accumulated ash and ash being produced at the time by the fact that environmental regulators had not yet created the specific guidance such as that later found in the CCR Rule and CAMA legislation.

As previously discussed, the Company acted imprudently not to have taken steps after learning of the information in the Sutton report in 2004 and not being prepared to move all pre-2007 ash from unlined repositories at least starting by 2007. Moreover, in 2007, the Company had knowledge that some of its unlined facilities were experiencing exceedances and that the Company was knowingly incorporating the use of unpermitted seeps into its coal ash management practices. If the Company had acted prudently to be in a position to have begun dewatering, excavating and moving pre-2007 ash into lined on-site plant landfills by 2007, it would have been "CAMA compliant" at least with respect to its active basins and ponds before the enactment of CAMA.[1] As explained by Public Staff witnesses Garrett and Moore, on-site remediation is generally the most cost- effective closure method and would certainly not be as costly as securing other locations and transporting off-site to those locations. (Tr. Vol. 18, p. 140.) Timely development and use of compliant on-site landfills beginning around 2007 would have completely eliminated the need for the transportation and hauling costs (for both pre-2007 ash and 2007 and after ash) that the Company found necessary to meet compliance timelines contained in CAMA.[2] In my view it is not necessary to determine whether the Public Staff's witnesses are correct that compliance with CAMA did not necessitate transportation or hauling of ash or that the hauling costs should have been less in order to determine from the greater weight of the evidence in the record that the transportation costs (not to be conflated with dewatering and excavation costs as discussed above) were caused by the Company's imprudence, i.e., mismanagement and negligence,[3] in delaying action to correct the issues identified in 2004.

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[1] Costs related to inactive basins are not part of the costs sought in this case and I am not addressing what would have been reasonable for management of inactive repositories during the 2004 to 2007 timeframe.

[2] There is disputed testimony in the record on whether an on-site landfill could have been constructed at the Asheville plant due to the provisions of the Mountain Energy Act of 2015. If the Company had acted prudently by 2007 to create a compliant on-site landfill at the Asheville plant, the landfill would have been completed prior to enactment of the MEA. The new units contemplated by the MEA would have been planned around the newly constructed basin—not the other way around.

[3] CAMA left the choices and decisions of how best to achieve compliance in a timely manner to the plant/basin owner. I do not take issue with the Company's decision to transport and store ash off-site for compliance purposes, as generally the Commission should avoid substituting its judgment for the Company's business judgment. It is accepted that the Company had several possible workable options to choose from in deciding how best to comply with CAMA and that the Company chose the option[s] it found most appropriate considering a host of information available and pertinent to it at the time. I do not believe the Company chose to haul ash over public roads, creating greater risk of exposure to liability, on the hope of receiving some level of return on any additional expense incurred to do so.

Having determined which costs should be recoverable in rates and which should not, I would allow the recoverable portion to be amortized over seven years (as an unusual or extraordinary expense), with the unamortized balance included in rate base.

/s/ ToNola D. Brown-Bland
Commissioner ToNola D. Brown-Bland

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

Commissioner Daniel G. Clodfelter, concurring in part and dissenting in part:

I. MATTERS ADDRESSED IN THE PARTIAL JOINT STIPULATION

With respect to those matters addressed by the partial joint stipulation negotiated between the Company and the Public Staff, I am in substantial agreement with the majority's disposition of those items. I write separately with respect to the topics addressed by the partial joint stipulation for two reasons. First, there is one matter as to which I would reach a different result than the stipulating parties and the Commission majority. Second, because the partial stipulation deals with some topics only in a conditional, preliminary, or contingent manner, or because they are resolved by the stipulating parties for purposes of settlement of this case only and without prejudice to positions that may be asserted in future cases, I wish to offer my own individual views as a supplement to the majority's analysis, in the hope that such insight may be useful to the parties in future cases.

A. Cost Allocation and Cost of Service

As the Commission majority notes, for the allocation of demand-related costs, the historical position of the Public Staff has been to support the use of the Summer/Winter Peak and Average (SWPA) methodology. This position has been favored by the Commission itself in prior general rate cases. See, e.g., Order Granting General Rate Increase, Docket No. E-2, Sub 1023 (May 30, 2013); Order Assessing Rate of Return Penalty and Granting Partial Increase in Rates, Docket No. E-2, Sub 444 (September 24, 1982). In the partial stipulation in this case, as in the Company's prior 2013 general rate case, the Public Staff has agreed – for purposes of settlement of this case only – not to object to the use of the Summer Coincident Peak (SCP) methodology for allocation of demand-related costs. The stated rationale for this acquiescence is that the Public Staff has concluded that, in the present case, the two different methodologies do not yield materially different results. (Tr. Vol. 19, p. 97; Public Staff Floyd's Late-Filed Ex. 1.) One might well ask why this fact is not instead a good rationale for insisting on the historic preference for the SWPA methodology. The answer lies, of course, in the fact that other stipulating parties and several of the intervenors do not support the SWPA methodology. Neither, though, do they all concur in the use of the SCP methodology, with some parties advocating for the use of a Winter Coincident Peak

(WCP) method or even consideration of a dual Summer-Winter Coincident Peak method. In the resulting negotiations, it appears that the SCP method provided a point of agreement among the greatest number of the parties. Underlying the parties' differences are divergent views about the implications of two factors -- the Company's transition from summer planning to winter planning for resource development purposes and the developing evidence of a shift in the Company's peak loading from summer to winter. These trends appear likely to continue, and the Company, the Public Staff, and other parties may benefit from more explicit direction and guidance from the Commission as to its preferred methodology for allocation of demand-related costs. I would hope that the rationale for supporting one methodology over another can receive more attention in the Company's next general rate case. To that end, I would modify ordering paragraph 28 of the Commission's order to require that the Company, in its annual cost of service filings, include an allocation based on the WCP method, as well as the SWPA and the SCP methods.

The second topic concerns the methodology for apportioning distribution system costs among different customer classes, a subject that indirectly enters into rate design as one of the considerations in setting the basic or fixed customer charge component of billing. Several intervenor parties presented testimony highly critical of the Company's method of implementing its minimum system methodology for apportioning distribution system costs, calling into question, among other things, differences in the outcome of the Company's application of that method and the outcomes achieved by other integrated, investor-owned electric utility companies employing the same method. The testimony of witness Barnes was particularly focused on this discrepancy. (Tr. Vol. 16, pp. 57-67.) The Company's rebuttal testimony did not respond in detail to these criticisms.

In evaluating the Company's use of the minimum system method for allocating distribution related costs, I believe it is also important to recognize that the Company's substantial projected investments in its Power/Forward Carolinas grid modernization program means that distribution system cost allocation among customer classes will take on heightened importance in future rate cases. If the Company is using a suboptimal methodology for allocating these costs or is incorrectly applying an otherwise acceptable methodology, the follow-on implications for rate design could be very significant in the future. For this reason, as in the case of the methodology for allocating demand-related costs, I again believe that the Commission, the Public Staff, and all other interested parties would benefit from a more focused and explicit evaluation of optional methods for distribution system cost allocation and an assessment of the extent to which any single allocation methodology is being consistently applied by the utilities using it.

In summary, I believe that changing trends in resource planning and resource demands plus a planned major reconstruction of the Company's distribution system combine to warrant a more formal examination and expression of Commission policies with respect to matters of cost allocation. Continuing to leave those matters to stipulated settlement on a case-by-case basis risks uncertainty for the Company and its customers, as well as inconsistencies in the application of cost allocation principles among the various regulated utilities. While the technical workshop on grid modernization the Company has committed to conduct in Paragraph IV.A. of the partial joint stipulation will be a useful first step in fleshing out some of the questions about cost allocation that may be generated by the Company's proposed distribution system investments, I am doubtful that the workshop will by itself provide sufficient opportunity to explore in depth many of the issues that surfaced in the testimony of witnesses Simpson, Barnes, Golin, Alvarez, and O'Donnell. The Commission majority has for now reserved judgment on whether to initiate a separate docket on the Company's grid modernization plans; I anticipate that question will be before the Commission again after the technical workshop.

B. Per Customer Fixed Charge

The point just made is one part of the reason I would refuse to accept Paragraph IV.F.3.a. of the partial joint stipulation, and would instead decline to authorize any increase in the per customer fixed charge at this time. The case for exercising caution in increasing the fixed portion of customer charges is well set out in Resolution 2015-1 adopted by the National Association of State Utility Customer Advocates (NASUCA), and I will not repeat here the considerations identified and expressed in NASUCA's resolution. (Ex. Vol. 19, pp. 286-289.) Certain additional factors counsel the same caution in this case. Until there is greater clarity as to how the Company's planned grid modernization investments will affect distribution system costs, it would be premature, I think, toassess how, if at all, the fixed customer charge should be changed. Leading me to the same conclusion, Company witness Wheeler testified that it is his expectation that implementation of the Company's proposed AMI metering system, when combined with the greater flexibility and data management capabilities of the Company's new customer information and billing system, will open opportunities for new and more creative rate designs. (Tr. Vol. 10, pp. 225-228.) In my view, these opportunities should include, among others, ways to address internal subsidization within the residential rate class between low- and high-usage customers, a better method for recovering distribution related costs from net metered customers, and ways to provide additional relief and support for customers who have difficulty paying their bills.

As for this last group of customers, I note that while the partial stipulation between the Company and the North Carolina Justice Center provides for an additional contribution of $2.5 million by the Company to the Helping Home Fund (Fund) for low- income customers. While this is commendable and something I support, mechanisms such as the Fund are imperfect and are not the most desirable means for addressing the impact of electricity cost increases on low-income customers. Innovative rate designs made possible by the Company's deployment of AMI and new customer information and billing systems could be of wider and more sustained benefit to this particular customer group. They could present opportunities for the Company to consider programs similar to the Percentage of Payment Plan and the Residential Service Low Income rate offered by the Company's Duke Energy Ohio affiliate. Again, given the expectation that these developments may or will affect the setting of the per customer fixed charge, I would support deferring any decision to allow a change to the basic customer charge at this time.

II. COAL COMBUSTION WASTES – GENERAL MATTERS

The Company's request to recover costs incurred since 2015 associated with permanent disposal of coal combustion residuals located in nineteen active or inactive surface impoundments at the Company's eight coal-fired plants in North and South Carolina, and to include ongoing and future costs of disposal in its present retail rates, presents a host of difficult questions, many of which have been only infrequently addressed, if at all, in prior rate cases.[1] The Commission has in past cases addressed the recovery in rates for utility investments in abandoned or cancelled generating plants. See, e.g., State ex rel. Utilities Comm'n. v. Thornburg, 325 N.C. 463, 385 S.E.2d 451 (1989) (Thornburg I); State ex rel. Utilities Comm'n. v. Thornburg, 325 N.C. 484, 385 S.E.2d 463 (1989) (Thornburg II). However, the matters at issue in this case differ from such investments in that they involve present and future expenditures incurred and to be incurred to dispose of wastes produced over many years from the generation and sale of electricity to several different generations of customers. As far as I am aware, the Commission's only published decision involving similar facts occurred in connection with a request by Public Service Company of North Carolina (PSNC) to recover costs incurred to remediate environmental contamination at several decommissioned manufactured gas plants owned and formerly operated by it. See Order Granting Partial Rate Increase, Docket No. G-5, Sub 327 (October 7, 1994) (1994 PSNC Order). Even this precedent, at least so far as the published opinion discloses, did not address many of the most ardently contested issues in the current case. To mention only one prominent difference, there is no indication in the 1994 PSNC Order that the PSNC's history of management of the manufactured gas plants and associated environmental compliance involved any instances of criminal misconduct. In part because the facts of this case do not neatly conform to any prior precedent, I have chosen to write separately from the majority to set out my own views as to the appropriate disposition of the issues in this case.

In several important respects, I reach different conclusions from those of the majority, but in others, I am in accord with the Commission majority for the reasons stated in its opinion. Before turning to my areas of disagreement, I will briefly recap the matters where I concur:

First, I believe the majority correctly determines that the costs incurred to comply with the EPA's Coal Combustion Residuals Rule (CCR Rule) and with North Carolina's Coal Ash Management Act (CAMA) should be recovered on a system basis and not solely from North Carolina retail ratepayers.

Second, for the reasons stated in the majority's opinion, I agree that allowed costs should be allocated among retail customer classes based on an energy usage factor and not based on a demand factor, as requested by the Company and some of the intervenors.

Third, I concur in the majority's determination that the Company's proposal to recover as part of its fuel costs some $13.8 million for offsite disposal of ash wastes from its L.V. Sutton plant at Charah, Inc.'s Brickhaven facility in Chatham County may not be recovered under G.S. 62-133.2(a1)(9) for the simple reason that no "sale" of the waste by the Company occurred.

Finally, I agree with the majority's conclusion that it would be inappropriate to allow the Company to recover in its present rates those costs yet to be incurred for future disposal activities relating to the coal combustion residuals at the eight plants. Although

[1] Although I was not a member of the Commission and thus did not participate in the 2016 consideration of Dominion North Carolina Power's request, in Docket No. E-22, Sub 532, to recover similar waste disposal costs, for reasons set out in the majority opinion, I agree that the ruling in that case rests on materially different facts and considerations and, therefore, is not precedent for this case.

the Company has offered its best projection on its expected year-by-year expenditures going forward, the Company's witnesses conceded that there was some measure of uncertainty in those projections, if for no other reason than that the volume of combustion wastes in each of the nineteen impoundments is not yet known with certainty, and disposal costs will vary according to the quantities finally determined. Also, as I note later with respect to the Roxboro and Mayo plants, regulatory approval has not yet been secured for the Company's plans for some of the waste impoundments, and the outcome of those approvals may significantly alter the Company's present cost estimates.

A. Framing the Issues – Part One

Following the precedent of the 1994 PSNC Order, I believe the Commission should consider both whether the Company's expenditures to comply with current law were reasonable and prudent as to the elements and the amount of the expenditures, and also whether the Company's history of design, construction, operation, and maintenance of the waste impoundments were reasonable and prudent. The Company's position appears to be that the first of these inquiries is dispositive in itself. I do not agree. It is worth noting that the Commission observed, in the 1994 PSNC Order, that PSNC had handled the wastes and byproducts from the gas manufacturing process in accord with laws applicable at the time. See 1994 PSNC Order, at p. 20. That fact, however, did not lead the Commission to conclude that it was therefore unnecessary to undertake a review of the reasonableness of PSNC's operation of the plants before they were finally closed.

Left unresolved by the 1994 PSNC Order, at least so far as the order itself discloses, is the matter of reconciling the outcome of the two determinations if the results diverge. Consider that if the Commission were to conclude that both the fact and the amount of the current expenditures for ash disposal are reasonable and prudent and that the Company's historical handling of the coal combustion wastes also was reasonable and prudent, the need to resolve conflicting determinations does not arise. Likewise, if the Commission were to conclude that the historical operation of the waste impoundments was reasonable and prudent but that some or all of the proposed current expenditures for closure and permanent disposal of the combustion residuals were not reasonable and prudent, either in fact or in amount, then the Commission would disallow some items or amounts and allow others, but would not look further.

The more difficult case is the one which I believe arises on the evidentiary record as it stands. With limited exceptions as to specific items challenged by the Public Staff, none of the objecting intervenors has questioned the reasonableness of the items of expenditure or the amounts of those expenditures that the Company proposes to recover on account of its efforts to comply with current law relating to the disposal of coal ash wastes. However, using several different theories, emphasizing various different pieces of evidence, and proposing several different remedies, the Public Staff, the Attorney General's Office (AGO), and all of the objecting intervenors have challenged the reasonableness and prudence of the Company's historical management of coal combustion wastes. In so doing, they have presented the Commission with the task of deciding from the record how, to what extent, and in what amounts the Company's history of waste management affected or impacted, if at all, its current and expected future expenditures for permanent disposal of the coal combustion residuals. This is not a simple determination, and it will occupy much of my remaining discussion.

B. Framing the Issues – Part Two

A second challenge centers on proper characterization of the items of cost associated with disposal of ash wastes for purposes of applying G.S. 62-133. Here, the difficulty comes from the tendency of all parties to speak about the wastewater impoundments where most of the wastes are now stored as being in the nature of "property," or "plant," or "facilities" within the scope and meaning of G.S. 62-133(b)(1). While this manner of speaking and thinking is understandable, it is strictly correct only insofar as the impoundments are now or were formerly used and useful for the treatment of the wastewater used to flush coal combustion residuals from the generating facilities before recycling the water for other plant uses or discharging the treated wastewater to nearby surface waters.[1] However, it is not the impoundments themselves that are at issue in this proceeding; instead, it is the ash wastes that have accumulated in them. The costs the Company has incurred and will continue to incur arise not from the impoundments *per se*, but instead from the need to permanently dispose of the waste combustion residuals that have accumulated in them. In my view, costs to dispose of waste products generated from the burning of coal are very plainly operating expenses within the meaning of G.S. 62-133(b)(3). Those waste products are not in any sense "property," "plant" or "facilities" comprehended by G.S. 62-133(b)(1). Consider that disposal of these wastes can occur in several ways. They may be sold for beneficial reuse as structural fill, mine reclamation, additive for concrete, or for other uses. They may be removed for permanent disposal offsite in landfills owned by a third party. Certainly none of such disposal methods would involve the Company's "plant" or "facilities." Permanent disposal of the wastes on the Company's own property, in a landfill, or in a properly closed impoundment that was formerly used for wastewater treatment purposes are other methods of disposal of the wastes, but those methods of disposal do not convert the disposal costs from being treated as operating expenses to being treated instead as investment in "plant" or "facilities." I emphasize this point primarily because proper characterization of the costs at issue is, I believe, an important first step in determining how those costs should be allowed and recovered.

C. The State of the Record

On the questions thus framed, the state of the evidentiary record leaves something to be desired. The Company presented no witness with first-hand knowledge or experience regarding its waste ash management policies, decision-making, or operating practices prior to 2014. Company witness Kerin provided clear and comprehensive testimony concerning the Company's decision-making and activities with respect to coal combustion residuals after his assignment to the issue in 2014, but he came to his task with no prior experience relating to the issue. Company witness Wells gave informative and knowledgeable testimony concerning the Company's history of environmental compliance, but only for the period after 2009. Company witness Wright had no prior education, training, or experience with the management of coal combustion residuals, and his testimony largely consisted of opinions on matters of interpretation of law and legal inference, which are in any event the province of the Commission itself and not subjects for witness testimony.

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[1] Some of the impoundments also were used to treat wastewater streams originating from plant processes other than coal combustion.

From the Public Staff and intervenors, only AGO witness Wittliff had first-hand knowledge and experience of ash waste handling practices during the time period prior to 2000 and extending back to earlier decades. His experience, while certainly relevant and highly important in evaluating the Company's conduct, was based only on a review of Company records and documents produced in discovery and did not involve a first-hand inspection of any of the waste impoundments or contemporaneous knowledge of the Company's historical activities. Even so, I find witness Wittliff's overarching opinions and conclusions to be entitled to substantial weight, especially in the absence of contrary testimony from any other witnesses with more direct knowledge.

Much of my own evaluation and assessment, therefore, depends ondocumentary evidence which itself has many gaps, especially in regards to the operating history of the individual waste impoundments at the Company's eight plants. The state of the evidentiary record is, I believe, in large part a consequence of the framing of the issue by the Company, as explained above. If the reasonableness and prudence of the Company's proposed cost recovery is limited solely to examination of the items of expenditure and the amount of expenditures incurred by the Company to comply with CAMA and the CCR Rule from and after the date of enactment of those regulations, then it is not necessary to present extensive evidence concerning the decisions, policies, and operating practices that occurred over the many years prior to the adoption of the CCR Rule and the enactment of CAMA. As already noted, I think this framing of the issue is incorrect, but that conclusion then requires an answer as to what the Commission should do about the state of the record. There are, I think, several possible responses.

One is to accept the often-repeated conclusory testimony of the Company's witnesses, that during the decades prior to 2014, the Company's management of wastes from the burning of coal was reasonable and prudent and in accord with prevailing industry standards and practices. I find this testimony, especially coming from witnesses with no experience of the matter and which merely restates the ultimate issue to be decided, to be unacceptable. In large part, I am compelled to do so because the conclusory statements of the witnesses simply cannot be reconciled with the Company's admission in the federal criminal cases that it had been criminally negligent over a period of at least several years with respect to the matters charged, meaning that it failed to exercise the degree of care in the management of the waste impoundments that a reasonably prudent person would have exercised. As the Company's counsel explained in his address to the District Court: "I want to talk for a second about the kinds of crimes that the company has acknowledged and pleaded guilty to. These are crimes of negligence. These are negligence-based crimes." (Err. Ex. Vol. 15, p.61.)

A second approach would be to conclude that the Company has failed to carry its burden of proof as to the reasonableness and prudence of its historical coal waste management policies and practices. In its post-hearing briefing, the Company points out that under the prevailing procedural and evidentiary standards, the Company's expenditures should be presumed to be reasonable and prudent until an objecting party steps forward with evidence suggesting to the contrary, at which point the Company bears the burden of proof to substantiate the reasonableness of the expenditures. The Company argues that no party other than the Public Staff satisfied the initial prong of this procedure, and that the Public Staff did so only with respect to the discrete items of expenditure recommended for disallowance by witnesses Garrett and Moore and by witness Lucas. I believe that the precedents cited by the Company are inadequate to carry the weight of the burden such precedents place upon them. When the matter under review involves the reasonableness and prudence of a known and discrete expenditure made at a definite point in time, it is appropriate to require that parties challenging that expenditure come forward with some evidence that reasonable alternatives were available and to quantify the amount of the alleged error. See State ex rel. Utils. Comm'n v. Conservation Council of North Carolina, 320 S.E.2d 679, 312 N.C. 59 (1984). In this case, the challenges made by the Public Staff, the AGO, and the intervenors, except in the case of specific items of expenditure challenged by the Public Staff, do not involve discrete, known items of expense but are instead matters of omission, inaction, inattention, neglect and delay. From the very nature of the errors asserted by the objecting parties, it is not possible to reconstruct hypothetical histories and then, today, after many years, reconstruct the costs that might have been incurred under those alternative histories. I would find that there was ample evidence presented by several of the intervenors, by the AGO, and by the Public Staff, to put at issue the reasonableness and prudence of the Company's historical coal waste management policies and practices and thereby require the Company to carry its burden of proof on that subject.

The consequences of adopting the second approach and denying the Company all cost recovery for failure to carry its burden of proof would have severe financial consequences for the Company and would, as the majority points out, likely lead to the Company's having to pay even higher costs to secure equity and debt financing for future operations and investments, a result that would significantly harm ratepayers. It would, I believe, fail the fundamental test set out in G.S. 62-133(a), requiring that the Commission's determination of rates be fair and reasonable not only to objecting parties and ratepayers, but also to the Company.

Complete disallowance of all coal ash disposal cost recovery on the ground that the Company has failed to carry its burden of proof also flies in the face of common sense. Had the Company's management of coal combustion wastes resulted in no exceedances of the state's 2L groundwater standards, no violations of any NPDES permits, no criminal prosecutions, and no civil or administrative lawsuits, the record taken as a whole shows that the Company would eventually have been required to undertake many or even most of the ash disposal activities now required of it by the CCR Rule and CAMA. As evidence for this, I refer to the Company's 2004 study and report concerning options for long-term management of combustion residuals at its L.V. Sutton plant, which I consider to be one of the more important documents admitted into evidence in this case. (Ex. Vol. 22, pp. 165-211.) The 2004 study was authored *before* the Kingston, Tennessee, ash spill in 2008, *before* the promulgation of the initial drafts of the CCR Rule, *before* the administrative actions commenced by the North Carolina Department of Environmental Quality (DEQ) against the Company in 2013, *before* the 2014 spill at Duke Energy Carolinas, LLC's Dan River plant, *before* the adoption of the final CCR Rule, and *before* the adoption of CAMA. As the study discloses, even in 2004, when the regulatory regime was defined by the Clean Water Act and NPDES permits issued pursuant to that statute, by Part D of the Resource Conservation and Recovery Act, and by state regulations implementing those two statutes and imposing the 2L groundwater standards, the Company had developed the view that eventual closure of the existing impoundments would be required either by dewatering the impoundments and capping the ash in place, or by excavation of the ponds and disposal of the combustion wastes in dry landfills. As subsequent events proved out, the Company's assessment in 2004 turned out to be absolutely correct.

The third approach, and the only one I would find proper under the circumstances of this case, is to grapple with the available evidence, most of it documentary, in order to form a best judgment as to whether the Company's history of management of coal wastes is so flawed as to render its present expenditures for permanent disposal of those wastes unreasonable and, if so, how to quantify the effects of the past on the present. On the record as it stands, I believe the only way to undertake these two tasks is to consider the evidence on a plant-by-plant basis, and I attempt to do so in later sections of my opinion. First, though, a short discussion about the standard of care I believe should be applied in assessing the Company's actions and omissions.

D. The Standard for Evaluating the Company's History

Company witnesses and opposing Public Staff and intervenor witnesses alike concurred that regulatory standards and customary industry practices for handling and disposal of coal ash wastes have evolved over an extended period of years. (See, e.g., Ex. Vol. 16, p. 211; Tr. Vol. 16, pp. 109-135.) The question the Commission must consider is whether the Company acted reasonably in response to, and in light of, those evolving standards. This is made more difficult by the long period of development of scientific and environmental understanding and regulatory interest in coal combustion waste between the time of the Company's general rate case in 1987 and its next-but-this rate case in 2013. However, I believe that the record taken as a whole clearly reflects that, during that twenty-six year period, both "best practices" and regulatory requirements with respect to ash wastes advanced in a direction that converges toward the present mandates embodied in CAMA and the CCR Rule.

When environmental regulations prohibited discharge of fly ash from stacks, two methods of handling that ash developed. One, which had long been used with respect to bottom ash (including by the Company itself) was dry handling, which involved manual removal of the collected ash followed by dry disposal in either a lined or unlined landfill, land application, or dry stacking of the wastes. The second method involved using water to flush the accumulated ash, bottom ash and fly ash, and other combustion by-products, from the generating plant. The resulting ash laden wastewater was sluiced to detention ponds where the ash was allowed to precipitate and settle out, thereby permitting discharge or reuse of the treated wastewater. After enactment of the Clean Water Act in 1972, the regulatory regime applicable to wet handling of coal combustion residuals was primarily intended to address treatment of the wastewater before discharge and not the ultimate disposal of the waste ash itself. Hence the impoundments themselves should be considered – as they are and were treated under the Clean Water Act - as wastewater treatment facilities, not as permanent facilities for disposal of the waste combustion residuals.

The record establishes that the different environmental risks associated with wet handling of ash and the resulting accumulation of precipitated ash in the wastewater treatment basins, as compared with dry handling followed by permanent disposal of the ash in landfills, were well understood as far back as the time of the enactment of the Clean Water Act. When left in standing water, unprotected from rainfall or storm water runoff from surrounding areas, in impoundments that were not hydrostatically isolated from groundwater, there is now and was then a risk that constituents in the waste ash would migrate into groundwater or seep to the surface outside the impounded area. These are fact of elementary chemistry, hydraulics, and hydrology; they were not something awaiting discovery in some new scientific breakthrough.[1]

At all points after the time the emission of waste fly ash from smokestacks was prohibited, the Company had a choice between dry and wet methods of handling combustion wastes.[2] Although the applicable regulatory regime permitted the Company to choose between these two methods, that fact does not mean that their environmental and regulatory risk profiles were the same, nor does it absolve the Company from its obligation to implement its chosen method in a reasonable and prudent manner in light of the specific risks inherent in that method. The knowledge that is to be charged to the Company during the last four decades of the twentieth century, and the first two decades of this one, is not knowledge of what actions legislatures and regulators might take at some future point. Instead, the knowledge that the Company is charged with is knowledge of the different environmental consequences of dry management of ash in landfills or mineshafts versus wet management in wastewater treatment ponds, and these differences are matters of basic chemistry and hydrology. The Company's inability to predict regulatory and legislative developments does not mean it was unable to understand and foresee the environmental consequences of improper design, construction, operation, repair, and maintenance of the surface impoundments it chose to use for treatment wastewater laden with coal ash wastes.

The Company cannot disclaim contemporaneous knowledge of the basic differences between wet and dry handling of waste ash. As early as August, 1978, in connection with its review of the Company's proposal to construct an ash settling impoundment in the upper reaches of Crutchfield Branch at the Mayo plant, the North Carolina Department of Environmental Management advised that it was the State's intention to require that the Company "... provide controls as necessary for the prevention of pollutant materials from entering ground water and thereby reentering the surface waters some point downstream of the proposed dam," and further that the Company "...provide such testing as is necessary to assure that pollutants are not discharged to the ground waters and thereby to the downstream point of the Crutchfield Branch ..." (Ex. Vol. 22, pp. 216-217.) More generally, the Company's NPDES permits issued under the Clean Water Act contained certain standard conditions the Company was obligated to comply with, including the following:

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[1] In 1979, a researcher at the Los Alamos Scientific Laboratory submitted a report at the Environmental Technology Training Conference in Arizona, titled "The Disposal and Reclamation of Southwestern Coal and Uranium Wastes," which contained the summary conclusion that "[t]here is growing awareness that the discarded wastes from coal combustion are a serious potential source of surface and ground water contamination." (Ex. Vol. 22, p. 224.) The author of the report cited to a number of other contemporaneous papers and reports on the subject. Although no Company witness testified to personal knowledge of this report, it is indicative of the general state of knowledge at the time. The applicable standard is, in any event, not what the Company actually knew, but what it reasonably could and should have known. See 78 North Carolina Utilities Commission Orders and Decisions 238, pp. 251-252 (August 5, 1988).

[2] In its 1988 report to Congress on the question of whether coal combustion wastes should be regulated as a hazardous waste under Subpart C of the Resource Conservation and Recovery Act, the EPA notes that, by that date, the most common method of disposal of waste ash throughout the United States was in dry landfills. While surface impoundments were also very common, their use was concentrated in the southeastern United States where, the EPA noted that access to sufficient, affordable water can make surface impoundments a realistic, economic option. (Tr. Vol. 16, pp. 220-225; Ex. Vol.21, pp. 513-516.)

a. The Permittee shall take all reasonable steps to minimize orprevent any discharge or sludge use or disposal in violation of this permit with a reasonable likelihood of adversely affecting human health or the environment...

b. The Permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the Permittee to achieve compliance with the conditions of this permit...

(Ex. Vol. 17, p. 378; see also 40 C.F.R. § 122.41.) The Company, having chosen a method for waste handling that was known to have a potential risk of contamination of groundwater and surface water, I conclude that the degree of care expected of the Company in its management of the wastes should have been commensurate with that risk. Put differently, the standard of care expected of a reasonable and prudent utility is not now, and was not in the past, the absolute minimum necessary to avoid criminal prosecution or sanctions for violation of civil law; it was instead to take such actions as could or should reasonably have been taken at the time to minimize the risk that contaminants from coal ash waste would enter groundwater or surface waters.

Against the argument that the Commission's function is to be an "economic regulator," and not an "environmental regulator," I would respond that the position I have taken here is not tantamount to advocating that the Commission should substitute its judgment for that of DEQ or the federal EPA; it is just the very simple point that "reasonableness" for purposes of G.S. 62-133(b)(3) means something more than just not getting caught or, if caught, not getting prosecuted, fined, or sanctioned. Otherwise, there is really no way to carry out the General Assembly's declared policy that one purpose of the regulatory regime established in Chapter 62 is "...to encourage and promote harmony between public utilities, their users and the environment." G.S. 62-2(a)(5).

I would find from the record taken as a whole that the Company's history of managing wastes from burning coal to produce electricity contains significant and non-trivial evidence of inattention, inaction, and neglect in maintaining the wastewater treatment impoundments where the wastes were allowed to accumulate over a period of years, and that the Company was slow to take up and apply evolving best practices as they developed over time. From the very nature of unlined surface impoundments and the way water-borne contaminants enter groundwater and then migrate to surface water, any improper siting or construction of an impoundment or lax and inconsistent maintenance will have consequences that may become readily apparent only over an extended period of time. The parties focused their evidentiary presentations largely on events that occurred in the two most recent decades, most especially centering on the events that formed the predicate for the Company's federal criminal prosecution and the several civil administrative enforcement actions and private party lawsuits that were initiated during the same time period. The federal criminal charges against the Company use the formulation "... from at least [a recited date] ...," leaving open the precise date the charged misconduct may in fact have begun. I find it plausible to infer from the character of the alleged criminal violations and from the nature of the surface impoundments themselves, as noted, that the Company's actions, inaction, and omissions did not suddenly start at some date in 2010, 2011, or 2012, or another subsequent date certain, but were instead a continuation of prior operating practices.

As I have already observed, the Company's decisions to use unlined surface impoundments to manage waste combustion residuals were not *per se* unreasonable or imprudent at the time those decisions were made. To the question of whether the Company managed those impoundments with the degree of care, attention, and skill I think was required at the time, I would answer that the record contains sufficient evidence to conclude that it did not do so, even under the regulatory regime in place prior to the CCR Rule and CAMA, as evidenced by the fact that the federal criminal prosecution and the various civil administrative actions were all grounded on the regulatory regime predating the enactment of those two regulations. That is not, however, the end of the inquiry. As the majority notes, and I agree, the overriding difficulty confronting the Commission is how to quantify the extent to which the Company's past conduct translates into present costs incurred. As I have already pointed out, precision in doing this would require the impossible construction and evaluation of several different alternative histories and realities. Neither Public Staff witness Lucas nor the AGO witness Wittliff, the two principal witnesses whose testimony extensively and persuasively attacked and challenged the Company's claim that its historical management of coal ash wastes had been reasonable and prudent, was able to provide any general or overall quantification of the financial consequences of the Company's mismanagement.

III. COAL COMBUSTION WASTES – PLANT-BY-PLANT CONSIDERATION

I would conclude that the general evidence in the record concerning the Company's waste handling policies and practices is not adequate to support an across-the-board denial of all cost recovery, but neither is it sufficient to resolve all questions of reasonableness and prudence in the Company's favor. I do believe, however, that such general evidence is informative and instructive in deciding the weight that should be given to specific evidence going to the reasonableness of particular items of cost recovery in the Company's application. Although my general conclusions support and undergird the following discussion, I base my final determinations primarily on factors specific to the individual coal-fired generating plants in the Company's portfolio. As Company witness Kerin acknowledged in his testimony, every waste impoundment is different with respect to important matters such as topography, hydrology, engineering, surrounding environment, and operating history. (See, e.g., Ex. Vol. 17, pp. 127-129; Tr. Vol. 17, pp. 62-63.)

A. L.V. Sutton Plant

The evidence is most extensive for the two impoundments at the L.V. Sutton plant, one constructed in 1971 and the second constructed in 1984. In 2014, these two impoundments contained an estimated 3,540,000 tons and 2,780,000 tons, respectively, of combustion residuals. (Ex. Vol. 17, p. 79.) By January 1, 2017, this amount had been reduced to approximately 2,600,000 tons remaining in the 1971 impoundment and approximately 2,800,000 tons remaining in the 1984 impoundment. (Ex. Vol. 16, p. 210.)

In the present case, the Company seeks to recover $116,858,895 expended between January 1, 2015, and December 31, 2016, for disposal of the wastes at the L.V. Sutton plant.[1] The

[1] This amount, as with the amounts subsequently stated for the other plants, were provided by the Company on a system-wide basis and do not reflect the North Carolina retail allocation. They also do not include actual expenditures in 2017 through October 31, 2017

amount in contention among the parties is the disallowance of $80,513,871 recommended by Public Staff witnesses Garrett and Moore. **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]**

The Company contends that these expenses were necessary if the Company was to meet the CAMA-imposed deadline for permanent closure of the two impoundments. I would conclude that had the Company acted reasonably and prudently, it could have avoided the costs of offsite shipment and disposal to the Brickhaven site. Accordingly, I would deny cost recovery of the amount expended to prepare, transport, and then pay for permanent offsite disposal of any of the Sutton combustion residuals.

In reaching this conclusion, I rely in part on the testimony by Public Staff witnesses Garrett and Moore, who concluded that had the Company commenced construction of an onsite landfill on the same start date as it commenced transport of ash to the Brickhaven disposal site, it would have avoided the offsite disposal costs altogether. (Tr. Vol. 18, pp. 153-155.) The Company disputes witnesses Garrett and Moore's conclusion, noting that delays in receiving the necessary permit to construct an onsite landfill at the Sutton plant rendered it impossible for the Company to meet the CAMA-mandated deadline for closure of the impoundments and permanent disposal of the waste material in them. (Tr. Vol. 20, pp. 32-41, 56; Ex. Vol. 20, pp. 234-240.) The parties differ sharply on whether the Company can or should be able to avail itself of options provided in CAMA and in the federal criminal plea agreement to extend the compliance deadline to accommodate these delays. I find it unnecessary to resolve that disagreement for a more fundamental reason.

The evidence shows that by 2004, the Company recognized that the 1984 impoundment at the Sutton plant was nearing capacity and the end of its useful life, and that there were significant environmental concerns involving the 1971 impoundment. Accordingly, it undertook a study to identify options for a long-range strategy for combustion wastes at the Sutton plant. That study resulted in a report issued in November, 2004, containing a detailed analysis of both the then-current situation of the impoundments and disposal sites, in addition to alternatives for future management of ash. (Ex. Vol. 22, pp. 165-211.) According to the report, the objective was to identify a solution that would not only allow capacity for storage and treatment of coal combustion residuals from future electric generation *but would also utilize all of the ash previously deposited in the two existing impoundments.* (Id. at p. 168.) To repeat for emphasis, the study considered not only management of future combustion residuals, but also a long- term permanent solution for the waste ash in the existing impoundments.

This report considered both capacity constraints affecting the existing impoundments and known environmental concerns relating to the unlined 1983 impoundment.[1] Discussing these concerns, the report stated:

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[1] This impoundment is referred to in the report as the "1983 ash pond." In the Company's exhibits, this impoundment is not identified as such, but there is instead a reference to a 1971 impoundment. (Ex. Vol. 16, p. 210.) In the 2004 study, it appears that the reference to the unlined 1983 ash pond is meant to refer to the original 1971 impoundment and that the two are one and the same. (Ex. Vol. 22, p. 169.)

> The current environmental atmosphere is that these ponds will eventually have to be emptied and placed in a lined containment to eliminate the leaching of the ash products into the ground water system. This is an issue that is not currently being pressed, but it is anticipated that with the tighter environmental conditions it will soon become an emergent issue. This issue is aggravated by the fact that a test monitoring well located 300' from the edge of the 1983 ash pond has shown high levels of arsenic during the past two quarterly tests. This may or may not be related to the unlined ash pond.
>
> ....
>
> The plant lab personnel, plant management, the East Region engineers, and the environmental section are concerned with the ability to maintain the [NPDES] discharge permit limits of the ash pond associated with the continued running of the Sutton plant, as well as pond volume concerns.

(Id. at pp. 169-170.) According to the report, the Sutton plant needed an alternative solution for ash management in place by June, 2006. The target date was explained thus: "The 1984 ash pond is currently estimated to be non-operational due to Total Suspended Solids (TSS) limit exceedance which will cause a violation of the NPDES permit. The ash pond is expected to be un-operational by June, 2006." (Id. at p. 168.)

Unlike the majority, I find no ambiguity or uncertainty in the report about the need for immediate action, and that the identified need was not simply to add capacity for future waste handling. In the environmental analysis section of the report, the study team observed:

> The Analysis performed on each of the alternatives looked at both the current regulations and the current atmosphere related to regulatory regulations that are currently under review or have gotten an increased focus in the recent year. Unfortunately the past several years have seen an increased scrutiny in the ash storage regulatory area. While coal burning facilities are currently able to permit a new ash pond, every opportunity that regulators are allowed to look at existing sites and current practices it opens the facility up to questions and further scrutiny. This risk was taken into account in the ranking of the alternatives.

(Id. at pp. 179-180.)

The report identified ten alternative courses of action, including a "do-nothing" option. Three involved beneficial reuse, one involved an experimental new technology, one involved off-site landfill disposal in either a private landfill or a new landfill constructed by the Company, and the remaining alternatives involved some combination of dry stacking of the ash, construction of vertical dikes to increase capacity of the existing impoundments, or construction of a new, lined impoundment. (Id. at pp. 170-179.)

The recommended, preferred alternative identified in the study was one of the beneficial reuse options, noting that it would constitute "...a proactive approach that will positively impact the environmental position of the Sutton plant, and allow the company to benefit from the creation of a revenue generating project that will create a positive public image in dealing with an environmental issue associated with fossil plant electricity production." (Id. at p. 188.) While no witness was able to testify as to exactly what was done with the 2004 report and its recommendations, it appears from the record that none of the long-term solutions considered in the report had been implemented by 2014. (See Ex. Vol. 17, pp. 131-133 (closure plan for 1971 and 1984 impoundments)) I would conclude that had the Company taken timely action in 2004 when it had concluded that action was both necessary and appropriate, or even at any other time thereafter up until 2014, the delays and time constraints cited by the Company as its rationale for transport and off-site disposal of the waste from the Sutton impoundments could have been avoided. Accordingly, I would disallow as unreasonable and imprudent recovery of those costs identified by witnesses Garrett and Moore as the costs for transport and disposal of waste ash from the Sutton impoundments to the Brickhaven site.[1]

In addition to disallowance of the costs for transport and offsite disposal, I would also disallow the amount of $6,693,390 identified by Public Staff witness Lucas representing costs for extraction wells and treatment of groundwater relating to offsite contamination originating from the Sutton impoundments. (Tr. Vol. 18, p. 279.) As is recited in the Company's settlement agreement with DEQ, these costs are for accelerated groundwater remediation going beyond the requirements under CAMA for closure of the Sutton impoundments. (Ex. Vol. 21, pp. 586-598.) The 2004 report concerning a long- term management strategy for ash wastes at Sutton noted that by that date contaminants often found in coal ash had been identified in at least one groundwater well near the 1983 impoundment, but the report drew no conclusions about the source or extent of possible groundwater contamination. In discussing the "do nothing" option, the authors of the report noted:

> This alternative would not alleviate the potential emergent projects associated with the unlined 1983 ash pond or the pre-ash pond disposal site, and the monitoring well issues.

(Ex. Vol. 22, p. 184.) Instead of taking timely action when it knew that action was required, the Company waited another decade, until action was forced by DEQ's issuance of a Notice of Violation based on exceedance of the state's 2L groundwater standards. By that time, evidence of groundwater contamination existed not only on the plant site itself but at the property boundary and offsite beyond. I would find that the Company's failure to act in response to the recommendations of the 2004 report unreasonably and imprudently increased the risk of additional groundwater contamination and of migration of contaminants to and beyond the property boundary, and that its inaction is directly linked to the groundwater remediation costs incurred as part of its settlement of the 2014 Notice of Violation issued by DEQ.

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[1] I do not agree with witness Garrett and Moore's recommended disallowance of **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]** for installation of liner material that they contend was in excess of applicable regulatory requirements. (Tr. Vol. 18, p. 154.) In light of the history of offsite groundwater and surface water contamination associated with the Sutton plant, I would not penalize the Company for taking additional steps to help ensure that contaminants from landfilled wastes did not leach to groundwater after permanent disposal of the waste material.

B. Asheville Plant

The two impoundments at the Asheville plant, known as the 1964 ash pond and the 1982 ash pond, contained as of August, 2014, an estimated 2,200,000 tons and 800,000 tons of coal ash, respectively. (Ex. Vol. 17, p. 79.) By January 1, 2017, the Company estimated that the 1982 impoundment contained no remaining combustion residuals, and the 1964 impoundment contained 2,900,000 tons of ash, the difference in these figures largely resulting from the Company's temporary transfer of ash from the 1982 impoundment to the 1964 impoundment in order to facilitate construction of its new combined cycle gas generating plant within the footprint of the 1982 impoundment. (Ex. Vol. 16, pp. 209-214.)

Controversy centering on the management of combustion residuals at the Asheville plant centered on three topics: the Company's guilty plea to one count in the criminal indictment relating to unpermitted discharges from engineered seeps at the Asheville plant, the Company's decision to transfer ash from the 1982 impoundment to the 1964 impoundment prior to shipment to an offsite landfill for permanent disposal, and the Company's decision to dispose of the ash at a more distant and more expensive landfill facility in Georgia instead of using the landfill facility located at its affiliate's Cliffside plant in North Carolina.

The action that formed the basis for the Company's plea to one count of violating its NPDES permit for the Asheville plant is summarized in the following statement of counsel at the hearing before Judge Howard:

> ...[I]t's fair to say there is a disagreement among us about whether a seep by itself that simply percolates up and may reach a water of the United States is a violation of the law. The Government takes the position it is. That issue is not resolved in this plea. What the company did in this plea is it acknowledged it should not have had specific engineering structures that take seeps, pull them together and then put them into a water of the United States, unless it was part of the permit.

(Ex. Vol. 14, p. 382.) Translating "specific engineering structures" into simpler English – the unpermitted discharge was an intentional action, not simply the result of inattention or neglect. Although I would find that this admission by the Company is some evidence supporting the imposition of a penalty for mismanagement, I would not find that it affected the reasonableness of the costs the Company has actually incurred in order to permanently dispose of the waste in the two Asheville impoundments.

Several parties argued that "but for" the Company's criminal prosecution, which was based in part on the unpermitted discharges from the Asheville impoundments, the Company might have been able to dewater, cap the waste ash, and thereby close the impoundments in place, avoiding the higher costs of CAMA's mandate that the impoundments be excavated and the ash removed to a dry landfill. Drawing conclusions about "might-have-beens" is inherently difficult and is especially so when the "might-have-been" relates to legislative actions. With respect to the two Asheville impoundments, that task is rendered even more complicated because of the enactment of S.L. 2015-110 (Mountain Energy Act of 2015), which required the accelerated closure and decommissioning of the remaining coal-burning generation units at the Asheville plant. To replace those coal-burning units, the Company's only reasonable option was to excavate the

1982 impoundment and construct a new gas-fired combined cycle plant within the footprint of the impoundment. Excavation, in other words, was independently driven, at least in part, by the need to comply with the Mountain Energy Act of2015.

On the two remaining matters in dispute relating to closure of the Asheville impoundments, I am persuaded by the Company's testimony that the timelines necessary to comply with the Mountain Energy Act of 2015 could not have been reasonably anticipated by the Company, and that such compliance required immediate removal of ash waste from the 1982 impoundment in order to enable construction of the new generating plant. The Company has acknowledged, however, that the contract prices it paid in 2015 and 2016 for transport and offsite disposal of the wastes from Asheville may have been excessive in light of later prices it was able to negotiate, and that an adjustment in the costs of offsite disposal of $9,500,000 would not be inappropriate accordingly. (Tr. Vol. 20, p. 45.) Accordingly, like the majority, I would reduce by $9,500,000 the costs of offsite disposal for which the Company seeks recovery.

C. Roxboro and Mayo Plants

The Company's Roxboro coal plant has two ash impoundments, known as the East Basin, constructed in 1966, and the West Basin, constructed in 1973. As of January 1, 2017, the total combined estimated amount of combustion residuals in these two basins was approximately 19.7 million tons. (Ex. Vol. 16, p. 209.) The Mayo plant has a single impoundment, constructed in 1983, which holds an estimated 6.6 million tons of combustion residuals. (Id.) These two plants are still in operation and the three impoundments are still receiving ash and combustion residuals from the burning of coal to generate electricity for current customers.

To date, the Company has expended a total of $14,867,363 to prepare and submit to DEQ a plan for closure of the Mayo impoundment, including preparation of engineering plans and cost estimates. (Ex. Vol. 16, p. 268.) For the Roxboro plant, the Company has expended and seeks recovery of $20,370,325 for the same activities. The closure plans for all three impoundments call for leaving the combustion residuals in place, installing a cap over the waste material, and taking other steps to guard against migration of ash from the capped impoundments. The Company is not now seeking recovery of any costs for implementation of its proposed closure plans.

In this case, Sierra Club witness Quarles testified, based on his expertise and prior experience with coal waste issues[1] and his analysis of the site conditions, topography, hydrology, and operation of the two impoundments at the Roxboro plant and the one unit at the Mayo plant, that the closure plans proposed by the Company for those units would not meet the requirements of the CCR Rule or of CAMA, and would not protect against future migration of contaminants from the ash into groundwater and, ultimately, surrounding surface waters. (Tr. Vol. 13, pp. 132-73, 175-77.) Witness Quarles' opinion, which was left essentially unrebutted by any Company witness, places in doubt the appropriate treatment of the preparatory and planning expenditures incurred by the Company for which it seeks recovery in this case.

[1] Witness Quarles' testimony is entitled to substantial weight. He was involved in the development of a monitoring program to determine the lateral extent of contamination from the 2008 Kingston, Tennessee ash spill and thereafter has been involved with investigations at more than 70 coal ash disposal sites in the United States. (Tr. Vol. 13, p. 131.)

One option would be to allow the Company's current request for cost recovery subject to later adjustment or offset against actual final closure costs as determined in a future general rate case. This option is unsatisfactory since it would involve improper retroactive ratemaking – costs approved for recovery in this case might be disallowed and ordered disgorged in a later case. A second option would be to accept witness Quarles' opinion, which is that the Company is proposing an unworkable and, therefore, unreasonable and imprudent closure plan, and, as a result, disallow the costs in their entirety in this case. I likewise find this option unacceptable since it would preempt a decision that is properly to be made by DEQ and not by the Commission. The sufficiency of the Company's closure plans for these three impoundments is a matter that should first be decided by DEQ, after which the Commission can review the record and make a determination of the reasonableness and prudence of the costs the Company has incurred and will incur. I would therefore conclude that the most appropriate treatment of the costs incurred to date with respect to the three impoundments at the Roxboro and Mayo plants would be to allow the Company to defer those costs to a regulatory asset account for possible later recovery in a future general rate case, after closure plans have been approved by DEQ, and upon presentation of a more fully developed record concerning the history of ash management policies and practices at the two plants.

D. H.F. Lee Plant

The Company's H.F. Lee plant in Wayne County was decommissioned in 2012. At that time, there was one active wastewater impoundment at the plant site – theso-called 1982 basin, which was constructed in 1978, containing as of January 1, 2017, an estimated 4.5 million tons of combustion residuals. (Ex. Vol. 16, p. 210.) In addition, there were four inactive or abandoned impoundments as follows: (a) the 1950 basin, last used in 1963; (b) the 1955 basin, last used in 1969; (c) the 1962 basin, last used in 1973; and (d) the so-called "polishing pond," which opened in 1982 and was last used in 2012.[1] Collectively, these four impoundments contained an estimated 1.709 million tons of combustion residuals as of January 1, 2017. (Id.) In this case, the Company seeks to recover $20,759,183 in expenditures made in 2015 and 2016 for preparation of closure plans, engineering for implementation of the plans, and for expenses relating to dewatering the ash in the active impoundment. As far as the record discloses, these costs are not further broken down between the four inactive impoundments and the remaining active 1982 basin.

The inactive impoundments at the Lee plant are, together with those of similar vintage at the Cape Fear plant, the oldest among the Company's total of nineteen impoundments. Three of the four were constructed before the Clean Water Act became effective, and active use of the impoundments ceased before the practice of lined impoundments became widespread. None of the four are subject to the CCR Rule, although their closure is mandated by CAMA. (Id.) The 1950, 1955, and 1962 impoundments were inactive and were no longer in use by the time of the Company's 1987 general rate case. (For shorter reference, I will call these the "pre-1973 impoundments," since they were all inactive by 1973.) The record does not disclose whether any allowance for costs of closure of the pre-1973 impoundments and permanent disposal of the waste ash was made in that rate case.

[1] The exact status and history of the "polishing pond" is not detailed in the record. It is estimated to contain only approximately 9,000 tons of wastes and, therefore, does not appear to materially affect the Company's total expenditures.

No party has contested that the items of expenditure or the amounts of the expenditures made by the Company with respect to the impoundments at the Lee plant are reasonable and prudent. The difficulty I find with the Company's request for cost recovery centers on the inactive impoundments, and more particularly on the fact that the pre-1973 impoundments were last used for wastewater treatment and removal of combustion residuals between thirty and thirty-five years before the enactment of CAMA. The impoundments themselves, whose purpose was to treat ash laden wastewater before the treated wastewater could then be discharged into surface waters or recycled for other purposes at the plant, have served no such purpose for the same period of time. The waste products that now must be removed from the footprint of the impoundments and permanently disposed are the residuals from coal burned to generate electricity for a very different group of customers than the Company's current ratepayers.

Based on these factors, I find the principle supporting the Court's decision in State ex rel. Utils. Comm'n v. Edmisten, 291 N.C. 451, 232 S.E.2d 184 (1977), to be an apt one for this case – that the costs of service should be borne by those who were customers during the period the service was rendered. Id., 291 N.C. at 470-71, 232 S.E.2d at 195. The facts in Edmisten differ from those in this case in several respects, and Edmisten presents a simpler illustration of the general principle stated. The question that I believe implicates Edmisten in this case can be formulated in the following way. Permanent disposal of waste products from the generation of electricity is an expense directly associated with the generation of that electricity and should, therefore, be treated as an ordinary expense of operation. However, perfect identity between the time period during which electricity is generated and the time the resulting waste products are permanently disposed is not reasonable or even possible. The water used to flush the waste products from the plant must first be treated to remove the combustion wastes, and some accumulation or storage of that waste must occur in order to permit the most efficient and cost-effective permanent disposal of the waste. While an impoundment is still receiving new wastes and is used for treatment of wastewater, removal of accumulated wastes in the impoundment may be impractical and costly. Because some delay between the generation of coal combustion wastes and their final, permanent disposal is not unreasonable, the question then is when does the delay between (a) the production of waste in the course of generating electricity to serve one group of customers and (b) the final disposal of that waste accompanied by a request that then-current customers shoulder the costs of disposal become so great that it offends the principle articulated in Edmisten?

In the case of impoundments that were still actively receiving combustion residuals and treating wastewater when the Lee plant and several others were retired in 2012, it is reasonable for present ratepayers to be assigned costs associated with the final, permanent disposal of the wastes remaining in those impoundments at the time of their decommissioning. However, I would find that this is not so in the case of the pre-1973 impoundments. This distinction in treatment is supported, I believe, by the essentially undisputed evidence in the record as to the manner in which the pre-1973 impoundments were "decommissioned" at the time.

Company witness Kerin testified that when use of the inactive impoundments ceased, no steps were taken to dewater the ash remaining in the impoundments, although over time the impoundments dewatered naturally. (Tr. Vol. 17, pp.116-117.) He also testified that "...at a retired site, the first thing you want to do is start removing the water. That improves the factors of safety of the dam. It also, if you would have seep issues, that will eliminate the seeps." (Tr. Vol. 16, pp. 173-174.) Nor was anything done to protect the ash from rainwater or from storm water runoff from surrounding areas, such as by capping the accumulated ash in place or engineering storm water diversions. None of the ash was excavated and placed in dry stacks, piles, or landfills, and no groundwater monitoring or leachate collection system was installed to detect and prevent migration of contaminants from the ash into groundwater and nearby surface water. (Tr. Vol. 17, pp. 117-118.) Witness Kerin testified that from the time use of the impoundments ceased, no actions were taken other than performing inspections of the dams. (Id. at pp. 118-119.) [1]

In his direct testimony, witness Kerin attempted to avoid the matter of the inactive impoundments by testifying as follows: "In the absence of any regulatory directive to do so, the Company reasonably did not pursue and should not have pursued regulatory closure or retrofitting *for any site that was still generating ash* and that maintained its NPDES permit." (Tr. Vol. 16, p. 115 (emphasis added)) In other words, final disposition of the waste ash accumulated in any impoundment, even an inactive one, could await decommissioning of the generating plant itself. I find this position wholly unpersuasive. It is equivalent to claiming that it would be reasonable and prudent to leave hazardous sludges left from equipment cleaning solvents to be stored in leaking metal containers on an open and unprotected part of the power plant site for as many decades as the plant thereafter continued in operation, without any regard to what might become of them in the meantime.

In short, the pre-1973 impoundments at the H.F. Lee plant were not so much "closed" as they were abandoned, along with the combustion residuals left in them.[2] I would conclude that the Company's failure to take any steps to ensure that the ash in the pre-1973 impoundments remained in place and that contaminants did not enter groundwater or surface water at any time until it was forced to take action by the enactment of CAMA in 2014 was unreasonable and imprudent, and that the extended delay in taking any action to dispose of the ash on a permanent basis violates the principle of Edmisten.[3]

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[1] Interestingly, when the Lee plant was retired in 2012, the Company commissioned a study of the activities required for decommissioning and the costs associated therewith. This study pre-dated adoption of the CCR Rule and the enactment of CAMA, but was intended to be responsive to the regulatory regime in place at the time under the Clean Water Act and applicable state groundwater protection regulations. For the impoundments at the Lee plant, the study indicated the "[e]xisting ash ponds will be pumped dry, filled with inert debris, capped with 40 mil geo-membrane, geo-net drainage, 18 inches of soil, and vegetated cover." (Ex. Vol. 20, p. 180.) The same activity was indicated for the impoundments at the Cape Fear, Weatherspoon, and L.V. Sutton plants. While there is no evidence to indicate whether CAMA would have addressed the inactive impoundments at the Lee plant differently had they been sooner closed in the manner recommended in the 2012 study, it is reasonable to ask whether the result under CAMA might have been different had the Company taken action to permanently close the impoundments and secure the ash in them within a reasonably prompt period of time after use of the impoundments was discontinued.

[2] The 1988 EPA Report to Congress indicates that as of 1983, North Carolina had in place regulations governing closure of surface impoundments. (p. 4-4) The record in this case does not further detail what those regulations provided. The EPA report does illustrate, generically, two methods of surface impoundment closure – removal of the wastes and dewatering the wastes and covering them with a soil cover. (Tr. Vol. 16, pp. 220-225; Ex. Vol. 21, pp. 513-516.) Whatever the state of the regulations at the time, the undisputed evidence from the Company's own witness is that nothing at all was done when use of the pre-1973 impoundments ceased.

[3] I do not believe this result is inconsistent with the Commission's 1994 PSNC Order due to significant factual differences between the cases. The manufactured gas plants owned by PSNC were acquired from other owners who had operated them for many years before PSNC purchased them. Three of the six plants were jointly owned with

The Company has provided no allocation between the pre-1973 impoundments and one active impoundment of any of the costs for which it seeks recovery at the Lee plant; however, witness Kerin testified that although disposal costs of ash wastes are not a direct function of quantities, quantity is certainly a very important determinant of cost. (Tr. Vol. 17, p. 54.) Some costs, such as preparation and submission of a plan for permanent disposal, site mobilization, and similar items, could be considered common to all the different impoundments at a single site, and it seems reasonable to allocate those common costs based on the most important variable involved – the quantity of the wastes in each impoundment. Accordingly, relying on the data provided by the Company in Kerin Direct Exhibit 5 and using the allocation method just described, I would disallow 37.9% of the total for which the Company seeks recovery in this case on account of the impoundments at the H.F. Lee Plant.[1]

E. Cape Fear Plant

The Company's Cape Fear plant near Moncure was decommissioned in 2012, at the same time the H.F. Lee, Weatherspoon, and the coal units at the L.V. Sutton plants also were retired. At that time there was one impoundment constructed in 1985 that was still receiving some waste. The Company estimated that the volume in this 1985 impoundment as of January 1, 2017, was approximately 2.8 million tons. Also at the plant site were four other impoundments whose use had ceased by not later than 1985, as follows: (a) the 1956 impoundment, whose use ceased in 1963; (b) the 1963 impoundment, no longer used after 1978; (c) the 1970 impoundment, discontinued in 1978; and (d) the 1978 impoundment, which no longer received waste after 1985. Taken together, these four discontinued impoundments contained an estimated 2.9 million tons of combustion residuals as of January 1, 2017. None of these impoundments are subject to the CCR Rule, and the Company's expenditures are mandated solely by the requirements of CAMA.

In this proceeding, the Company seeks to recover a total of $16,052,310 in expenditures to cover preparation of closure plans, engineering for implementation, and mobilization and dewatering of the 1985 impoundment. As is the case for the pre-1973 impoundments at the H.V. Lee plant, the four Cape Fear impoundments whose use ceased in or before 1985 (hereafter referred to as "the pre-1985 impoundments") are not subject to the CCR Rule, but are instead subject to

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other parties. As far as the 1994 PSNC Order discloses, there was no evidence or finding that when the plants were finally closed in the 1950s, PSNC in any way failed to take steps that were reasonably and prudently known and possible at the time, based on the state of PSNC's knowledge and understanding at that time. I also find it significant that, whereas the Commission found that PSNC had handled by-products from the manufacturing process consistent with applicable laws at the time, in this case the Company's federal criminal admissions, the DEQ administrative and civil actions, and private party civil litigation all relate to actions or omissions under the Clean Water Act, which was in effect at the time two out of the five Lee impoundments were last in use. (Ex. Vol. 16, p. 210.)

[1] Kerin Direct Exhibit 5 reports estimated tonnages of ash as of January 1, 2017, and might be thought more appropriate to base an allocation on the tonnages shown on Public Staff Kerin Cross Exhibit 3, which contains estimates as of August, 2014, when activities commenced to close the impoundments and permanently dispose of the ash wastes. However, the August, 2014 tonnages shown on Public Staff Kerin Cross Exhibit 3 for the closed impoundments are significantly *less* than the estimated tonnages as of January 1, 2017, notwithstanding the fact that the four inactive impoundments had not been receiving any new combustion residuals after August, 2014. (The totals for the one "active" impoundment are the same on both exhibits.) As indicated in the footnotes to the two exhibits, estimated quantities were subject to change based on detailed site examination and analysis. For that reason, I have concluded that Kerin Direct Exhibit 5 provides a more accurate basis for the proposed allocation. (Ex. Vol. 16, p. 210.)

closure as mandated by CAMA. The 1985 impoundment, though no longer receiving new wastes after 2012, is classified as "active" under the CCR Rule since it continued to impound water at the time the CCR Rule became effective. Again, as in the case of the impoundments at the H.V. Lee facility, the Company has provided no breakdown of its cost recovery request as between the 1985 impoundment and the pre-1985 impoundments.

The 1978 impoundment was the subject of Count 5 of the federal criminal prosecution, centering on the Company's failure to take timely and reasonable action to maintain and repair the riser and skimmer, allowing leakage in violation of the Company's NPDES permit. The facts are extensively reviewed in the Joint Factual Statement. (Ex. Vol. 21, pp. 142-150.) They demonstrate that the Company was slow to respond or non-responsive entirely to repeated evidence of problems with the riser and skimmer and knowledge that these problems were resulting in leakage from the impoundment. Not until 2013 did the Company begin to dewater the 1978 and 1985 impoundments. This was approximately 28 years after the 1978 impoundment had been retired, a delay that should be considered in light of witness Kerin's testimony, already noted, that the first thing that should be done when an impoundment is retired is to dewater the basin, thereby reducing the hydrostatic pressure that can cause or increase the likelihood of groundwater intrusion or surface seeps.

For the reasons discussed earlier concerning the pre-1973 impoundments at the H.F. Lee plant, I would disallow any cost recovery for removal and final disposal of the coal combustion residuals in the four pre-1985 impoundments at the Cape Fear plant. As was the case with the cost figures for the Lee impoundments, the Company did not provide a breakdown of its total request for cost recovery by individual impoundment. Using the same source of data and the same method of allocating the total costs as in the case of the H.F. Lee plant, I would disallow 50.87% of the total amount of cost for which the Company seeks recovery in this case in account of the impoundments at the Cape Fear Plant.[1]

F. Robinson Plant

The Company's Robinson plant in South Carolina has one impoundment constructed in the mid-1970s. (Ex. Vol. 16, p. 210.) The Robinson plant is now retired and the record is unclear as to the quantity of ash remaining at the plant site. Kerin Direct Exhibit 5 shows an estimate as of January 1, 2017, of approximately 3.2 million tons, while Public Staff Kerin Cross Exhibit 3 indicates that as of September 30, 2014, the quantity of ash in the impoundment was only 660,000 tons, with perhaps additional ash in dry stacks, piles, or otherwise present in some form at the site. This uncertainty is consistent with the general absence of evidence in the record concerning the Robinson plant's history of operations or the management of combustion residuals at the plant site. According to Kerin Direct Exhibit 10, the Company is in this case seeking recovery of $6,415,618 expended to date in preparatory engineering and related expenses for a closure plan to involve excavation of the ash at the site and permanent disposal in a lined landfill. (Ex. Vol. 16, p. 268.) The Company's closure plan has been approved by the South Carolina

[1] The discrepancies in tonnages between Kerin Direct Ex. 5 and Public Staff Kerin Cross Exhibit 3 that exist in the case of the H.F. Lee plant do not exist in the case of the Cape Fear plant. The small difference in totals likely reflects rounding or different methods of estimation.

Department of Health and Environmental Control, a fact which distinguishes the Company's expenses at the Robinson site from the situation with respect to the Mayo and Roxboro plants discussed earlier.

Because none of the intervenors presented evidence disputing the reasonableness or prudence of the Company's expenditures for which it seeks recovery, or concerning the Company's history of management of combustion residuals at the Robinson plant, I would conclude that they should be allowed for recovery in this case, subject to amortization along with other allowed costs for ash remediation and disposal.

G. Weatherspoon Plant

As in the case of the Robinson plant, the parties' evidentiary presentations gave small attention to the Company's Weatherspoon plant, which was retired in 2011 and, at the time of its decommissioning, had one active ash impoundment constructed in 1955 and containing, as of January 1, 2017, combustion residuals estimated at either 2.5 million tons (Ex. Vol. 16, p. 210.), or 1,700,000 tons as of August, 2014. (Ex. Vol. 17, p. 79.) In this case, the Company seeks recovery of $9,120,342 incurred in connection with preliminary preparation of a closure plan and engineering for implementation of the plan involving excavation and offsite disposal of the ash remaining in the decommissioned impoundment. The Company has selected beneficial reuse as its preferred method for permanent disposal of the waste ash from the Weatherspoon impoundment.

The objecting parties presented little or no evidence concerning the reasonableness or prudence of the Company's expenditures for which it seeks recovery in this case, or concerning the Company's history of management of combustion residuals at the Weatherspoon plant. The Weatherspoon plant did not figure in the Company's federal criminal prosecution. Although the 2013 enforcement action commenced in Wake County Superior Court by DEQ contain allegations that the applicable 2L standards for certain groundwater contaminants (iron, thallium, and manganese) were exceeded in or around the Weatherspoon plant at various monitoring sites on various dates, the allegations of DEQ's Complaint are tentative and, in some cases, state that it is uncertain whether these exceedances are naturally occurring or whether corrective action will be required. (Ex. Vol. 22, p. 267.) DEQ's action was resolved by an order on motion for summary judgment, consented to by the Company. (Ex. Vol. 22, pp. 328-407.) Accordingly, I would find that there is insufficient evidence to disallow the costs forwhich recovery is sought in this case as imprudently incurred and that cost recovery should be allowed.

IV. COAL COMBUSTION WASTE – GENERAL MATTERS, ONCE AGAIN

This proceeding may be the first, but it will not be the last in which recovery of costs for permanent disposal of coal combustion wastes will be at issue. Two questions of moment for future rate cases were litigated in the present case. On one of those questions I am in substantial agreement with the Commission's majority but not so with the other question. Finally, I wish to set out my views about the mismanagement penalty ordered by the Commission majority.

A. Insurance Recoveries

The first matter relates to potential insurance recoveries that may be used to offset some portion of the costs the Company has incurred and will incur for permanent disposal of the waste materials. I concur in the majority's treatment of this issue and wish to set forth my own view as to why that treatment is appropriate. As the evidence disclosed, the Company's entitlement to recover under its insurance policies is currently in litigation that will not be finally resolved for a number of months or even some years. Accordingly, the Company is not presently able to make any useful prediction or estimation of its likely recoveries under the policies in litigation. The Company has proffered that any and all proceeds from the insurance litigation, by judgment or settlement, will be applied, net of costs of litigation, against its costs incurred to comply with CAMA and the CCR Rule. Of course, it is the Company's position that all of those costs are recoverable from ratepayers, now and in the future, including an allowed rate of return. I find this proposal highly unsatisfactory. Under it, the Company would retain full control over the litigation, including the pace of the suit, the costs of the suit, the development of evidence through discovery, the presentation of the case, and the determination whether to settle and, if so, for what amounts. Yet because the Company seeks full recovery from ratepayers today for all of the costs to which insurance coverage is potentially available, it lacks any real incentive to prosecute the pending insurance litigation vigorously, to settle the case for the highest amount that can reasonably be negotiated, or to control the costs of the suit. The Company would retain control but would have no stake in the outcome.

It is, I believe, premature to decide in this case how any insurance recoveries should be allocated between the Company's ratepayers and its shareholders and, in stating this view, I am in accord with the majority. Much depends on how the insurance litigation develops, most particularly on which issues will turn out to be central to the disposition of the litigation and what evidence is developed on those controlling issues. For now, however, I believe that the cost recovery disallowances and cost deferrals that I have advocated in this opinion would give the Company sufficient incentives to ensure that the insurance litigation is prosecuted vigorously and cost effectively. If the Company is able to prevail, either in whole or in part, the Commission will then have an opportunity to assess whether and in what amount the Company should be able to offset the insurance proceeds against items of cost that have been disallowed in rates or deferred for recovery.

B. Ongoing Coal Ash Disposal Costs

The second matter centers on the treatment of the Company's ongoing and future expenditures relating to waste ash disposal. As noted in the beginning, I concur with the majority that these costs are appropriately treated by allowing the Company to establish a regulatory asset account, with the amount of any eventual allowance or disallowance to be determined in one or more future rate cases. I depart from the majority, however, on the extent to which the Company may be allowed to accrue a rate of return on this regulatory asset account.

The expenditures that will be recorded to this account are, in my view and as I have already explained, operating expenses upon which a return is not ordinarily allowed. The Company contends that a rate of return is appropriate nonetheless since the expenses are being capitalized and will be funded from the Company's working capital, citing the decision in State ex rel. Utils. Comm'n v. Virginia Electric & Power Co., 285 N.C. 398, 206 S.E.2d 283 (1974) (VEPCO) for support of its position. The matter is not quite so simple. The Court in VEPCO did not hold that *all* amounts classified as working capital could be included in the utility's rate base upon which it was entitled to earn a return, but only those funds used as working capital that were provided by or belonged to investors. After first endorsing inclusion in rate base of the Company's own funds used as working capital, the Court pointed out:

> Conversely, the utility is not entitled to include in its rate base funds which it has not provided but which it has been permitted to collect from its customers for the purpose of paying expenses at some future time and which it actually uses as working capital in the meantime. Such funds, so supplied by the customers, are 'used and useful in rendering the service' and the utility, having lawfully collected them, is the owner thereof. Nevertheless, such funds, so collected from the customers and used by the utility as working capital, are not 'the public utility's property' within the meaning of G.S. 133(b)(1).

VEPCO, 285 N.C. at 415, 206 S.E.2d at 293. Importantly, the Court also observed that the determination as to when working capital is sufficient such that no additional amount is required to be included in rates is largely a subjective one. Id.

The record in the present case is unclear as to the extent to which the Company will require an increase in investor-provided working capital beyond what is currently available to fund ongoing expenditures for coal ash disposal. The Company has been able to fund from the revenues provided by existing rates and from existing working capital its coal ash expenditures in 2015 and 2016, and these amounts will be replenished as allowed by the Commission's order allowing amortization and recovery in rates of these expenditures. Although the Company contends that in some future years its expenditures for coal ash disposal will exceed its expenditures in the test year, it also acknowledges that in other years its expenditures are projected to be less. (Tr. Vol. 6, pp. 144-145.) In its application, the Company proposed to increase its pro forma cash working capital by $129.1 million on account of future expenditures for coal ash disposal costs, and to recover this amount from customers in rates. (Tr. Vol. 6, pp. 41-42.) This amount represented the Company's expenditures in the test year, which, as I noted already, it has funded from its existing working capital under current rates. I would infer from this requested number that the Company does not believe that it needs an increase in working capital for those years in which its future expenditures are projected to exceed the test year amount.

Because I am unable to determine from the record as it stands what portion, if any, of the Company's future coal ash disposal expenditures may require an increase in investor-provided working capital, I am therefore unable to support the accrual of a rate of return on amounts recorded to the regulatory asset account for future coal ash disposal costs.

C. The Penalty for Mismanagement

Finally, I write to explain my reasons for not joining the majority's decision to impose what it has called a penalty for mismanagement. The majority would allow all costs sought for recovery by the Company for the period January 1, 2015, through August 31, 2017, excepting only the $9.5 million excess disposal costs at the Asheville Plant. Its proposed penalty consists of amortizing recovery of the allowed costs over a five year period and including a return on the unamortized balance equal to the authorized combined return on rate base but then reduced by the sum of $6 million per year. The majority estimates that the value of this penalty is approximately $30 million. I cannot concur that what the majority has ordered constitutes, in any real sense, a penalty.

Requiring amortization over a period of years for extraordinary operating expenses is not unusual, and the five year period allowed by the majority for recovery of costs already incurred is what the Company has requested. I do not consider allowing a return on the unamortized balance, albeit at a reduced rate, to be a penalty in any meaningful sense. In Thornburg I, the Supreme Court upheld the Commission's allowance and amortization of certain costs associated with a cancelled generating plant as "reasonable operating expenses," while denying any return on the unamortized balance of such expenses. In the course of its discussion of the issue, the Court observed:

> While this statute [referring to G.S. 62-133(b)] makes clear that the rates to be charged by the public utility allow a return on the cost of the utility's property which is used and useful within the meaning of N.C. Gen. Stat. § 62-133(b)(1), the statute permits recovery but no return on the reasonable operating expenses ascertained pursuant to subdivision (3).

Id., 325 N.C. at 475, 385 S.E.2d at 458. Elaborating on this point later in the same opinion, the Court stated:

> We note that jurisdictions have generally dealt with the allocation of cancelled plant costs in one of the following three ways: (1) recovery of all of the costs from ratepayers, by allowing amortization of the investment plus a return on the unamortized balance; (2) recovery of all costs from shareholders through a total disallowance of recovery in rates, instead requiring the utility to write off the entire amount in a single year; or (2) recovery from ratepayers and shareholders through amortization of costs in rates over a period of years, with no return on the unamortized balance. Strong policy considerations support the Commission and commentators who have concluded that method three is the best of the three alternatives in that it promotes "an equitable sharing of the loss between ratepayers and the utility stockholders."

Id., 325 N.C. at 480, 385 S.E.2d at 460 (citations omitted).

The Thornburg I decision involved investment in cancelled plant, but the Commission applied the same method of recovery to costs associated with environmental remediation costs arising from decommissioned manufactured gas plants in the 1994 PSNC Order, where deferral and amortization was permitted without any rate of return on the unamortized balance, even though the Commission did not in its opinion make a finding of imprudence or mismanagement.[1] Finally,

[1] As noted in the passage quoted from Thornburg I, other states have taken different approaches, and that was also true in the series of decisions from the 1990s relating to manufactured gas plants. However, the Commission's decision not to allow a return on unamortized balances in the 1994 PSNC Order was not unique. Similar decisions were

in the present case itself, the Commission majority would permit the Company to recover certain extraordinary operating costs incurred in connection with a series of major storms but proposes not to allow any return on the unamortized balance of those costs. Again, disallowance of a return is not being justified by any finding that the Company had mismanaged its response to the storms. Because I consider the costs of permanent disposal of coal ash wastes to be an operating expense under G.S. §62-133(b)(3) I find these precedents particularly compelling.

Two additional considerations lead me to the view that the imposition of a mismanagement penalty in the amount established by the majority is not an adequate response to the evidence in this case. In earlier cases in which the Commission has determined that imposition of a penalty for mismanagement and poor service was appropriate, the Commission has often endeavored to identify the specific ways in which the utility has fallen short and, where possible, to quantify the financial consequences of the mismanagement or poor service. This has been done to ensure that the amount of the penalty is not disproportionate to the nature of the underlying acts or omissions at issue. In the present case, I am not able to make any clear connection between the amount selected for the penalty ($6 million a year for five years) and any particular actions or omissions by the Company. In part for this reason, I prefer an approach that attempts to explore and then quantify causal relationships between specific acts of mismanagement and imprudence, and the resulting financial loss or avoidable costs.

Third, and finally, I note that in past cases where the Commission has seen fit to impose a penalty for mismanagement, there has been a forward-looking element to the Commission's action; that is, the penalty was not merely a response to the utility's past actions, but was also designed to provide an incentive for the utility to correct errors and improve future service. In the present case the imposition of a generic penalty may do little to provide any additional incentive for better service by the Company in the future. As a result of the federal criminal plea agreement and the conditions of probation arising therefrom, the adoption of the CCR Rule, the enactment and implementation of CAMA, and the terms of the various settlement agreements embodied in judgments entered in DEQ administrative proceedings and private party lawsuits, the Company is now subject to a highly prescriptive and closely-monitored regime dictating the details of how it will manage coal ash wastes from this point forward. In addition, and unlike those instances where the Commission has imposed a penalty for poor service or mismanagement, the Company has been subjected to steep and punitive criminal fines, civil penalties, and costly administrative settlements all occasioned by its past actions.[1]

For all these reasons, I am unable to join the majority's imposition of what it calls a penalty for mismanagement. I would instead, and for the reasons previously set forth, disallow from cost recovery and exclude from rates the following amounts:

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made in some, but not all, other jurisdictions. E.g., Northern States Power Company, Docket No. G-002/GR-86-160, 1987 Minn. PUC Lexis (Minn. Pub. Util. Comm'n, Jan. 27, 1987); Chesapeake Utilities Corp., Docket No. 85-17, 1986 Del. PSC Lexis (Del. Pub. Serv. Comm'n. March 25, 1986).

[1] Although I am being repetitive in doing so, I believe it is important to state once again that the Company is not seeking in this case any recovery on account of any criminal or civil fines, penalties or forfeitures, nor is it permitted to do so. This is a point that has often been overlooked by opponents of the Company's proposal for cost recovery.

1. **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]** in preparation, transport, and offsite disposal costs incurred to remove wastes from the two impoundments at the L.V. Sutton plant for disposal at the Brickhaven site in Chatham County.

2. $6,693,390 in accelerated groundwater remediation costs incurred at the L.V. Sutton plant pursuant to the September 29, 2015, agreement with the North Carolina Department of Environmental Quality.

3. $9,500,000 in excess contractual costs for offsite disposal ofwastes from the Asheville plant.

4. All costs with respect to the permanent disposal of ash wastes from the three pre-1973 impoundments at the H.V. Lee Plant, which based on the evidence provided, I would determine to be $7,867,730 on a system-wide basis through December 31, 2016. This number would be adjusted to calculate the North Carolina retail allocation. The disallowance would extend to all costs from before and after January 1, 2017, related to the pre-1973 impoundments.

5. All costs with respect to the permanent disposal of ash waste from the four pre-1985 impoundments at the Cape Fear Plant, which in this case and based on the evidence provided, I would determine to be $8,265,810 on a system-wide basis through December 31,2016. This number would be adjusted to calculate the North Carolina retail allocation. The disallowance would extend to all costs from before and after January 1, 2017, related to the pre-1985 impoundments.

6. Defer to a regulatory asset account all costs sought in this case, totaling $35,237,688, for the three impoundments at the Mayo and Roxboro plants, for further determination at the Company's next general rate case, and after DEQ determination as to thesufficiency and adequacy of the closure plans submitted by theCompany.

For all remaining costs incurred for the period January 1, 2015, through October 31, 2017, I would permit deferral and amortization over a period of five years, the period requested by the Company, but with no return allowed on the unamortized balance, in accord with prior Commission policy and practice and not as a penalty. Finally, I would grant deferral accounting treatment for all future costs, except for those items disallowed as noted above, but the deferral account would not accrue a rate ofreturn.

/s/ Daniel G. Clodfelter

Commissioner Daniel G. Clodfelter

DOCKET NO. E-22, SUB 546

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina Pursuant to G.S. § 62-133.2 and Commission Rule R8-55 Regarding Fuel and Fuel-Related Costs Adjustments for Electric Utilities	))))))	ORDER APPROVING FUEL RIDERS AND NOTICE TO CUSTOMERS OF CHANGE IN RATES

BY THE CHAIRMAN: On January 25, 2018, the Commission issued its Order Deciding Contested Issues and Requiring Compliance Filing (Fuel Order) in Docket No. E-22, Sub 546. In the Fuel Order, the Commission approved the level of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina's (Company's) system fuel expense, $1,758,608,978, to be used to set the Company's prospective, or forward-looking, fuel factor (Rider A) for 2018. The Commission also approved the Company's North Carolina retail test period jurisdictional fuel expense over-collection, $5,450,950, including interest, and to be adjusted as appropriate to reflect an 11-month rate period and the adjusted North Carolina retail jurisdictional test period sales, 4,299,466,351 kilowatt hours (kWh) for purposes of calculating the experience modification factor (EMF) (Rider B), and concluded that it is appropriate to implement the final phase of the Company's under-recovery of $381,535 EMF (Rider B2) from the mitigation proposal approved by the Commission in Docket No. E-22, Sub 515.

In the Ordering Paragraphs to the Fuel Order, the Commission directed the Company to: (1) recalculate and file proposed fuel factor increments (Rider A), EMF decrements (Rider B), EMF increments (Rider B2), and the total net fuel factors, on a voltage-differentiated basis consistent with the Fuel Order, to be effective for an 11-month period beginning on February 1, 2018; (2) work with the Public Staff—North Carolina Utilities Commission (Public Staff) to verify the accuracy of the increments and decrements to the Company's fuel riders; (3) to prepare a joint proposed notice to customers of the rate rider adjustments approved by the Commission in the Fuel Order; and (4) to file this information in a proposed order approving the proposed riders and customer notice.

Consistent with these directives, on January 29, 2018, the Company made a compliance filing with the Commission that included revised fuel rider tariff sheets reflecting the rates for Rider A and EMF Riders B and B2 for an 11-month period beginning on February 1, 2018, together with supporting workpapers showing the calculation of the proposed riders, and a joint proposed Notice to Customers of Change in Rates (Customer Notice) that was developed by the Company and the Public Staff. The Company's compliance filing stated that the Public Staff agrees with the content of the Customer Notice and with the calculation of the proposed riders. The Company requested that the Commission issue an order approving the recalculated fuel adjustment riders and the Customer Notice on or before January 30, 2018, to allow the Company to implement the new fuel riders effective February 1, 2018.

ELECTRIC – ADJUSTMENTS OF RATES/CHARGES

As reflected in the Company's compliance filing and proposed Customer Notice, the proper fuel factors (Rider A) for use in this proceeding, including the regulatory fee, are as follows:

Customer Class	Rider A
Residential	0.006 ¢/kWh
SGS & PA	0.006 ¢/kWh
LGS	0.003 ¢/kWh
Schedule NS	0.006 ¢/kWh
6VP	0.006 ¢/kWh
Outdoor Lighting	0.006 ¢/kWh
Traffic	0.006 ¢/kWh

The appropriate EMF (Rider B) for this proceeding, including interest and the regulatory fee, are as follows:

Customer Class	EMF Billing Factor
Residential	(0.141) ¢/kWh
SGS & PA	(0.141) ¢/kWh
LGS	(0.140) ¢/kWh
Schedule NS	(0.136) ¢/kWh
6VP	(0.137) ¢/kWh
Outdoor Lighting	(0.141) ¢/kWh
Traffic	(0.141) ¢/kWh

The appropriate EMF (Rider B2) factors for this proceeding, including the current regulatory fee, are as follows:

Customer Class	EMF Billing Factor
Residential	0.011 ¢/kWh
SGS & PA	0.011 ¢/kWh
LGS	0.010 ¢/kWh
Schedule NS	0.010 ¢/kWh
6VP	0.010 ¢/kWh
Outdoor Lighting	0.011 ¢/kWh
Traffic	0.011 ¢/kWh

Finally, the total net fuel factors (¢/kWh), with regulatory fee, are as follows:

Customer Class	Total Net Fuel Factor
Residential	1.971 ¢/kWh
SGS & PA	1.969 ¢/kWh
LGS	1.952 ¢/kWh

Schedule NS	1.894 ¢/kWh
6VP	1.922 ¢/kWh
Outdoor Lighting	1.971 ¢/kWh
Traffic	1.971 ¢/kWh

Based on the foregoing and the record, the Chairman finds good cause to approve the recalculated fuel factor riders and the Customer Notice filed by the Company on January 29, 2018, and to direct that the Company give notice to its customers using the format of the Customer Notice attached hereto as Attachment A.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 30th day of January, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

ATTACHMENT A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-22, SUB 546

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina Pursuant to G.S. 62-133.2 and Commission Rule R8-55 Regarding Fuel and Fuel-Related Costs Adjustments for Electric Utilities	NOTICE TO CUSTOMERS OF CHANGE IN RATES

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission (Commission) has authorized Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (Company), to implement an overall increase in its fuel rates and charges paid by customers for retail electric service in North Carolina, as detailed below, to recover an increase in the Company's total fuel expenses, to refund through an experience modification factor (EMF) over-collection of retail fuel expense, and to collect non-base fuel revenues associated with EMF revenues. The Commission's Orders authorizing these rate changes were issued on January 25 and 30, 2018, in Docket No. E-22, Sub 546.

The Commission approved annual non-base fuel rate changes to become effective February 1, 2018, including a projected fuel factor (Rider A), EMF Rider B designed to refund \$5,450,950 (including interest, and to be adjusted as appropriate to reflect an 11-month rate period) due to over-collection in the prior period, and EMF Rider B2 designed to collect \$381,535 in unrecovered expenses related to Docket No. E-22, Sub 515. The overall fuel rate increase was approved by the Commission after review of the Company's fuel expenses and related revenues during the 12-month period ending on June 30, 2017, and represents changes experienced by the Company with respect to its reasonable costs of fuel and the fuel component of purchased power.

The increments in forward fuel factors (Rider A) approved by the Commission are: Residential – 0.006 ¢/kWh; SGS & Public Authority – 0.006 ¢/kWh; LGS – 0.003 ¢/kWh; NS – 0.006 ¢/kWh; 6VP – 0.006 ¢/kWh; Outdoor Lighting – 0.006 ¢/kWh; and Traffic – 0.006 ¢/kWh.

The EMF decrement fuel factors (Rider B) approved by the Commission are: Residential – (0.141) ¢/kWh; SGS & Public Authority – (0.141) ¢/kWh; LGS – (0.140) ¢/kWh; NS – (0.136) ¢/kWh; 6VP – (0.137) ¢/kWh; Outdoor Lighting – (0.141) ¢/kWh; and Traffic – (0.141) ¢/kWh.

The EMF increment fuel factors (Rider B2) approved by the Commission are: Residential – 0.011 ¢/kWh; SGS & Public Authority – 0.011 ¢/kWh; LGS – 0.010 ¢/kWh; NS – 0.010 ¢/kWh; 6VP – 0.010 ¢/kWh; Outdoor Lighting – 0.011 ¢/kWh; and Traffic – 0.0141 ¢/kWh.

All factors are based on an 11-month rate period as directed by the Commission in this proceeding.

The net change in the EMF rates and Fuel Rider A will result in a monthly increase of approximately \$3.49 for a residential customer using 1,000 kWh per month during the period February 1, 2018, through December 31, 2018, as compared to 2017 fuel rates. The total monthly impact for commercial and industrial customers will vary based upon consumption and customers' participation in Dominion Energy North Carolina's demand-side management and energy-efficiency programs.

Dominion Energy North Carolina's total net fuel factors for each customer class are: Residential – 1.971¢/kWh; SGS & Public Authority – 1.969¢/kWh; LGS – 1.952¢/kWh; NS – 1.894¢/kWh; 6VP – 1.922¢/kWh; Outdoor Lighting – 1.971¢/kWh; and Traffic – 1.971¢/kWh.

The Commission's Order directed the Company to bill these amounts during the period February 1, 2018, through and including December 31, 2018.

ISSUED BY ORDER OF THE COMMISSION.
This the 30th day of January, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

DOCKET NO. E-34, SUB 47

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Appalachian State University,	)	ORDER APPROVING 2018
d/b/a NRLP Light and Power Company, for	)	PURCHASE POWER ADJUSTMENT
Approval of 2018 Purchase Power	)	FACTOR AND 2018 COAL ASH
Adjustment Factor and 2018 Coal Ash	)	COST RECOVERY RIDER
Cost Recovery Rider	)	

BY THE COMMISSION: On October 2, 2017, Appalachian State University, d/b/a NRLP Light and Power Company (NRLP) filed its preliminary Purchased Power Adjustment (PPA) for 2018. NRLP purchases energy and capacity from Blue Ridge Electric Membership Corporation (BREMCO), who purchases its energy and capacity from Duke Energy Carolinas, LLC (DEC). NRLP's yearly PPA adjustment process was authorized by the Commission's Order Approving Rate Increase and Annual Procedure issued on December 22, 2010, in Docket No. E-34, Sub 38 (Sub 38 Order). NRLP enclosed in its preliminary filing a proposed adjustment to the PPA factor of $0.020344 per kilowatt-hour (kWh), excluding the North Carolina regulatory fee, or $0.020372 per kWh, including the regulatory fee. NRLP requested that this PPA factor be included in rates for bills rendered after February 1, 2018.[1]

On January 12, 2018, the Public Staff filed a motion for extension of time, requesting that the Commission extend the effective date for NRLP's 2018 PPA factor from February 1, 2018 to April 1, 2018. In support of its requested extension, the Public Staff first noted that on June 30, 2017, NRLP filed an application for a general rate increase in Docket No. E-34, Sub 46 (NRLP's General Rate Case). The Public Staff also stated that it and NRLP are engaged in settlement negotiations with regard to the issues in NRLP's General Rate Case, including the proper mechanism for including coal ash cleanup costs in NRLP's rates. Further, the Public Staff stated that the annual PPA filing that is the subject of this proceeding includes, for the first time, certain coal ash cleanup costs incurred by DEC, passed on to BREMCO, and charged to NRLP by BREMCO during 2017.

On January 19, 2018, the Commission issued an Order Granting Extension of Time, extending the date on which NRLP's 2018 PPA factor shall become effective from February 1, 2018, to April 1, 2018, as requested by the Public Staff.

Also on January 19, 2018, in NRLP's General Rate Case, NRLP and the Public Staff filed a stipulation, settling all issues between them in that proceeding. Among the issues that NRLP and the Public Staff have agreed to in NRLP's General Rate Case are 1) that it is appropriate and reasonable for the current procedure and method used to determine the annual PPA rider to

[1] On January 23, 2014, in Docket No. E-34, Sub 41, the Commission issued an Order establishing February 1 as the date that NRLP's PPA factor becomes effective. This date was chosen to provide NRLP sufficient time to incorporate its final bill from BREMCO for the preceding calendar year in its PPA factor. Since that time, the procedure has been for NRLP to file its preliminary PPA in October, and its new PPA has gone into effect for service rendered on and after February 1 of the next year.

continue, and, if approved by the Commission, the annual PPA rider can be determined without the requirement that NRLP's ongoing earnings be considered as part of the annual PPA rider determination. NRLP and the Public Staff also agreed that the appropriate base purchased power cost factor reflected in their agreement, which should be established in NRLP's General Rate Case for use in future PPA Rider proceedings is $0.062846 per kWh (excluding the North Carolina regulatory fee); and 2) that NRLP should be allowed to begin recovering reasonable and appropriate coal ash costs charged to it by BREMCO through a separate rider or separate component of NRLP's PPA rider. NRLP and the Public Staff further agreed that the coal ash cost recovery (CACR) rider should be implemented concurrent with this proceeding and future similar proceedings. NRLP and the Public Staff also agreed that the appropriate base CACR rider for use in future CACR rider proceedings is $0.000000 per kWh (excluding the North Carolina regulatory fee).

On March 20, 2018, NRLP filed its final proposed 2018 PPA factor, including an experience modification factor (EMF) based on total actual purchased power revenues and costs for the period January through December 2017. The 2018 PPA factor NRLP requests in this filing is $0.001005 per kWh (excluding the regulatory fee), consisting of two elements: 1) an estimated decrement in purchased power costs for the period January through December 2018 of ($0.000880) per kWh, and 2) an EMF increment of $0.001885 per kWh. NRLP states that when calculated to include the regulatory fee, the PPA factor totals $0.001006 per kWh, which results in an increase in total purchased power rates of $0.001006 per kWh above the base purchased power revenues recommended in NRLP's General Rate Case. Thus, NRLP requests that the Commission approve the 2018 PPA factor of $0.001006 per kWh as an adjustment from the base purchase power cost rate of $0.062846 per kWh.[1] NRLP requested that the new rates be approved for all service rendered on or after April 1, 2018.

In its March 20, 2018 filing, NRLP proposes to revise each of its retail rate schedules as agreed to by NRLP and the Public Staff in NRLP's General Rate Case, including its outdoor lighting schedules, by incorporating the $0.001006 per kWh PPA factor. The Company states that its proposed PPA factor, if approved by the Commission, will increase rates for its customers over the base rates established in NRLP's General Rate Case by a range of 1.0% (for residential customers) to 1.4% (for large commercial customers).

Also in its March 20, 2018 filing, NRLP requested approval of a CACR rider, with a CACR base factor of $0.000000, as agreed to by NRLP and the Public Staff in their stipulation filed in NRLP's General Rate Case. NRLP's proposed 2018 CACR factor estimate is $0.003246 per kWh (excluding the North Carolina regulatory fee), or $0.003251 per kWh (including the North Carolina regulatory fee). NRLP states that it has determined this estimate by dividing its current estimate of total coal ash costs through 2021, dividing that amount by 44 months, and then multiplying that monthly average by 12 months. This estimate, with any appropriate interest calculated, will be subject to true-up in future NRLP PPA/CACR rider proceedings. The Company states that its proposed CACR factor, if approved by the Commission, will increase rates for its

[1] Contemporaneous with the issuance of this order, the Commission has issued an Order in NRLP's General Rate Case, approving the stipulation between NRLP and the Public Staff. Among other things, that Order approves the base purchased power cost rate of $0.062846 per kWh, as agreed to by NRLP and the Public Staff in their stipulation filed in NRLP's General Rate Case.

customers over the NRLP's General Rate Case base rates by a range of 3.1% (for residential customers) to 4.6% (for commercial demand high load factor customers).

The Public Staff presented this matter at the Commission's regular Staff Conference on March 26, 2018, stating that it had reviewed NRLP's calculations for the PPA, and determined that the proposed PPA has been calculated accurately and in a reasonable manner, given the projections of purchased power costs received from BREMCO, and is consistent with previous NRLP pass through requests approved by the Commission. Furthermore, pursuant to the provision of the Sub 38 Order that each annual PPA factor adjustment should take into consideration, as appropriate, NRLP's overall level of earnings and return on rate base at that time, the Public Staff has also conducted a review of NRLP's 2017 earnings. For purposes of this proceeding, this review has been accomplished by virtue of the Public Staff's investigation in NRLP's General Rate Case. Based on the results of its review, the Public Staff concluded that the requested PPA is appropriate and reasonable in that it is based solely on the level of purchased power expense expected to be incurred by NRLP (including the EMF), and when combined with the Public Staff's findings in its general rate case investigation, does not appear to be unreasonable overall. The Public Staff further states that it reviewed the components and calculations of the estimated coal ash costs that NRLP seeks to collect from its retail customers through the CACR rider, and, based on its review, the Public Staff recommends that the Commission approve the 2018 CACR factor as proposed.

Based on the foregoing and the entire record herein, the Commission finds good cause exists to approve the proposed 2018 PPA factor and 2018 CACR rider, allowing NRLP to recover through retail rates charged to its customers the increased cost of purchased power and coal ash cleanup, respectively. The Commission further finds good cause to approve the proposed 2018 PPA factor and 2018 CACR rider without public hearing, subject to refund of any amounts subsequently found to be unjust or unreasonable upon protest and hearing as is allowed in the notice to customers attached hereto as Appendix A.

IT IS, THEREFORE, ORDERED as follows:

1. That, effective with service rendered on and after April 1, 2018, NRLP is authorized to adjust its rates and charges to reflect a 2018 PPA factor of $0.001005 per kWh (excluding the regulatory fee) and $0.001006 per kWh (including the regulatory fee), resulting in an increase of $0.001006 per kWh in the PPA factor;

2. That, effective with service rendered on and after April 1, 2018, NRLP is authorized to implement a 2018 CACR rider of $0.003246 per kWh (excluding the regulatory fee) and $0.003251 per kWh (including the regulatory fee);

3. That the rates authorized by this order are subject to refund of any amounts which may subsequently be found unjust and unreasonable after public hearing, which may be held as provided in the Notice to Customers attached hereto as Appendix A;

4. That, within 10 days of this order, NRLP shall file copies of its approved rates and charges, as modified herein; and

5. That, within seven days of the date of this order, NRLP shall mail by separate mail or bill insert the Notice to Customers attached hereto as Appendix A to each of its customers, and publish, at its own expense, in newspapers having general circulation in its North Carolina service area once a week for two consecutive weeks. The first publication of the Notice to Customers shall appear not later than seven days following the date of this Order, and cover no less than one-quarter of a page. Within 10 days of the last date of mailing or publication, whichever is later, NRLP shall affidavits evidencing compliance with the requirements of this ordering paragraph.

ISSUED BY ORDER OF THE COMMISSION.
This the 29th day of March, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

Commissioners Jerry C. Dockham and Charlotte A. Mitchell did not participate in this decision.

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

NOTICE TO CUSTOMERS

DOCKET NO. E-34, SUB 47
BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

Notice is hereby given that New River Light and Power Company (NRLP) has requested that the North Carolina Utilities Commission (Commission) approve an adjustment to its purchased power adjustment (PPA) factor, and the establishment of a coal ash cost recovery (CACR) factor, for service rendered on and after April 1, 2018, to pass through to its customers the increased cost of purchased power and coal ash cleanup costs from its wholesale power supplier, Blue Ridge Electric Membership Corporation (BREMCO).

The amount of the increase to NRLP's customers resulting from the new PPA and CACR factors will be approximately $873,000 per year, an increase of approximately 4.6%. The increase will be applied to NRLP's customers as uniform increases to the kilowatt-hour (kWh) energy charge. The increment in revenue produced by the increase will be the same as the increase in the cost of purchased power and coal ash cleanup from BREMCO, adjusted for the effects of the utility regulatory fee. The proposed increases of $0.001006 per kWh (PPA) and $0.003251 per kWh (CACR) will result in an increase in the monthly bill of a residential customer using 1,000 kWh from $103.35 to $107.60. The approximate percentage increases in customers' bills, by rate schedule, are as follows (actual percentages may differ depending on specific customers' usage amounts):

Residential	4.1%
Schedule G (Commercial)	4.3%
Schedule GL (Large Commercial)	5.0%
Schedule GLH (Commercial Demand High Load Factor)	6.0%
Schedule A (App. State Univ.)	5.3%

The Commission has concluded that the PPA and CACR requested by NRLP are reasonable, in that they are based solely on the level of purchased power and coal ash cleanup expense expected to be incurred by NRLP.

Therefore, the Commission has approved NRLP's requests without public hearing, subject to refund of any amounts which should subsequently be found to be unjust or unreasonable after any public hearing in this matter that may subsequently be held by the Commission, as described below.

Persons desiring to intervene in this matter as formal parties of record should file a motion under Commission Rules R1-6, R1-7, and R1-19 not later than 45 days after the date of this notice. Persons desiring to present testimony or evidence at a hearing should so advise the Commission. Persons desiring to send written statements to inform the Commission of their position in the matter should address their statements to the Chief Clerk, North Carolina Utilities Commission, 4325 Mail Service Center, Raleigh, North Carolina 27699-4300. However, such written statements cannot be considered competent evidence unless those persons appear at a public hearing and testify concerning the information contained in their written statements. If a significant number of requests for a public hearing are received within 45 days after the date of this notice, the Commission may schedule a public hearing.

The Public Staff – North Carolina Utilities Commission is authorized by statute to represent the using and consuming public in proceedings before the Commission. Written statements to the Public Staff should include any information which the writer wishes to be considered by the Public Staff in its investigation of the matter, and such statements should be addressed to Christopher J. Ayers, Executive Director, Public Staff, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300.

ISSUED BY ORDER OF THE COMMISSION.
This the 29th day of March, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

DOCKET NO. E-35, SUB 48

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Western Carolina University for Authority to Recover Purchased Power Expense	)))	ORDER APPROVING PURCHASED POWER COST RIDER

BY THE COMMISSION: On December 15, 2017, in compliance with Commission orders in Docket No. E-35, Subs 17, 19, and 40, respectively, Western Carolina University (WCU) filed an application for a change in its Schedule CP Purchased Power Cost Rider (Rider) to be effective for the twelve monthly billings beginning with the bills rendered in January 2018. This filing included actual purchased power cost and recovery information only for the period January 2017 through November 2017. On January 19, 2018, the Commission issued an Order Granting Extension of Time in this proceeding, providing that the date on which WCU's 2018 PPA factor shall become effective would be extended by one month. On February 13, 2018, WCU filed its final rates for the Rider, which incorporated actual purchased power costs and revenues through December 2017.

The net purchased power adjustment factor requested by WCU for use in Schedule CP is an increment of $0.00155 per kWh. This proposed factor would replace the currently expiring decrement factor of $(0.00488) and would thus result in a net increase, relative to current rates, in a customer's monthly bill by $6.43 for 1,000 kWh of usage. The requested factor is made up of two elements. The first is a decrement of $(0.00092) per kWh to recover, in conjunction with purchased power revenues included in base rates, estimated purchased power costs for the period February 2018 through December 2018. The second element is an Experience Modification Factor (EMF) increment of $0.00247 per kWh to collect purchased power costs undercollected during the period January 2017 through December 2017.

The Public Staff presented this matter at the Commission's Regular Staff Conference on February 19, 2018, and recommended that the proposed Rider increment be approved effective for the eleven monthly bills rendered on and after February 19, 2018, and before January 1, 2019. In support of this recommendation, the Public Staff stated that it had reviewed the calculations and documentation supporting the Rider requested by WCU and found them to be accurate.

The Public Staff also stated that both the 2018 estimated and the 2017 actual rider amounts include charges actually or expected to be billed at wholesale to WCU by its power supplier, Duke Energy Carolinas, LLC (DEC), for coal ash cleanup costs at DEC's generation facilities. Pursuant to certain sections of WCU's power purchase contract with DEC, these costs may be subject to adjustment based on the outcome of DEC's currently ongoing general rate case proceeding, Docket No. E-7, Sub 1146 (Sub 1146). If such adjustments in charges by DEC occur, WCU plans to flow through those adjustments to its retail customers in future Schedule CP Riders. With regard to the estimated component of the Rider proposed in this proceeding, WCU proposes to defer 50% of the coal ash cleanup costs included therein, to be recovered in the EMF component of next year's Rider (as trued up to actual), but still subject to the ultimate outcome of the Sub 1146 proceeding.

In this case, the deferred estimate amount equals approximately $94,000. The Public Staff indicated that it does not object to this proposal.

Furthermore, the Public Staff stated that it and WCU had also discussed a reasonable amount of carrying costs for the deferred coal ash cleanup estimate, and have agreed that it is reasonable for WCU to calculate carrying costs typically for one year (but only 11.5 months in this case, due to the one-month delay approved by the Commission), at the Federal Energy Regulatory Commission (FERC) interest rate (currently 4.25% annually) as set forth in Section 35.19a of the FERC Regulations and published quarterly, but in no event at a rate greater than the weighted overall rate of return approved in WCU's most recent general rate case. The carrying costs would be calculated and added to the Rider as part of the EMF true-up of the applicable deferred coal ash cleanup estimate (in this case in next year's Rider). The Public Staff stated that it recommends that the Commission approve this method of calculating carrying costs.

Finally, the Public Staff stated that the approval of this Rider should be without prejudice to the right of any party to take issue with it or the Commission's conclusions regarding the deferral of coal ash cleanup costs in a general rate case.

After careful review of WCU's proposal and based upon the recommendation of the Public Staff, the Commission concludes that the PPA factor increment of $0.00155 per kWh proposed by WCU should be approved. The Commission also concludes that WCU's request to defer 50% of the coal ash cleanup costs included in the estimated component of its proposed Schedule CP Rider, with future true-ups as discussed in this Order, is reasonable and should be approved. Finally, the Commission concludes that the method recommended by WCU and the Public Staff for calculating and applying carrying costs to the deferred estimated coal ash cleanup costs is reasonable and should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That WCU's Purchased Power Cost Rider, Schedule CP, which is attached to this order as Attachment A, is allowed to become effective for the eleven monthly bills rendered on and after February 19, 2018, and before January 1, 2019.

2. That WCU shall give appropriate notice to its retail customers for the Purchased Power Cost Rider by bill insert in the bills issued in February 2018. A copy of this notice shall be filed with the Chief Clerk of the North Carolina Utilities Commission within five working days of the date of this Order.

3. That WCU shall file appropriate rate schedules and riders with the Commission in order to implement the approved purchased power adjustment no later than ten working days from the date of this Order.

4. That WCU's request to defer 50% of the coal ash cleanup costs included in the estimated component of its proposed Schedule CP Rider, with future true-ups, as discussed in this Order, is hereby approved.

5. That the method recommended by WCU and the Public Staff for calculating and applying carrying costs to the deferred estimated coal ash cleanup costs, as discussed in this Order, is hereby approved.

6. That the Purchased Power Cost Rider is approved without prejudice to the right of any party to take issue with it or the Commission's conclusions regarding the deferral of coal ash cleanup costs in a general rate case.

ISSUED BY ORDER OF THE COMMISSION.
This the __21st__ day of February, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

Commissioner Daniel G. Clodfelter dissents.
Commissioner Charlotte A. Mitchell did not participate in this decision.

ATTACHMENT A

WESTERN CAROLINA UNIVERSITY
DOCKET NO. E-35, SUB 48

SCHEDULE "CP"
PURCHASED POWER COST RIDER

Each customer's eleven monthly bills rendered on and after February 19, 2018, for each month between February 19, 2018, and January 1, 2019, shall be adjusted by an incremental charge of $0.00155 per kWh as determined to be appropriate by the North Carolina Utilities Commission.

This rate is determined as follows:a

	$/kWh
Factor for estimated purchased power costs for the period February 2018 through December 2018	($0.00092)
Experience Modification Factor to reflect actual results for the period January 2017 through December 2017	$0.00247
TOTAL RATE	$0.00155

Effective for bills rendered on and after February 19, 2018 and before January 1, 2019.

DOCKET NO. E-2, SUB 1158

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Energy Progress, LLC, for a Certificate of Environmental Compatibility and Public Convenience and Necessity and Motion for Waiver of Notice and Hearing Pursuant to N.C. G.S. 62-100 et seq. to Construct Approximately 350 feet of New 230 kV Transmission Line in Pitt County, North Carolina	ORDER WAIVING NOTICE AND HEARING REQUIREMENT AND ISSUING CERTIFICATE

BY THE COMMISSION: On June 12, 2017, pursuant to G.S. 62-101 and G.S. 62-102, and Commission Rule R8-62(k), Duke Energy Progress, LLC (DEP or the Company), prefiled with the Commission an application for a certificate of environmental compatibility and public convenience and necessity to construct a new 230-kV transmission tap line approximately 350 feet in length, and a 230-kV breaker station (Tap Line) in Pitt County, North Carolina to serve a new 50 megawatt (MW) solar photovoltaic electric generating facility to be constructed by Cypress Creek Renewables (CCR). Shoe Heel Creek Solar, LLC, an affiliate of CCR, was issued a certificate of public convenience and necessity to construct the generating facility by Order Issued December 1, 2015 in Docket No. SP-5275, Sub 0. The prefiled application stated that the proposed Tap Line will connect the new solar facility to DEP's existing Greenville – Kinston Dupont 230-kV transmission line. CCR will build a new 230kV/34.5kV substation that will be placed adjacent to the DEP breaker station. Included in the prefiled application was a motion for waiver of the notice and hearing requirements of G.S.62-102, G.S. 62-104, and Commission Rule R8-62, as provided for in G.S. 62-101(d)(1). As detailed in DEP's prefiled certificate application, the Company will construct the Tap Line on property for which it has purchased the right of way from the property owner, and the property owner does not object to a waiver of the hearing and notice requirements of G.S. 62-102 and G.S. 62-104.

On December 6, 2017, DEP formally filed the application for a certificate and motion for waiver of notice and hearing.

G.S. 62-101(d)(1) authorizes the Commission to waive the notice and hearing requirements of G.S. 62-102 and G.S. 62-104 when it finds that the owners of the land to be crossed by the proposed transmission line do not object to the waiver and either the transmission line is less than one mile long or to connect an existing transmission line to a substation, to another public utility, or to a public utility customer when any of these is in proximity to the existing transmission line. The application states that the Company will construct the Tap Line on property for which it has acquired an easement from the property owner whose land will be crossed by the Tap Line, the property owner does not object to the waiver of notice or hearing, and that the total length of the line is approximately 350 feet. Thus, the conditions of G.S. 62-101(d)(1) for a waiver of notice and hearing have been met. The application is also supported by a Certificate Application Report. This report satisfies the requirements of G.S. 62-102(a).

ELECTRIC – ELECTRIC TRANSMISSION LINE CERTIFICATE

The Public Staff presented this matter at the Commission's regular Staff Conference on January 8, 2018. The Public Staff stated that the application meets the requirements of G.S. 62-102 and Commission Rule R8-62 for a certificate and the conditions of G.S. 62-101(d)(1) for waiver of the notice and hearing requirements of G.S. 62-102 and G.S. 62-104. The Public Staff recommended that the Commission grant the motion for waiver and issue the requested certificate.

Based on the foregoing and the recommendation of the Public Staff, the Commission finds and concludes that the notice and hearing requirements of G.S. 62-102 and G.S. 62-104 should be waived as allowed by G.S. 62-101(d)(1) and that a certificate of environmental compatibility and public convenience and necessity should be issued for the proposed construction of a new 230-kV transmission tap line.

IT IS, THEREFORE, ORDERED as follows:

1. That, pursuant to G.S. 62-101, the requirement for publication of notice and hearing is waived; and

2. That, pursuant to G.S. 62-102, a Certificate of Environmental Compatibility and Public Convenience and Necessity to construct approximately 350 feet of new 230-kV transmission line in Pitt County, North Carolina, as described in DEP's application is issued, and the same is attached as Appendix A.

ISSUED BY ORDER OF THE COMMISSION.
This the 8th day of January, 2018

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

Commissioner Jerry C. Dockham did not participate in this decision.

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1158

Know All Men by These Presents, That

DUKE ENERGY PROGRESS, LLC

is hereby issued this

CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY AND PUBLIC CONVENIENCE AND NECESSITY PURSUANT TO G.S. 62-102

to construct approximately 350 feet of new 230-kV transmission line to connect Cypress Creek Renewables' solar facility to the DEP Greenville – Kinston Dupont 230-kV transmission line in Pitt County, North Carolina

subject to receipt of all federal and state permits as required by existing and future regulations prior to beginning construction and further subject to all other orders, rules, regulations, and conditions as are now or may hereafter be lawfully made by the North Carolina Utilities Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 8th day of January, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

DOCKET NO. E-22, SUB 551
DOCKET NO. G-5, SUB 585

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Joint Application of Dominion Energy, Inc. and SCANA Corporation to Engage in a Business Combination Transaction	))))	ORDER APPROVING MERGER SUBJECT TO REGULATORY CONDITIONS AND CODE OF CONDUCT

HEARD: On October 10, 2018, in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

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

APPEARANCES:

For Dominion Energy, Inc.:

Joseph K. Reid, II, McGuireWoods, LLP, Gateway Plaza, 800 East Canal Street, Richmond, Virginia 23219

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

Andrea R. Kells, McGuireWoods, LLP, 434 Fayetteville Street, Suite 2600, Raleigh, Charlotte, North Carolina 27601

Lisa Booth, Dominion Energy Services, Inc., 120 Tredegar Street, Richmond, Virginia 23261

For SCANA Corporation:

Joseph K. Reid, II, McGuireWoods, LLP, Gateway Plaza, 800 East Canal Street, Richmond, Virginia 23219

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

Andrea R. Kells, McGuireWoods, LLP, 434 Fayetteville Street, Suite 2600, Raleigh, North Carolina 27601

Craig Collins, SCANA Services, Inc., 220 Operation Way, Cayce, South Carolina 29033

For the Carolina Industrial Group for Fair Utility Rates I:

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

For Transcontinental Gas Pipe Line Company, LLC:

Dwight Allen, The Allen Law Offices, 1514 Glenwood Avenue, Suite 200, Raleigh, North Carolina 27608

Brady Allen, The Allen Law Offices, 1514 Glenwood Avenue, Suite 200, Raleigh, North Carolina 27608

For the Using and Consuming Public:

Gina C. Holt, Staff, Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699

Robert Josey, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699

BY THE COMMISSION: On January 24, 2018, pursuant to N.C. Gen. Stat. § 62- 111(a) and Commission Rule R1-5, Dominion Energy, Inc. (Dominion Energy) and SCANA Corporation (SCANA) (collectively referred to hereinafter as Applicants), filedan application (Application) for authorization to engage in a business combination transaction (Merger). The Application included a copy of the Agreement and Plan of Merger between Dominion Energy and SCANA (Merger Agreement) as well as a cost- benefit analysis (Cost-Benefit Analysis) and a market power analysis (Market Power Analysis) as required by the Commission's Order Requiring Filing of Analyses, issued November 2, 2000, in Docket No. M-100, Sub 129 (M 100, Sub 129 Order).

On June 22, 2018, the Applicants filed the testimony of Thomas F. Farrell, II, Jimmy E. Addison, D. Russell Harris, Craig C. Wagstaff, James R. Chapman, and David Hunger. An updated exhibit JRC-1 to the testimony of James R. Chapman was subsequently filed on July 20, 2018.

On June 19, 2018, the Commission issued its Order Scheduling Hearing, Establishing Procedural Deadlines, and Requiring Public Notice (Scheduling Order). The Scheduling Order, among other things, established a hearing date of October 10, 2018, set prefiled testimony dates, and required the Applicants to give notice to their customers of the hearing in this matter. In addition, the Scheduling Order found and concluded that the Application satisfied the requirements of the M-100, Sub 129 Order.

Petitions to intervene were filed by Carolina Industrial Group for Fair Utility Rates I (CIGFUR I), North Carolina Sustainable Energy Association (NCSEA), and Transcontinental Gas Pipe Line Company, LLC (Transco). By separate orders, the Commission granted these petitions to intervene. The intervention of the Public Staff – North Carolina Utilities Commission (Public Staff) is recognized pursuant to N.C. Gen. Stat. § 62-15(d) and Commission Rule R1-19(e).

Limited admission to practice before the Commission was granted to out-of-state attorneys for Dominion Energy and SCANA.

On August 23, 2018, Applicants filed affidavits of publication of notice to customers of the hearing.

On September 27, 2018, the Public Staff filed the direct testimony and exhibits of Michael C. Maness, Jan A. Larsen, James S. McLawhorn, and John R. Hinton (Public Staff Panel).

On September 27, 2018, Transco filed the testimony and exhibits of Camilo Amezquita.

On October 4, 2018, the Applicants filed an Agreement and Stipulation of Settlement (Stipulation) between the Applicants, Transco, and the Public Staff (Stipulating Parties), which included stipulated Regulatory Conditions and a Code of Conduct.

On October 5, 2018, the Applicants filed black-line versions of the Proposed Regulatory Conditions and Code of Conduct filed by the Public Staff with its testimony on September 27, 2018, compared to the Proposed Regulatory Conditions and Code of Conduct filed by the Stipulating Parties on October 4, 2018.

On October 5, 2018, the Applicants filed supplemental testimony of Thomas P. Wohlfarth and D. Russell Harris in support of the Stipulation.

On October 5, 2018, Dominion Energy, SCANA, Transco, and the Public Staff filed a Joint Motion to Excuse Witnesses, which was granted in part by order of the Commission issued October 8, 2018.

On October 5, 2018, pursuant to the Scheduling Order, the Applicants filed the Joint List and Order of Witnesses.

On October 8, 2018, the Public Staff filed revised testimony of the Public Staff Panel.

On October 10, 2018, the Public Staff filed revised versions of the Regulatory Conditions and Code of Conduct, revising those that had been attached as Attachment A to the Stipulation filed on October 4, 2018.

The matter came for hearing on October 10, 2018, as scheduled. No public witnesses appeared to offer testimony. The pre-filed testimony and exhibits of the following party witnesses were received into evidence:

<u>For the Applicants</u>: Thomas F. Farrell, II, Chairman, President and Chief Executive Officer of Dominion Energy; Jimmy E. Addison, Chief Executive Officer of SCANA; D. Russell Harris, President and Chief Operating Officer of PSNC, President of Gas Operations for SCE&G, and President of SCANA Energy Marketing, Inc.; Craig C. Wagstaff, President of Gas Distribution of Dominion Energy; James R. Chapman, Senior Vice President, Mergers and Acquisitions and Treasurer of Dominion Energy; Thomas P. Wolfarth, Senior

Vice President of Regulatory Affairs of Dominion Energy; David Hunger, Vice President of Charles River Associates.

For the Public Staff: Michael C. Maness, Director, Accounting Division; Jan A. Larsen, Director, Natural Gas Division; James S. McLawhorn, Director, Electric Division; John R. Hinton, Director, Economic Research Division.

For Transco: Camilo Amezquita.

At the hearing, the Application and exhibits thereto, as well as the Stipulation and the revised proposed Regulatory Conditions and Code of Conduct as filed on October 4, 2018, and October 10, 2018, were entered into the record without objection.

On October 31, 2018, the Applicants filed responses to Commission questions which were included in the October 8, 2018 Order Granting in Part Motion to Excuse Several Witnesses and Requiring Late-Filed Exhibit.

On October 31, 2018, Applicants and the Public Staff filed a Joint Proposed Order.

On November 9, 2018, Applicants and the Public Staff filed a revised Code of Conduct.

Based on the foregoing, the testimony and exhibits presented at the hearing of this matter, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

Jurisdiction

1. Dominion Energy is a corporation duly organized and existing under the laws of Virginia and is headquartered in Richmond, Virginia. Virginia Electric and Power Company is a wholly-owned subsidiary of Dominion Energy that does business in North Carolina as Dominion Energy North Carolina (DENC).

2. DENC is headquartered in Richmond, Virginia, and is engaged in the business of generating, transmitting, and distributing electricity in its service territories in Virginia and North Carolina. It serves approximately 120,000 customers in northeastern North Carolina. DENC also provides power and/or transmission services to the North Carolina Electric Membership Corporation, the North Carolina Eastern Municipal Power Agency, and the Town of Windsor, which in turn provide service to approximately 100,000 customers.

3. DENC is a public utility under the laws of North Carolina and its respective public utility operations are subject to the jurisdiction of this Commission.

4. Dominion Energy also owns gas utility subsidiaries in Ohio, West Virginia, Utah, Wyoming, and Idaho – Dominion Energy Ohio, Dominion Energy West Virginia, Dominion Energy Utah, Dominion Energy Wyoming, and Dominion Energy Idaho – which collectively provide service to 2.3 million distribution customers in those states.

5. Dominion Energy is also the sole owner of Sedona Corp. (Sedona), a South Carolina corporation and wholly-owned subsidiary of Dominion Energy formed for the purpose of effectuating the business combination transaction with SCANA. Sedona is not a public utility in North Carolina or elsewhere.

6. SCANA is a South Carolina corporation and a publicly-held holding company, whose principal subsidiaries are Public Service Company of North Carolina, Incorporated (PSNC), South Carolina Electric & Gas Company (SCE&G), and SCANA Energy Marketing, Inc.

7. PSNC is a corporation duly organized, existing, and operating under the laws of South Carolina. PSNC is engaged in the business of purchasing, transporting, distributing, and selling natural gas in North Carolina to approximately 550,000 residential, commercial, or industrial customers in its service territory. PSNC's service territory reaches all or parts of 28 franchised counties, including the Raleigh / Durham / Chapel Hill, Gastonia / Concord / Statesville, and Asheville / Hendersonville areas.

8. PSNC is a public utility under the laws of North Carolina and its public utility operations are subject to the jurisdiction of this Commission.

Procedural Status

9. The Applicants are lawfully and properly before this Commission pursuant to N.C. Gen. Stat. § 62-111(a) with respect to the relief sought in the Application and are in compliance with the requirements of the M-100, Sub 129 Order with respect to the filing of a market power analysis and a cost-benefit analysis related to the proposed transaction.

10. The Application, testimony, exhibits, affidavits of publication, and public notices submitted by the Applicants are in compliance with the procedural requirements of the North Carolina General Statutes and the Rules and Regulations of the Commission.

The Proposed Transaction

11. The Merger Agreement provides that, at closing, SCANA will merge with Sedona and SCANA will be the surviving corporation. Upon consummation of the Merger, each issued and outstanding share of common stock of SCANA (other than the cancelled shares as defined in Section 2.01(b) of the Merger Agreement) will be converted into the right to receive 0.6690 validly issued, fully paid and non-assessable shares of common stock of Dominion Energy. Upon consummation of the Merger, each issued and outstanding share of Sedona will be converted into and become one validly issued, fully paid, and non-assessable share of common stock of SCANA as the surviving corporation. Thus, as a result of the Merger, Dominion Energy will own all the stock of SCANA.

12. Following the closing of the Merger, Dominion Energy intends to add one member from SCANA's Board of Directors or SCANA's executive management team to the Dominion Energy Board of Directors.

13. Following the closing of the Merger, PSNC will remain a direct, wholly- owned subsidiary of SCANA and will continue to exist as a separate legal entity. Dominion Energy intends to manage PSNC from an operations standpoint as a separate regional business.

14. Following the closing of the Merger, Dominion Energy intends to maintain PSNC's headquarters in Gastonia, North Carolina, and to maintain compensation levels for PSNC employees until January 1, 2020.

The Stipulation

15. In summary, the Stipulation between the Applicants, the Public Staff, and Transco includes commitments by the Applicants to forego recovery of Merger-related expenses and hold DENC and PSNC customers[1] harmless from the impacts of debt downgrade; to create a regulatory liability of $3.75 million representing a refund to PSNC's customers of 2017 revenues over the course of three years; to increase PSNC's charitable contributions over its 2017 contributions by $150,000; to not file an application for a PSNC general rate case before April 1, 2021; to maintain current levels of PSNC's customer service and professional cooperation; to pursue cost savings opportunities between DENC and SCE&G; to provide for future filing and operation under new or amended affiliate agreements; and to comply with the Regulatory Conditions and Code of Conduct.

16. The Commission finds that the Stipulation is the product of give-and-take settlement negotiations among the parties and is material evidence entitled to be given appropriate weight by the Commission.

Benefits of the Merger

17. The Merger, as supplemented by the terms of the Stipulation, will result in quantifiable economic benefits for the customers of DENC and PSNC, as described in Findings of Fact Nos. 18 and 19 below.

18. The Stipulation requires PSNC to provide its North Carolina customers a total credit of $3.75 million through three direct bill credits of $1.25 million on January 1, 2019 (or as soon thereafter as practicable), January 1, 2020, and January 1, 2021.

19. The Stipulation requires that PSNC increase its charitable contributions over its 2017 contributions by $150,000, which shall be used to provide energy assistance for low-income customers in PSNC's service territory and shall be treated as below-the- line expenses for regulatory accounting, reporting, and ratemaking purposes.

[1] The Regulatory Conditions and Code of Conduct define the "customers" of DENC and PSNC as "retail electric customer of DENC in North Carolina and any Commission-regulated natural gas sales or natural gas transportation customer of PSNC located in North Carolina." In this Order, these customers are referred to as either "customers" or "retail customers."

20. The Merger will also result in non-quantifiable economic and non-economic benefits for the customers of DENC and PSNC. The non-quantifiable benefits are identified in the Cost-Benefit Analysis and testimony, as described in Findings of Fact Nos. 21-26 below.

21. The Cost-Benefit Analysis and testimony conclude that the Merger will increase PSNC's financial strength and reduce its market risk.

22. The Cost-Benefit Analysis and testimony conclude that PSNC will benefit from the shared services that will be available due to the Merger.

23. The Cost-Benefit Analysis and testimony conclude that PSNC will receive safety, reliability, environmental, and customer service benefits from the Merger.

24. The Cost-Benefit Analysis and testimony conclude that the proposed Merger will result in a more stable financial position for SCANA and PSNC.

25. The Cost-Benefit Analysis and testimony conclude that PSNC will benefit from lower corporate governance costs due to the Merger.

26. The Cost-Benefit Analysis and testimony conclude that PSNC will benefit from the maintenance of its employee compensation until January 1, 2020, and the retention of its headquarters and operations in Gastonia following the Merger.

Potential Costs

27. The Merger will result in known and potential costs. However, the known and potential costs of the Merger to North Carolina customers of DENC and PSNC are sufficiently mitigated by the Stipulation and the continued full regulatory authority of the Commission.

28. The Cost-Benefit Analysis identified transaction fees, integration costs, and an acquisition premium as transaction-related costs to be borne by Dominion Energy.

29. The Stipulation requires the Applicants to exclude from recovery from customers of DENC and PSNC the Merger-related expenses, which include acquisition premiums, change in control payments made to terminated executives, regulatory process costs, transactions costs, integration costs, and other transition costs.

30. The Stipulation also provides that PSNC will not file an application for a general rate case before April 1, 2021, and will not, except in certain circumstances, adjust its rates and charges or file for any cost deferral during or covering any period from the date of an order approving the Merger until after October 31, 2021.

Potential Risks

31. The Merger will result in potential risks. However, the potential risks of the Merger to North Carolina customers of DENC and PSNC are sufficiently mitigated by the Stipulation, the Regulatory Conditions, the Code of Conduct, and the continued full regulatory authority of the Commission.

ELECTRIC – MERGER

A. Potential Risks Addressed by the Stipulation

32. The Stipulation provides reasonable and adequate regulatory scrutiny over transactions involving DENC or PSNC with each other or with non-utility affiliates of Dominion Energy.

33. The Stipulation provides reasonable and adequate protections against the potential for discriminatory behavior in intra-company transactions by DENC and PSNC compared to their similar transactions with third parties.

34. The Stipulation precludes adverse impacts from the Merger on rates and services provided by DENC and PSNC.

B. Potential Risks Addressed by the Regulatory Conditions

35. The Regulatory Conditions included in the Stipulation are another benefit of the Merger to North Carolina retail customers in that they update, clarify, strengthen, and expand DENC's and PSNC's previous regulatory conditions.

36. The Regulatory Conditions effectively address potential risks and concerns related to financing issues arising from the Merger by ensuring that (a) DENC's and PSNC's capital structures and cost of capital are not adversely affected because of their affiliation with Dominion Energy, each other, and other affiliates, and (b) DENC and PSNC have sufficient access to equity and debt capital at reasonable costs to adequately fund and maintain their current and future capital needs and otherwise meet their service obligations to their retail customers.

37. The Regulatory Conditions effectively address potential risks and concerns related to corporate governance and ring-fencing issues arising from the Merger by ensuring the continued viability of DENC and PSNC and insulating and protecting DENC and PSNC and their retail customers from the business and financial risks of Dominion Energy and the affiliates within the Dominion Energy holding company system, including the protection of utility assets from the liabilities of affiliates.

38. The Regulatory Conditions effectively enable the Commission to exercise its jurisdiction over certain future business combinations involving Dominion Energy or other members of the Dominion Energy holding company family following the Merger by ensuring that the Commission receives sufficient notice and opportunity to exercise its lawful authority.

39. The Regulatory Conditions effectively address potential risks and concerns related to structure and organization arising from the Merger by ensuring that the Commission will receive adequate notice of, and opportunity to review and take such lawful action as is necessary and appropriate with respect to, changes to the structure and organization of Dominion Energy, DENC, PSNC, and other affiliates, and non-public utility operations as they may affect North Carolina retail ratepayers.

40. The Regulatory Conditions provide appropriate and effective procedures requiring advance notices and other filings arising from the Merger, and ensure monitoring of and compliance with their provisions, including the Code of Conduct, by requiring Dominion Energy, DENC,

PSNC, and other affiliates to establish and maintain the structures and processes necessary to fulfill the commitments expressed in the Regulatory Conditions and the Code of Conduct in a timely, consistent, and effective manner.

41. The Regulatory Conditions effectively ensure that DENC and PSNC maintain a strong commitment to customer service following the Merger.

42. The Regulatory Conditions effectively ensure that DENC's and PSNC's North Carolina retail customers are protected from any adverse effects of any tax sharing agreement and receive an appropriate portion of any income tax benefits associated with services taken by DENC and PSNC from an affiliated service company.

43. The Regulatory Conditions effectively protect the Commission's jurisdiction as a result of the Merger, including risks related to agreements and transactions between and among DENC, PSNC, and their affiliates; financing transactions involving Dominion Energy, DENC, PSNC, and any other affiliate; the ownership, use, and disposition of assets by DENC or PSNC; and filings with federal regulatory agencies. In addition, they protect DENC's and PSNC's retail ratepayers as much as reasonably possible from any adverse consequences potentially resulting from the Merger.

44. The Regulatory Conditions effectively address potential risks and concerns related to the possible adverse impact on the cost of capital of DENC and PSNC from Merger-related credit downgrades.

45. The Regulatory Conditions effectively ensure that DENC will continue to comply with the reporting requirements with regard to Dominion Energy's integration into PJM Interconnection, L.L.C. (PJM).

46. The Regulatory Conditions effectively protect DENC and PSNC customers by establishing a refund to customers by PSNC, establishing a rate moratorium for PSNC, requiring DENC and SCE&G to seek cost savings opportunities, and establishing a most favored nation obligation.

C. Potential Risks Addressed by the Code of Conduct

47. The Code of Conduct, as well as existing regulatory requirements, provides reasonable and adequate regulatory oversight of affiliate contracts and cost allocations.

48. The Code of Conduct provides reasonable and adequate regulatory oversight to ensure that the costs of common goods and services are fairly allocated among affiliates, to protect customers from overcharges by non-regulated affiliates, and to prevent cross-subsidization of non-regulated affiliates by DENC's and PSNC's customers.

49. The Code of Conduct provides reasonable and adequate regulatory oversight to ensure that costs incurred by DENC and PSNC are properly incurred, accounted for, and directly charged, assigned, or allocated to their respective North Carolina retail operations.

50. The Code of Conduct provides reasonable and adequate regulatory oversight by providing for appropriate and effective auditing and reporting requirements with respect to affiliate transactions and cost of service for retail ratemaking purposes.

51. The Code of Conduct provides reasonable and adequate regulatory oversight to ensure that DENC and PSNC continue to independently acquire and own their own upstream pipeline capacity and supply contracts based upon the needs of their respective customers.

Market Power Study

52. The proposed Merger will not lead to competitive concerns or an increased ability to exercise additional market power by Dominion Energy, DENC, or PSNC, will not result in an anti-competitive impact on markets subject to the Commission's jurisdiction, and will not create the potential for self-dealing between DENC and PSNC.

Approval of Stipulation

53. The Commission finds and concludes in light of the evidence presented that the Stipulation is just and reasonable to the customers of DENC and PSNC and to all parties to this proceeding, and that it serves the public interest. Therefore, the Stipulation should be approved in its entirety. In addition, it is entitled to substantial weight and consideration in the Commission's decision in this matter.

Public Convenience and Necessity

54. The proposed Merger, as modified, limited, and restricted by the Stipulation, including the Regulatory Conditions and Code of Conduct, is justified by the public convenience and necessity, serves the public interest, and should be approved pursuant to N.C. Gen. Stat. § 62-111.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-10

The evidence supporting these findings of fact is set forth in the Application, the Merger Agreement, the Market Power Analysis, the Cost-Benefit Analysis, the testimony of Applicants' witnesses Farrell, Addison and Chapman, and the Commission's records in this and other proceedings. These findings are essentially informational, procedural, and jurisdictional in nature and are not contested by any party.

According to the Application and Merger Agreement, as well as the testimony of witnesses Farrell, Addison, and Chapman, Dominion Energy and SCANA intend to engage in a merger transaction pursuant to which SCANA will become a wholly-owned subsidiary of Dominion Energy. Upon consummation of the Merger, each issued and outstanding share of common stock of SCANA will be converted into the right to receive 0.6690 validly issued, fully paid and non-assessable shares of common stock of Dominion Energy. Tr. pp. 29-30, 56. The transaction requires the approval of the Commission under N.C. Gen. Stat. § 62-111(a), and the Application seeks such approval.

In addition, the M-100, Sub 129 Order requires the Applicants to file both a market power analysis and a cost-benefit analysis in conjunction with an application for Commission approval of the proposed Merger. The market power analysis must include a Herfindahl-Hirschman Index (HHI) evaluation of the proposed Merger, and the cost- benefit analysis must set forth a "comprehensive list of all material areas of expected benefit, detriment, cost, and savings over a specified period (e.g., three to five years) following consummation of the merger. . . ." See M-100, Sub 129 Order, p. 7. The purpose of these required filings is to assist the Commission in making the public convenience and necessity determination required under N.C. Gen. Stat. § 62-111(a).

Consistent with the requirements of the M-100, Sub 129 Order, the Application included both a Cost-Benefit Analysis and a Market Power Analysis as Exhibits 4 and 5, respectively. The Market Power Analysis was prepared by Charles River Associates and contains, among other things, an HHI analysis of the relative market power of Dominion Energy both before and after the proposed Merger, as required by the M-100, Sub 129 Order. The Cost-Benefit Analysis enumerates identified costs and benefits associated with the proposed Merger. In its Scheduling Order, the Commission found and concluded that "the application satisfies the requirements of the November 2, 2000, Order in Docket No. M-100, Sub 129." Scheduling Order, p. 2. No party challenged Applicants' satisfaction of the M-100, Sub 129 Order requirements.

Finally, a review of the record in this proceeding indicates that the Applicants have complied with all procedural and notice requirements established by the Commission in the Scheduling Order.

The Commission, therefore, finds and concludes that Dominion Energy and SCANA are lawfully before the Commission with respect to the relief sought in the Application and are in compliance with the Merger filing requirements established in Docket No. M-100, Sub 129, with respect to the Market Power Study and Cost-Benefit Analysis submitted with the Application.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11-14

The evidence supporting these findings of fact is set forth in the Application, the Merger Agreement, and the testimony of Applicants' witnesses Farrell, Addison, Chapman, Wagstaff and Wohlfarth.

Through the Application and supporting testimony, the Applicants described the process for accomplishing the Merger, and the holding company structure that will exist upon closing.

The Application describes the proposed Merger transaction as follows:

(i) Sedona and SCANA will merge, with SCANA being the surviving entity;
(ii) Immediately following the time the Merger is effective, the officers of SCANA will be those persons that were the officers of SCANA immediately prior to the effective time of the Merger. Subsequent to the effective time of the Merger, changes to the officers of SCANA may be made based upon integration efforts and Dominion Energy's entity management conventions; and
(iii) SCANA will be a direct, wholly-owned subsidiary of Dominion Energy.

Application, Paragraph No 8.

The Application further indicates that

> upon consummation of the Merger, each issued and outstanding share of common stock of SCANA (other than the cancelled shares as defined in Section 2.01(b) of the Merger Agreement) will be converted into the right to receive 0.6690 validly issued, fully paid and non-assessable shares of common stock of Dominion Energy.

Id. Finally, the Application indicates that "[f]urther, upon consummation of the Merger, each issued and outstanding share of common stock of Sedona will be converted into and become one validly issued, fully paid, and non-assessable share of common stock of SCANA as the surviving corporation. Thus, as a result of the Merger, Dominion Energy (which currently owns all of the stock of Sedona) will own all the stock of SCANA." Id.

This structure is further confirmed by the provisions of the Merger Agreement, which is attached to the Application as Exhibit 1. This structure is also described in the testimony of Applicants' witnesses Farrell, Addison, and Chapman, and those descriptions are consistent with the Application and Merger Agreement.

The Application provides, in Paragraph No. 30(i), that "[t]he Transaction will not have a net adverse impact on the rates and services of Dominion Energy North Carolina or PSNC Energy."

The Merger Agreement provides, in Section 5.16(c), that Dominion Energy "will take all necessary action as soon as practicable after the Effective Time to appoint a mutually agreeable current member of the Company [SCANA] Board or the Company's executive management as a director to serve on Parent's board of directors." The Application provides that "Dominion Energy intends that its board of directors will take all necessary action, as soon as practical after the Effective Time, to appoint a mutually agreeable current member of the SCANA Board or SCANA's executive management team." Id. at Paragraph No. 29.i.b.

The Application provides, in Paragraph No. 24, that "[f]ollowing the Merger, Dominion Energy and SCANA plan to operate PSNC Energy in substantially the same manner as it is operated today .... Dominion Energy intends to maintain PSNC Energy's headquarters in Gastonia, North Carolina." Similarly, in Paragraph No. 29.i.a., the Application states that "Dominion Energy intends to maintain PSNC Energy's headquarters in Gastonia, North Carolina" In Paragraph No. 29.ii., the Application provides that "Dominion Energy will maintain compensation levels for employees of SCANA and its subsidiaries following the Effective Time of the Merger until January 1, 2020 ... Dominion Energy will give employees of SCANA and its subsidiaries due and fair consideration for other employment and promotion opportunities within the larger Dominion Energy organization to the extent any such employment positions are re-aligned, reduced, or eliminated in the future as a result of the Merger."

The Merger Agreement provides additional evidence on these matters. In Section 5.06(a), the Merger Agreement provides that from the Effective Time and until December 31, 2019, "Parent shall provide, or shall cause the Surviving Corporation to provide, the individuals who are employed by the Company or any of its Subsidiaries immediately before the Effective Time ...

(i) annual base compensation no less than the annual base compensation provided to such Company Non-Union Employees immediately prior to the Effective Time."

Applicants' witness Farrell testified that "Dominion Energy will maintain PSNC's corporate headquarters in Gastonia, North Carolina" and that "PSNC's generous historical charitable giving levels—all funded by shareholders—also will be increased." Tr. p. 24. Witness Farrell also explained that "[f]ollowing the combination, Dominion Energy plans to operate PSNC in substantially the same manner as it is operated today, enhanced by Dominion Energy's broad and deep experience in the successful management of natural gas systems." Tr. p. 21. Applicants' witness Wagstaff testified that "Dominion Energy has no current plans to change the organizational structure of PSNC operations as a result of the combination." Tr. p. 46. Witness Wagstaff also testified that "Dominion Energy will manage PSNC from an operations standpoint as a separate regional business under Dominion Energy." Tr. p. 47. Applicants' witness Wohlfarth also explained that PSNC will be managed "from an operations standpoint as a separate regional business with responsibility for making decisions that achieve" the Applicants' objectives. Tr. p. 99.

At the hearing, witness Wohlfarth clarified in response to Commissioners' questions that the management of PSNC as an independent regional entity would continue both during and subsequent to the initial post-Merger transition period. Tr. pp. 106-107.

Based on the foregoing evidence, the Commission finds and concludes that following the Merger PSNC will continue to be operated in substantially the same manner that it is operated today.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15-16

The evidence for these findings of fact is set forth in the Stipulation and the testimony of Applicants' witnesses Wohlfarth and Harris.

The Stipulation includes agreements among the Stipulating Parties on numerous subjects, revised Regulatory Conditions, and a revised Code of Conduct. The main provisions included in the Stipulation are: (i) creation of a regulatory liability of $3.75 million representing a refund to PSNC's North Carolina customers through three $1.25 million in bill credits in 2019, 2020, and 2021; (ii) in 2019, a commitment to increase PSNC's annual community support and charitable contribution initiatives by $150,000 more than its 2017 contributions; (iii) exclusion of Merger-related direct expenses, including acquisition premiums, integration costs, and severance payments, from recovery through customer rates; (iv) to not file an application for a PSNC general rate case before April 1, 2021; (v) customer protection from debt downgrade; (vi) maintenance of PSNC's current level of customer service; and (vii) a requirement to file any new or amended affiliate contracts for approval by the Commission.

Additionally, the Stipulating Parties agreed to a set of Regulatory Conditions and a Code of Conduct, appended as Attachment A to the Stipulation, which were revised by the Public Staff's filing on October 10, 2018. The Stipulating Parties stated that they used as a starting point the Regulatory Conditions and Code of Conduct that were approved by the Commission in the Order Approving Merger Subject to Regulatory Conditions and Code of Conduct issued

September 29, 2016, in Docket Nos. E-2, Sub 1095; E-7, Sub 1100; and G-9, Sub 682 (Duke-Piedmont Merger Order), and the Order Granting Motion to Amend Regulatory Conditions issued August 24, 2018, in Docket Nos. E-2, Sub 1095A; E-7, Sub 1100A; and G-9, Sub 682A (Duke-Piedmont Amended Conditions Order). The Stipulating Parties stated that the Regulatory Conditions and Code of Conductrepresent commitments by the Applicants as a precondition of approval of the Application and that the Regulatory Conditions would be incorporated into any order of the Commission approving the Merger. Stipulation, at Tr. pp. 1-2.

Paragraph No. 14 of the Stipulation states, in pertinent part, that the agreement "is the product of give-and-take negotiations."

In addition, the Stipulation is supported by the supplemental testimony of Applicants' witnesses Wohlfarth and Harris. Witness Wohlfarth's supplemental testimony described the discovery process with the Public Staff and the subsequent settlement negotiations among the Stipulating Parties that "involved substantial compromise by all parties on numerous issues." Tr. p. 91. Witness Wohlfarth explained that the Stipulation benefits customers in a number of ways, including rate stability associated with PSNC's commitment not to file a general rate case prior to April 1, 2021, and incorporation of the revised Code of Conduct and Regulatory Conditions that "put safeguards in place to ensure that customers will not be harmed by the Merger." Tr. pp. 97-98. Witness Wohlfarth also testified that the "Merger will have no adverse impact on the rates charged and the services provided by DENC and PSNC to North Carolina customers" and that "the benefits of the Merger to DENC's and PSNC's customers are sufficient to offset any potential costs and risks." Tr. pp. 99-100.

Witness Harris also testified about the benefits to customers as a result of the Merger, including a refund to PSNC customers as a bill credit of $1.25 million each January in 2019, 2020 and 2021. Tr. p. 83. Witness Harris further testified to the benefits of PSNC's rate moratorium as well as PSNC's increase in charitable contributions over its 2017 contribution level by $150,000. Tr. p. 83. Finally, Witness Harris stated that the Stipulation will "ensure that the Merger will have no adverse impact on the rates and the service provided by PSNC to North Carolina customers and that the benefits of the Merger to PSNC's customers are sufficient to offset any potential costs and risks." Tr. p. 84.

At the hearing, in response to questions by the Chairman, witness Wohlfarth testified to the back and forth nature of the negotiations that resulted in the Stipulation. He stated that even though the Stipulation may include provisions that, on an individual basis, the Applicants would prefer not be included, the Applicants are satisfied with the overall comprehensive settlement, given the "puts and takes of the many different provisions" of the Stipulation. Tr. pp. 118-119.

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

> [A] stipulation entered into by less than all of the parties as to any facts or issues in a contested case proceeding under Chapter 62 should be accorded full consideration

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

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

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

The Commission gives substantial weight to the testimony of the Applicants' witnesses regarding the Stipulation, and finds and concludes that the Stipulation is the product of the give-and-take of the settlement negotiations between the Applicants, the Public Staff and Transco in an effort to appropriately balance the Applicants' desire for approval of the Merger with the impact of the Merger on DENC's and PSNC's customers. Based on the foregoing and the record, the Commission finds and concludes that the Stipulation is the result of give-and-take negotiations, and is material evidence to be given appropriate weight in this proceeding.

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

The evidence for these findings of fact is set forth in the Application, the Cost-Benefit Analysis, the testimony of Applicants' witnesses, the testimony of the Public Staff Panel, and the Stipulation.

The Application recites several asserted benefits from the proposed Merger. These include: (i) financial benefits resulting from a larger more diversified company; (ii) direct and immediate operational benefits to customers; (iii) enhanced ability of Dominion Energy and SCANA to participate in the growing natural gas sector of the US economy; future integration benefits; (v) maintenance of a strong corporate presence in North Carolina; and (vi) maintenance of effective regulation by the Commission.

In the Cost-Benefit Analysis, Dominion Energy and SCANA also identified the benefits attendant to the proposed Merger, including: (i) increased financial strength and reduced market risk; (ii) shared services benefits; (iii) safety, reliability, environmental, and customer service benefits; (iv) removal of the current financial uncertainty of SCANA and a more stable financial position for SCANA and PSNC; (v) lowered corporate governance costs; (vi) increased corporate contributions; and (vii) maintenance of PSNC's Energy's corporate presence in North Carolina.

In addition, Applicants' witness Farrell testified to a number of benefits from the Merger. These ranged from growth of safe, reliable, and cost-effective service to continued Commission regulatory authority over both PSNC and DENC to ensure protection of North Carolina customers. Tr. pp. 21-23.

Applicants' witnesses Addison and Harris testified regarding benefits to PSNC and its customers arising from the proposed Merger. These include access to greater financial resources along with more geographic and business diversity. Tr. pp. 34, 78. According to witness Addison, the Merger will also offer greater economies of scale in providing or acquiring services to support the SCANA companies, such as PSNC, and their customers. Tr. p. 34.

Witness Harris testified that the Merger will enhance PSNC's ability to continue providing safe, reliable, and cost-effective operations across a growing customer base due to greater access to equity capital. Witness Harris also noted that the Mergershould positively affect PSNC's credit rating. Tr. pp. 78-79. Witness Harris testified to his belief that the Merger will be seamless to customers as a result of Dominion Energy's express intent to operate PSNC in substantially the same way as it is operated today. Tr. p. 79. He stated that the integration of the companies should result in operational cost savings going forward and enhanced service quality through the sharing of best practices between DENC and PSNC. Tr. p. 78. Witness Harris also co-sponsored the Cost-Benefit Analysis attached to the Application, which described the benefits that will be realized by the companies and their respective customers. Tr. p. 75.

Applicants' witness Chapman testified that the proposed Merger would benefit the companies and their customers. Witness Chapman specifically identified the following discrete benefits from the transaction: (i) PSNC will benefit from being part of a large corporate organization with enhanced geographic, business, and regulatory diversity and a greater financial and operational scale; (ii) Dominion Energy will provide equity, as needed, to PSNC to maintain PSNC's current capital structure and improve credit ratings; (iii) access to an array of services, support, and economies of scale; and (iv) stabilization of the companies' long-term growth objectives. Tr. p. 61.

Applicants' witness Wagstaff also testified that the proposed Merger would have operational and financial benefits that would ultimately benefit DENC and PSNC customers. Specifically, witness Wagstaff testified that Dominion Energy will: (i) maintain PSNC's current customer service levels; (ii) not diminish PSNC's focus on installing, upgrading, and maintaining facilities for safe and reliable operations; (iii) maintain the pipeline integrity program at or above PSNC's current levels; and (iv) increase SCANA's historical level of corporate contributions. Tr. pp. 47-48. Witness Wagstaff also indicated that PSNC will benefit from being part of a corporate organization with enhanced geographic, business, and regulatory diversity, as well as greater financial and operational scale. Tr. p. 49.

The Public Staff Panel also testified to the benefits and protections of the Merger for North Carolina customers. These benefits and protections include: (i) preventing Merger-related direct expenses from being passed on to customers; (ii) Merger-related cost savings guaranteed through the Stipulation; (iii) provisions regarding the replacement cost rate for debt; and (iv) creating a financially stronger company allowing PSNC greater access to capital markets. Tr. pp. 148-51, 161. The Public Staff Panel expressed concern that Dominion Energy and SCANA had not quantified economic benefits to customers, noting the Applicants' explanation that quantification was not possible at this time. The Public Staff recommended several conditions be imposed on approval of the Merger due to the lack of quantified benefits, including: (1) a bill credit to PSNC customers totaling $3.75 million over 3 years; (2) to not file an application for a PSNC general rate case before April 1, 2021, and will not increase its non-gas cost margin in its rates until November 1, 2021; (3) holding DENC and PSNC customers harmless from the impacts of debt downgrades for a period of five years; (4) requiring PSNC to maintain current levels of customer service and behavior towards customers and professional cooperation with regulators, consumer advocates, and intervenors; (5) post- merger opportunities for the electric utility operations of DENC and SCE&G; and (6) other benefits to customers such as the most favored nation clause that is intended to ensure that North Carolina retail customers receive the benefit of a "Most favored Nation" status with regard to the provision of Merger benefits and protections among the states involved in this proceeding. Ultimately, however, the Public Staff Panel recommended that the Merger be approved. Tr. pp. 150-67.

As discussed above, in the Stipulation the Stipulating Parties agreed to a number of benefits to be provided to customers of DENC and PSNC upon closing of the Merger. Paragraph No. 10 of the Stipulation concludes that these terms will assure that the proposed Merger is justified by the public convenience and necessity and meets the standard for approval by the Commission under N.C. Gen. Stat. § 62-111(a).

This conclusion is echoed in the supplemental testimony of Applicants' witnesses Wohlfarth and Harris. As noted above, Applicants' witnesses Wohlfarth and Harris testified that the Stipulation was the result of "substantial compromise by all parties" and provided numerous benefits to customers.

The Commission has carefully reviewed and considered all of the evidence set forth above describing the known and potential benefits of the proposed Merger, finds it to be credible, and gives it substantial weight. Many of these benefits have been enhanced and guaranteed as a result of the Stipulation filed in this proceeding. Based upon that evidence, and the lack of any significant countervailing evidence, the Commission finds and concludes that there are substantial quantifiable and non- quantifiable benefits to be derived from the Merger by the customers of DENC and PSNC.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 27-29

The evidence supporting these findings of fact is set forth in the Application, the Cost-Benefit Analysis, the testimony of Applicants' witnesses, the testimony of the Public Staff Panel, and the Stipulation.

In the Application, the Applicants stated that the Merger will not have a net adverse impact on the rates and services of DENC or PSNC and that, although the Applicants had not yet determined the transaction fees, integration costs, and any acquisition premium that will result from the

Merger, none of those costs will be passed on to DENC or PSNC customers. Application, Paragraph No. 30(i).

The Cost-Benefit Analysis identified transaction fees, integration costs, and acquisition premium over book value as potential costs of the Merger, but concluded that while Applicants had not yet determined the amount of such costs, none of these costs will be passed on to DENC or PSNC customers. Cost-Benefit Analysis, at p. 6. The Cost- Benefit Analysis concluded that the Merger provides only benefits, and no detriment to the State of North Carolina and to PSNC, and that all transaction fees and integration costs and any acquisition premium that will result from the Merger would not be passed on to PSNC's or DENC's customers. Cost-Benefit Analysis, at p. 1.

Applicants' witness Farrell testified that the Merger of SCANA and Dominion Energy will not have a net adverse impact on DENC's or PSNC's rates or services. He explained that no transaction fees, integration costs, or any acquisition premium resulting from the Merger would be passed on to DENC or PSNC customers. Tr. p. 22. Similarly, Applicants' witness Chapman testified that PSNC and DENC will not seek recovery of any acquisition premium costs, transition costs, or transaction costs associated with the Merger from their customers. Tr. p. 61.

The Public Staff Panel recognized the Applicants' commitment that no change in control payments or severance payments, transaction fees, integration costs, or acquisition premium will be passed on to customers. The panel testified that based on its review of SCANA's Proxy Statement dated June 15, 2018, SCANA's estimated transaction costs are $59 million. The panel also testified to Applicants' estimate of the incremental change in control payments to SCANA executives provided through discovery, and that, based on SCANA's book value as of December 31, 2017, the Merger would result in an estimated $839 million acquisition premium, which would be recorded at the Dominion Energy holding company level and would not impact DENC's or PSNC's financial statements. The Public Staff recommended that DENC and PSNC file a summary report of their final accounting for Merger-related direct expenses and the acquisition premium within 60 days of the Merger as well as supplemental reports as necessary. Tr. pp. 146-49.

As noted above, the Stipulation provides that the Applicants will forego recovery of Merger-related direct expenses.

The Commission finds and concludes that the evidence demonstrates that customers will not pay for Merger-related direct expenses associated with the Merger. First, the Application and the Cost-Benefit Analysis commit the Applicants not to seek recovery of several categories of Merger-related costs of which they would otherwise be entitled to seek recovery. Specifically, the Applicants have expressly waived, in both the Application and the Cost-Benefit Analysis, any right to seek recovery of any acquisition premium associated with the Merger as well as any transaction fees or integration costs (including severance payments) associated with the Merger. Given the estimated transaction costs of $59 million, the estimated integration costs, and the acquisition premium, the latter of which was estimated at $839 million, this waiver is a significant commitment, and serves to insulate customers from the costs of the Merger transaction itself as well as other Merger-related expenses. In addition, based on the Stipulation, Applicants have precluded the possibility that they may seek recovery of any Merger- related costs from customers for Commission financial reporting and ratemaking purposes. As defined in Paragraph No. 4 of the Stipulation, these Merger-related expenses include acquisition premiums, change in control payments, regulatory process costs, and transaction costs, such as investment banking, legal, accounting, securities issuances, and advisory fees. Paragraph No. 4 defines integration costs to include the integration of financial, IT, human resources, billing, accounting, and telecommunications systems. This provision further states that "other transition costs" include severance payments, changes to signage, the cost of transitioning employees to post-Merger employee benefits plans, and costs to terminate any duplicative leases, contracts and operations. This provision provides significant additional protection for DENC and PSNC customers from the costs and quantifiable risks associated with the Merger.

The Commission has carefully reviewed and considered all of the evidence set forth above describing the potential costs and the known and potential benefits of the proposed Merger, finds it to be credible, and gives it substantial weight. Further, the Commission finds and concludes that the commitments in the Stipulation are significant and effectively mitigate the potential direct costs of the Merger to customers.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 30-34

The evidence supporting these findings of fact is set forth in the Public Staff Panel testimony, the Transco testimony, the Stipulation, Applicants' supplemental testimony, and the Commission's statutory and inherent supervisory authority.

The Public Staff Panel testified in support of a number of conditions to the Merger that it believed were necessary to address risks that the Public Staff identified in association with the Merger. With regard to its recommendation for a rate moratorium until November 1, 2021, the Public Staff clarified that, because the Commission found in its order in Docket No. G-5, Sub 565, that the proposed integrity management tracker (IMT) expressly provides for Commission review of the mechanism at the earlier of PSNC's next general rate case proceeding or four years from the implementation of the mechanism, the Public Staff believes that the IMT can still continue without PSNC having to file a general rate case. Tr. p. 156. With respect to the effect of the Merger on the PJM regulatory conditions imposed by the Commission on DENC in Docket No. E-22, Sub 532, the Public Staff testified that based on Section VI of the revised Regulatory Conditions, all of the PJM conditions imposed by the Commission in the Sub 532 case will remain in effect. Tr. p. 164. Finally, the Public Staff testified in support of a most favored nation clause. Tr. pp. 166-67.

Transco witness Amezquita testified to concerns about the impact of the proposed Merger, including that Transco's natural gas capacity may not be utilized as much as a result of the Merger, which could cause price increases for North Carolina customers. Tr. p. 131. Witness Amezquita provided several recommendations to the Commission to avoid these potential impacts, including a requirement for PSNC to engage in good faith negotiations with third party natural gas capacity suppliers, with Commission oversight. Tr. pp. 134-35. Subsequent to filing witness Amezquita's testimony, Transco joined the Stipulation as a Stipulating Party.

As discussed above, the provisions of the Stipulation protect customers from adverse impacts to rates and services, prohibit unfair dealing through affiliate agreement provisions, and commit DENC and PSNC to the Regulatory Conditions and Code of Conduct. Additionally, Applicants' witnesses Wohlfarth and Harris testified in support of these provisions of the Stipulation in their supplemental testimonies and identified the benefits and financial protections that PSNC customers will receive as a result of the Stipulation.

At the hearing, Applicants' witness Harris and Public Staff witness Larsen confirmed in response to questions by the Commission that the IMT could continue without PSNC filing a general rate case before April 1, 2021, as provided in the Stipulation. Tr. pp. 111, 183.

Under N.C. Gen. Stat. § 62-30, the Commission has general power and authority to supervise and control public utilities. Further, N.C. Gen. Stat. § 62-32 grants the Commission supervisory power over public utility rates and service, including the power to compel reasonable service and set reasonable rates. As noted above, Paragraph No. 29 of the Application provides that, after the Merger, the "Commission will continue to exercise its regulatory authority over [PSNC] and [DENC] in the same way it does today, thereby ensuring continued protection of the interests of North Carolina customers."This continuing and undiminished regulatory oversight will serve to protect customers from adverse consequences of the Merger.

Separate and apart from the Commission's inherent and continuing supervisory function, there is substantial evidence in this proceeding that customers are and will be protected from potential costs and risks of the Merger. In addition to the protections against the costs of the Merger discussed above, the Stipulation provides that PSNC and DENC customers will be held harmless from the impacts of a debt downgrade, requires that PSNC maintain current levels of customer service and behavior toward customers and current levels of professional cooperation, imposes additional obligations on the Applicants with respect to affiliate agreements, and commits the Applicants to abide by the Regulatory Conditions and Code of Conduct. Based on the evidence presented, the Commission concludes that the Stipulation provides reasonable and adequate regulatory scrutiny over transactions involving DENC or PSNC with each other, or with non-utility affiliates of Dominion Energy. Further, the Commission concludes that the Stipulation provides reasonable and adequate protections against the potential for discriminatory behavior in intra-company transactions by DENC and PSNC compared to their similar transactions with third parties, through the Applicants' commitment to the Regulatory Conditions and Code of Conduct, and through the requirements in Paragraph No. 9 of the Stipulation pertaining to affiliate agreements. In addition, the Commission concludes that the Stipulation resolves Transco's concerns regarding the Merger.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 35-46

The evidence supporting these findings of fact is set forth in the Stipulation, including the proposed Regulatory Conditions and Code of Conduct, the testimony of the Public Staff Panel, the testimony of Applicants' witnesses Wohlfarth and Harris, and the Commission's statutory and inherent supervisory authority.

In addition to the protection against risks of the Merger provided by the Stipulation itself, the proposed Regulatory Conditions and Code of Conduct also safeguard customers from potential adverse impacts on rates and services as a result of the Merger. As noted above, the proposed Regulatory Conditions and Code of Conduct would update the regulatory conditions and codes of conduct currently in effect for DENC and PSNC, and are largely based on the Regulatory Conditions and Code of Conduct that were approved by the Commission in the Duke-Piedmont Merger Order and the Duke- Piedmont Amended Conditions Order.

The Regulatory Conditions provide numerous protections and restrictions governing the ongoing operations of DENC and PSNC. These safeguards include a number of provisions designed to (i) preserve the Commission's jurisdiction over the regulated utilities (Regulatory Conditions, Section III); (ii) establish intra-company financing requirements and separate accounting for each utility (Regulatory Conditions, Sections VII and VIII); (iii) ensure ongoing review of the operations of DENC and PSNC under a holding company structure (Regulatory Conditions, Section VIII); (iv) provide the Commission with advance notice of proposed business combinations and mergers, and advance notice of changes in the structure and organization of Dominion Energy, DENC, and PSNC (Regulatory Conditions, Section IX and X); (v) ensure continuing levels of service quality for the respective customers of DENC and PSNC (Regulatory Conditions, Section XI); (vi) ensure that DENC's and PSNC's North Carolina retail customers do not bear any additional tax costs as a result of the Merger and that they receive an appropriate share of any tax benefits associated with the service company affiliates (Regulatory Conditions, Section XII); (vii) ensure that Dominion Energy, DENC, PSNC, and all other affiliates establish and maintain the structures and processes necessary to fulfill the commitments expressed in the Regulatory Conditions and the Code of Conduct in a timely, consistent, and effective manner (Regulatory Conditions, Section XIV); (viii) preserve the integrity of utility-specific acquisitions of upstream supply and capacity (Regulatory Conditions, Section XV); and (ix) ensure through rate and other protections for PSNC's North Carolina retail customers that the benefits of the Merger are equal to or surpass the costs of the Merger to those customers (Regulatory Conditions, Section XVI).

The purpose of Section III of the Regulatory Conditions is to protect the Commission's jurisdiction as a result of the Merger, including risks related to agreements and transactions between and among DENC, PSNC, and any of their affiliates, financing transactions involving Dominion Energy, DENC or PSNC, and any other affiliate, and the ownership, use, and disposition of assets by DENC or PSNC. This section includes Regulatory Condition No. 3.1, which requires DENC and PSNC to submit proposed affiliate agreements to the Public Staff for informal review at least 15 days before filing with the Commission so that a determination can be made as to whether the agreements require Commission action. This condition also requires that, for any contract that must be filed with the Federal Energy Regulatory Commission (FERC), DENC and PSNC will file for informational purposes a copy of the proposed agreement with the Commission at least 15 days prior to filing the agreement with FERC.

Regulatory Condition No. 3.2 states that contracts memorializing financing transactions between DENC and PSNC and their affiliates, or between affiliates that are reasonably likely to affect DENC's or PSNC's rates or service, must provide that DENC or PSNC shall not include the effects of any capital structure or debt or equity costs associated with the transactions in its North Carolina retail cost of service or rates, except as allowed by the Commission.

Regulatory Condition No. 3.3 stipulates that DENC and PSNC will own and control the assets used to serve their respective retail customers. Further, if DENC or PSNC intends to transfer an asset having a net book value in excess of $10 million, they are required to provide the

Commission with at least 30 days advance notice of the proposed transfer and cannot include the value of the transfer in rates without Commission approval.

Regulatory Condition No. 3.8 also includes provisions intended to protect the Commission's jurisdiction. Regulatory Condition No. 3.8(f) as proposed in the October 10, 2018, filing by the Public Staff, provides that DENC, PSNC, Dominion Energy, other affiliates and the nonpublic utility operations shall (a) acknowledge the risk of any possible preemptive effects of federal law with respect to any contract, transaction, or commitment entered into or proposed by DENC or PSNC or that could affect DENC's or PSNC's operations, service, or rates and (b) take all actions as may be reasonably necessary and appropriate to hold North Carolina ratepayers harmless from rate increases, foregone opportunities for rate decreases, or other adverse effects of the preemption. At the hearing, the Chairman questioned how the Applicants interpreted this condition, and whether it could be interpreted to mean that, in circumstances where the Commission did not agree that costs incurred pursuant to federally approved rates should be passed to North Carolina customers, the utility's shareholders should bear that cost. Applicants' witness Wohlfarth testified that, while this condition could in the future be subject to interpretation, the Applicants remain obligated to act prudently regardless of any approved federal rate, and the Commission maintains its authority to make such prudence determinations. Tr. pp. 114-20. Public Staff witness Maness testified in response to similar questions by the Chairman that the key language in this condition is the requirement to take all actions as may be reasonably necessary and appropriate to hold North Carolina customers harmless. Witness Maness testified that the Public Staff determined that inclusion of this condition was reasonable because it was included in the regulatory conditions approved in the Duke-Piedmont Amended Conditions Order. Tr. pp. 179-81.

On October 31, 2018, the Public Staff and Applicants filed their Joint Proposed Order, which revised Regulatory Condition No. 3.8(f) to address the Chairman's concerns. The revised condition modifies subsection (B) of Regulatory Condition No. 3.8(f) to provide that DENC, PSNC, Dominion Energy, and any other Affiliates and the Nonpublic Utility Operations "shall take all actions as may be reasonably *and lawfully* necessary and appropriate to *advance the interests of* North Carolina ratepayers to avoid rate increases, foregone opportunities for rate decreases or any other adverse effects of such preemption *including but not limited to intervention in FERC proceedings on behalf of the interests of North Carolina ratepayers*." (Revisions in italics.)

Based on this evidence, the Commission finds and concludes that the Regulatory Conditions, including revised Regulatory Condition No. 3.8(f) as revised in the Joint Proposed Order filed on October 31, 2018, effectively address the concerns related to potential loss of or reduction in the Commission's jurisdiction arising from the Merger.

Section IV of the Regulatory Conditions is intended to ensure that the costs incurred by DENC and PSNC are properly incurred, accounted for, and directly charged, assigned, or allocated to their respective North Carolina retail operations, and that only costs that produce benefits to DENC's and PSNC's retail customers are included in their North Carolina cost of service for ratemaking purposes. The Commission finds and concludes that the Regulatory Conditions effectively address concerns related to the incurrence of, accounting for, and charging of costs to DENC's and PSNC's respective retail operations.

Section VI of the Regulatory Conditions incorporates the remaining conditions of Dominion Energy's integration into PJM, which are primarily reporting requirements. The Commission finds that these conditions will continue to apply to DENC and serve their intended purpose under these Regulatory Conditions.

The purposes of Section VII of the Regulatory Conditions are to ensure that (a) DENC's and PSNC's capital structures and cost of capital are not adversely affected through their affiliation with Dominion Energy, each other, and other affiliates, and (b) that DENC and PSNC have sufficient access to equity and debt capital at reasonable costs so as to adequately fund and maintain their current and future capital needs and otherwise meet their service obligations to their customers.

The Commission finds and concludes that the Regulatory Conditions effectively address the concerns related to potential financing issues arising from the Merger. In particular, the Commission finds and concludes that the Regulatory Conditions effectively protect DENC's and PSNC's capital structures and cost of capital from adverse consequences that might result from their affiliation with Dominion Energy, each other, and other affiliates, and ensure that DENC and PSNC have 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.

Section VIII of the Regulatory Conditions addresses the risks and concerns related to corporate governance and ring-fencing issues arising from the Merger. These Regulatory Conditions are intended to ensure the continued viability of DENC and PSNC and to insulate and protect DENC and PSNC and their North Carolina retail customers from the business and financial risks of Dominion Energy and the affiliates within the Dominion Energy holding company system, including the protection of utility assets from liabilities of affiliates.

For example, Regulatory Condition No. 8.1 requires DENC and PSNC to manage their respective businesses so as to maintain an investment grade debt rating on all of their rated debt issuances with all of the debt rating agencies. If the debt rating of either DENC or PSNC falls to within one notch of an investment grade rating by S&P and Moody's, a written notice by DENC or PSNC must be filed with the Commission and provided to the Public Staff within five days, along with an explanation as to why the downgrade occurred. Furthermore, within 45 days of such notice, DENC or PSNC are required to provide the Commission and the Public Staff with a specific plan for maintaining and improving its debt rating. The Commission, after notice and hearing, may then take whatever action it deems necessary, consistent with North Carolina law, to protect the interests of DENC's or PSNC's North Carolina retail customers in the continuation of adequate and reliable service at just and reasonable rates.

In addition, Regulatory Condition No. 8.2 holds DENC's and PSNC's customers harmless against any potential increase in costs associated with a debt downgrade attributable to the Merger. The condition provides that if a downgrade occurs and is continuing, a replacement cost calculation will be determined, as part of DENC's and PSNC's future general rate cases, and the procedure shall be effective for five years following the Merger.

Another example of the financial integrity protections provided by the Regulatory Conditions is Regulatory Condition No. 8.3, which limits DENC's and PSNC's cumulative distributions paid to Dominion Energy subsequent to the Merger to (a) the amount of retained earnings on the day prior to the closure of the Merger, plus (b) any future earnings recorded by DENC and PSNC subsequent to the Merger.

The Commission finds and concludes that the Regulatory Conditions effectively address potential risks and concerns related to corporate governance and ring-fencing issues arising from the Merger by ensuring the continued viability of DENC and PSNC, and insulating and protecting DENC and PSNC and their retail customers from the business and financial risks of Dominion Energy and the affiliates within the Dominion Energy holding company system, including the protection of utility assets from the liabilities of affiliates.

The purpose of Section IX of the Regulatory Conditions is to ensure that the Commission receives sufficient notice to exercise its lawful authority over proposed mergers, acquisitions, and other business combinations involving Dominion Energy, DENC, PSNC, other affiliates, or non-public utility operations. Regulatory Condition No. 9.1 requires that advance notification be filed with the Commission at least 180 days prior to the proposed closing date for a proposed merger, acquisition, or other business combination that would affect DENC's or PSNC's rates or service. Regulatory Condition No. 9.2 requires that advance notification be filed with the Commission at least 90 days prior to the proposed closing date for the proposed merger, acquisition, or other business combination that is believed not to have an effect on DENC's or PSNC's rates or service, but that involves Dominion Energy, other affiliates, or non-public utility operations and that has a transaction value exceeding $1.5 billion. Any interested party may file comments within 45 days of the filing of the advance notification, and, if timely comments are filed, the Public Staff is required to place the matter on a Commission Staff Conference agenda and recommend how the Commission should proceed. This condition further provides that if the Commission determines that the merger, acquisition, or other business combination requires approval, an order shall be issued requiring the filing of an application, and no closing can occur until and unless the Commission approves the proposed merger, acquisition, or business combination.

The Commission finds and concludes that the Regulatory Conditions will effectively enable the Commission to exercise its jurisdiction over business combinations involving Dominion Energy or other members of the Dominion Energy holding company structure following the Merger by ensuring that the Commission receives sufficient notice to exercise its lawful authority over proposed mergers, acquisitions, and other business combinations involving Dominion Energy, DENC, PSNC, other affiliates, or the nonpublic utility operations of DENC and PSNC.

The Regulatory Conditions in Section X are intended to ensure that the Commission receives adequate notice of, and opportunity to review and take such lawful action as is necessary and appropriate with respect to, changes to the structure and organization of Dominion Energy, DENC, PSNC, and other affiliates, and nonpublic utility operations of DENC and PSNC as they may affect North Carolina retail customers.

Regulatory Condition No. 10.1 provides that DENC and PSNC are required to file notice with the Commission 30 days prior to the initial transfer or any subsequent transfer of any services, functions, departments, employees, rights, obligations, assets, or liabilities from DENC or PSNC to Dominion Energy's Service Company that (a) involves services, functions, departments, employees, rights, obligations, assets, or liabilities other than those of a governance or corporate nature that traditionally have been provided by a service company, or (b) potentially would have a significant effect on DENC's or PSNC's public utility operations.

Regulatory Condition No. 10.2 provides that, upon request, DENC and PSNC shall meet and consult with, and provide requested relevant data to the Public Staff regarding plans for significant changes in DENC's, PSNC's, or Dominion Energy's organization, structure (including RTO developments), and activities; the expected or potential impact of such changes on DENC's or PSNC's retail rates, operations, and service; and proposals for assuring that such plans do not adversely affect DENC's or PSNC's retail customers. To the extent that proposed significant changes are planned for the organization, structure, or activities of an affiliate or nonpublic utility operation and such proposed changes are likely to have an adverse impact on DENC's or PSNC's retail customers, then DENC's and PSNC's plans and proposals for assuring that those plans do not adversely affect those customers must be included in these meetings. DENC and PSNC shall inform the Public Staff promptly of any such events and changes.

The Commission finds and concludes that the Regulatory Conditions effectively address risks and concerns related to structure and organization arising from the Merger by ensuring that the Commission and the Public Staff will receive adequate notice of, and an opportunity to review and take such lawful action as is necessary and appropriate with respect to, changes to the structure and organization of Dominion Energy, DENC, PSNC, and other affiliates, and nonpublic utility operations of DENC and PSNC as they may affect North Carolina retail customers.

The Applicants state in the application that the proposed Merger in no way diminishes the Commission's authority to regulate the service quality of PSNC. Application, Paragraph No. 33. Section XI of the Regulatory Conditions contains twelve separate provisions that are intended to ensure that DENC and PSNC continue to implement and further their commitment to providing superior utility service by meeting recognized service quality indices and implementing the best practices of each other and their utility affiliates to the extent reasonably practicable. These provisions include overall service quality, best practices, right-of-way maintenance expenditures and clearance practices, customer access to service representatives and other services, call center operations, customer surveys, and regular meetings with the Public Staff on matters related to service quality. With respect to DENC, Regulatory Condition No. 11.2 also requires that DENC continue to take all reasonable and prudent actions necessary to continue to provide its North Carolina retail customers with superior bundled retail electric service.

In addition, Applicants' witness Farrell testified that Dominion Energy's "proven leadership team is unfailingly committed to the safe, reliable, cost-effective, and environmentally responsible provision of utility services to its customers" and "[t]hat commitment will apply equally to its operation of PSNC." Tr. p. 22.

The Commission finds and concludes that the Commission's continuing regulatory authority and procedures and the Regulatory Conditions will effectively ensure that DENC and PSNC maintain a strong commitment to customer service after the Merger.

Section XII of the Regulatory Conditions is intended to ensure that DENC's and PSNC's North Carolina retail customers do not bear any additional tax costs as a result of the Merger and that they receive an appropriate share of any tax benefits associated with the service company affiliates.

Regulatory Condition No. 12.1 provides that under any tax sharing agreement DENC and PSNC will not seek to recover from their North Carolina retail customers any tax cost that exceeds DENC's or PSNC's tax liability calculated as if DENC and PSNC were stand-alone taxable entities for tax purposes.

Regulatory Condition No. 12.2 provides that the appropriate portion of any income tax benefits associated with the Service Company will accrue to the North Carolina retail operations of DENC and PSNC for regulatory accounting, reporting, and ratemaking purposes.

The Commission finds and concludes that Regulatory Condition Nos. 12.1 and will effectively ensure that DENC's and PSNC's North Carolina retail customers (a) are protected from any adverse effects of a tax sharing agreement, and (b) will receive an appropriate portion of income tax benefits associated with the Service Company.

Section XIII of the Regulatory Conditions provides procedures for the implementation of conditions requiring advance notices and other filings arising from the Merger. The Commission finds and concludes that Section XIII of the Regulatory Conditions provides appropriate and effective procedures for the implementation of conditions requiring advance notices and other filings arising from the Merger.

Sections V and XIV of the Regulatory Conditions address compliance with the Code of Conduct. Section V obligates DENC, PSNC, Dominion Energy, and other affiliates to comply with the terms of the Code of Conduct. The purpose of Section XIV of the Regulatory Conditions is to ensure that Dominion Energy, DENC, PSNC, and all other affiliates establish and maintain the structures and processes necessary to fulfill the commitments expressed in the Regulatory Conditions and the Code of Conduct in a timely, consistent, and effective manner.

Regulatory Condition No. 14.1 requires Dominion Energy, DENC, PSNC, and all other affiliates to devote sufficient resources to the creation, monitoring, and ongoing improvement of effective internal compliance programs to ensure compliance with the Regulatory Conditions and the Code of Conduct. It further requires them to take a proactive approach toward correcting any violations and reporting them to the Commission, including the implementation of systems and protocols for monitoring, identifying, and correcting possible violations, a management culture that encourages compliance among all personnel, and the tools and training sufficient to enable employees to comply with Commission requirements.

Regulatory Condition No. 14.2 requires DENC and PSNC to designate a chief compliance officer who will be responsible for compliance with the Regulatory Conditions and Code of Conduct. This person's name and contact information must be posted on DENC's and PSNC's Internet Websites. Regulatory Condition No. 14.3 requires that annual training be provided by DENC and PSNC on the requirements and standards contained within the Regulatory Conditions and Code of Conduct to all of their employees, including Service Company employees, whose duties in any way may be affected by such requirements and standards.

Regulatory Condition No. 14.4 states that if DENC or PSNC discover that a violation of the requirements or standards contained within the Regulatory Conditions and Code of Conduct has occurred, then they are required to file a statement with the Commission describing the circumstances leading to that violation and the mitigating and other steps taken to address the current or any future potential violation.

The Commission finds and concludes that the Regulatory Conditions will effectively ensure monitoring and compliance with the Regulatory Conditions and the Code of Conduct by requiring Dominion Energy, DENC, PSNC, and all other affiliates to establish and maintain the structures and processes necessary to fulfill the commitments expressed in the Regulatory Conditions and the Code of Conduct in a timely, consistent, and effective manner. The purpose of Regulatory Condition XV is to preserve the integrity of utility specific acquisitions of upstream supply and capacity. Regulatory Condition No. 15.1 requires DENC and PSNC to determine the appropriate sources for their interstate pipeline capacity and supply on the basis of the benefits and costs to their respective customers. It also prohibits PSNC from contracting with an affiliate interstate pipeline for additional capacity with a contractual term of ten years or more without issuing a request for proposals, requires PSNC to consider the proposals in good faith, and prohibits PSNC from contracting with an affiliate unless the affiliate is the least cost provider or unless otherwise approved by the Commission. This regulatory condition addresses the concerns expressed by Transco witness Amezquita. Regulatory Condition No. 15.2 specifies that, except as provided in Code of Conduct Section III.D.5 (Joint purchases), PSNC shall retain title, ownership, and management of all gas contracts necessary to ensure the provision of reliable service to PSNC's customers consistent with its best cost gas and capacity procurement methodology.

The Commission finds and concludes that these Regulatory Conditions will effectively ensure the continuation of DENC's and PSNC's current practices for determining their long-term sources of interstate pipeline capacity and supply.

The purpose of Regulatory Condition XVI is to ensure, through rate and other protections for DENC's and PSNC's North Carolina retail customers that the benefits of the Merger are equal to or surpass the costs of the Merger to those customers. Regulatory Condition No. 16.1 echoes the commitment contained in the Stipulation that PSNC will create a regulatory liability of $3.75 million representing a refund to customers of 2017 revenues to be provided as bill credits of $1.25 million on January 1 of 2019 (or as soon thereafter those dates as practicable), January 1, 2020, and January 1, 2021. In addition, Regulatory Condition No. 16.2 states that PSNC will not file an application for a general rate case proceeding to adjust its rates and charges before April 20, 2021, and that, except in certain specified circumstances, PSNC will not file for any cost deferral during or covering any period from the date of an order approving the Merger until after October 31, 2021.

Regulatory Condition No. 16.3 states PSNC's agreement to maintain current levels of customer service and behavior towards customers, and of professional cooperation. Regulatory Condition No. 16.4 provides that the electric utility operations of DENC and SCE&G, along with their affiliates and subsidiaries, will look for post-Merger opportunities to engage in joint planning, purchasing, and services that will result in cost savings to DENC's customers while not compromising reliability or service quality. Finally, Regulatory Condition 16.5 is intended to ensure that DENC's and PSNC's North Carolina retail customers receive the benefit of a "most-favored-nation" status with regard to the provision of Merger benefits and protections among Georgia, South Carolina, and any other jurisdiction where approval of the Merger is required, by increasing the benefits and protections to DENC's or PSNC's retail North Carolina customers to match the greatest level of benefits and protections provided to DENC's or PSNC's retail customers in other jurisdictions, if applicable. The most favored nation clause protects North Carolina retail ratepayers of DENC and PSNC by ensuring that they receive at least equal customer benefits if the settlement stipulations and orders entered in other jurisdictions contain materially better benefits for DENC's and PSNC's ratepayers. Regulatory Condition 16.5 therefore provides that following the approval of the Merger in other jurisdictions, any mechanisms adopted pursuant to which benefits and ratepayer protections are provided to DENC and PSNC ratepayers will be reviewed to identify the states in which each of DENC's and/or PSNC's retail customers will receive the largest financial (including, but not limited to, rate reductions, rebates, refunds, other payments, bill credits, rate moratoriums, etc.) and non-financial benefits, and other ratepayer protections, on a per customer or pro rata basis. If the application of those benefits to DENC's and/or PSNC's North Carolina retail ratepayers would result in a greater level of benefits and/or protections than that which has otherwise been provided for their North Carolina retail customers in these Regulatory Conditions, then the benefits and protections to North Carolina retail ratepayers will be increased to match the greatest level of benefits and protections provided to the DENC and/or PSNC retail ratepayers in any of the other jurisdictions. The condition, however, provides that in no event will the application of the methodology cause North Carolina retail customers' benefits to be reduced.

The Commission finds and concludes that these Regulatory Conditions will effectively ensure that the benefits of the Merger are equal to or surpass the costs of the Merger to DENC's and PSNC's customers.

With regard to Findings of Fact Nos. 35-46, the Regulatory Conditions provide the protections noted in each such finding of fact. No party has offered evidence contesting these provisions of the Regulatory Conditions or the testimony of the witnesses in support thereof. As a result, the Commission determines that the evidence is sufficient to support these findings of fact and need not be repeated here.

With regard to all of the Regulatory Conditions approved herein, with the exception of Section VI (PJM Conditions) and XVI, the Regulatory Conditions are substantially similar to those approved by the Commission in the Duke-Piedmont Merger Order, as modified by the Duke-Piedmont Amended Conditions Order. In turn, those Regulatory Conditions are, with certain exceptions as approved in the Amended Conditions Order, identical to those approved in the 2006 merger of Duke Energy and Cinergy Corporation, and the 2012 merger of Duke Energy and Progress Energy, Inc. Thus, the Commission and the Public Staff have more than a decade of experience with the application and enforcement of the majority of these Regulatory Conditions.

The Commission has found them to be effective in protecting customers from the real and potential risks of those mergers. Additionally, the Commission has concluded that the Stipulation, including the Regulatory Conditions, was the product of give-and-take settlement negotiations among the parties. The Commission is, therefore, confident in the ongoing strength of the Regulatory Conditions as modified for this proceeding, and their ability to protect DENC's and PSNC's North Carolina retail customers from the real and potential risks of SCANA's Merger with Dominion Energy.

The Commission has carefully reviewed and considered all of the evidence set forth above and finds it to be credible and entitled to substantial weight. Based on the testimony and for the reasons discussed above, the Commission concludes that the Regulatory Conditions safeguard customers from potential adverse impacts of the Merger on rates, services, and other aspects of the public utility operations of DENC and PSNC as much as reasonably possible.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 47-51

The evidence supporting these findings of fact is set forth in the testimony of the Public Staff Panel, the testimony of Applicants' witnesses, and the Stipulation, including the Code of Conduct.

Potential risks to customers of the Merger are also addressed by the Code of Conduct. As with the proposed Regulatory Conditions, the proposed Code of Conduct would update the codes of conduct currently in effect and applicable to DENC and PSNC, and is largely based on the Code of Conduct that was approved by the Commission in the Duke-Piedmont Merger Order.

The Public Staff Panel testified that its proposed Code of Conduct, together with the Regulatory Conditions, were developed in order to provide cost allocation and pricing standards, natural gas marketing standards, requirements regarding the sharing of potentially competitive sensitive information, and requirements to file cost allocation manuals and annual reports on affiliate transactions, all of which would work to minimize any market power of the proposed Merger. Tr. p. 165.

Applicants' witness Wohlfarth testified that the Code of Conduct governs the relationship, activities, and transactions among the public utility operations and their affiliates. Tr. p. 97. Applicants' witness Harris testified that, together with the Regulatory Conditions, the Code of Conduct provides additional benefits and protections for PSNC's customers, ensures that the Merger will not adversely impact the rates charged and service provided by PSNC to its North Carolina customers, and ensures that the benefits of the Merger to PSNC's customers are sufficient to offset any potential costs and risks. Tr. pp. 86-88.

Section III.A of the Code of Conduct (Code) discusses Independence and Information Sharing. This section requires Dominion Energy, DENC, PSNC, and other affiliates to operate independently of each other, and sets guidelines and restrictions on the exchange of customer information and confidential systems operation information.

Section III.B of the Code addresses Nondiscrimination. It prohibits the Applicants from giving any preference in pricing or service priority to an affiliate or from requiring the purchase of any goods or services in return for receiving electric or gas service.

Section III.C of the Code addresses Marketing. It allows joint sales and joint advertising by DENC and PSNC with their affiliates and nonpublic utility operations subject to restrictions imposed by the Commission, but requires DENC and PSNC to make any such joint marketing opportunities available to third parties. This section of the Code also prohibits the use by an affiliate, including Dominion Energy, of DENC's or PSNC's names and logos unless disclaimers accompany such use. The disclaimers clarify that the utilities/affiliates are separate companies and that the Commission does not regulate Dominion Energy or the affiliate.

Section III.D of the Code addresses Transfers of Goods and Services, Transfer Pricing, and Cost Allocation. This section sets guidelines for the pricing of goods and services exchanged between affiliates.

Provisions D.4 and D.6 provide that charges for shared services and all permitted transactions among the affiliates shall be allocated to the affiliated utilities in accordance with the Service Company cost allocation manual filed with the Commission.

Provision D.5 provides that DENC, PSNC, and their utility affiliates may "capture economies-of-scale in joint purchases of goods and services" (excluding the purchase of electricity or ancillary services purchased for resale unless purchased pursuant to a Commission-approved contract or service agreement) if the joint purchases result in cost savings for customers.

Provision D.8 provides that trade secrets shall not be transferred from DENC or PSNC to Dominion Energy or other affiliates without just compensation and filing of 60-day prior notice to the Commission.

Provision D.9 provides that DENC and PSNC shall receive compensation from Dominion Energy or other affiliates for intangible benefits, if appropriate.

Section III.E, "Regulatory Oversight," reiterates that N.C. Gen. Stat. § 62-153 will continue to apply to all transactions between DENC, PSNC, Dominion Energy, and other affiliates. This statute requires all public utilities to file with the Commission any contract with any affiliate, and the Commission may disapprove such contract if it is found to be unjust or unreasonable. Further, the books and records of the Applicants and their affiliates will be open for examination by the Commission or the Public Staff. Finally, DENC shall file a report with its annual fuel cost recovery rider demonstrating that any gas services purchased from PSNC (except those provided under Commission-approved contracts) were prudent and reasonably priced.

Section III.F is entitled "Utility Billing Format" and provides that if customers receive bills for a variety of services such bills shall clearly separate the electric service charges and gas service charges from the charges for any other services. In addition, the bill shall clearly state that a customer's utility service will not be terminated for failure to pay for any other services billed.

Section III.G of the Code provides a "Complaint Procedure" for resolving complaints that arise due to the relationship of DENC and PSNC with Dominion Energy and other affiliates.

Section III.H is entitled "Natural Gas/Electricity Competition" and provides that DENC and PSNC shall continue to compete against all energy providers to serve those retail customer energy needs that can be legally and profitably served by both electricity and natural gas. The competition between DENC and PSNC shall be at a level that is no less than that which existed prior to the Merger. Without limitation as to the full range of potential competitive activity, DENC and PSNC shall maintain certain minimum standards.

The Commission has reviewed the Code of Conduct and finds and concludes that it represents significant commitments by the Applicants to provide ongoing protection to customers from possible costs and risks of the proposed Merger.

Also applicable is N.C. Gen. Stat. § 62-138, the requirement to obtain Commission approval over service contracts; N.C. Gen. Stat. § 62-140, the prohibition against discrimination; and, as discussed previously, N.C. Gen. Stat. § 62-153, which requires the Applicants to file affiliated contracts and to obtain approval for affiliated service contracts. Each of these statutory provisions either prohibits or mandates utility conduct for the purpose of assuring that rates charged to customers for utility services are just and reasonable.

The Commission has carefully reviewed and considered all of the evidence set forth above and finds it to be credible and entitled to substantial weight.

Further, the Code of Conduct is essentially identical to the Code of Conduct approved by the Commission in the Duke-Piedmont Merger Order, which, in turn, was essentially identical to the Code of Conduct approved in the 2006 merger of Duke Energy and Cinergy Corporation and the 2012 merger of Duke Energy and Progress Energy, Inc. Thus, the Commission and the Public Staff have more than a decade of experience with the application and enforcement of the Code of Conduct. The Commission has found the Code of Conduct to be effective in protecting ratepayers from the real and potential risks of those mergers. The Commission is, therefore, confident in the ongoing strength of the Code of Conduct and its ability to protect PSNC's customers from the real and potential risks of SCANA's Merger with Dominion Energy.

Based on the foregoing, the Commission finds and concludes that potential risks of the Merger to customers have been effectively mitigated as much as reasonably possible by the commitments of the Applicants in the Application, as well as the testimony of Applicants' witnesses, the testimony of the Public Staff Panel, and the Stipulation, including the Regulatory Conditions and Code of Conduct.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 52

The evidence supporting this finding of fact is contained in the Market Power Analysis, the testimony of Applicants' witness Hunger, the testimony of the Public Staff Panel, the testimony of Transco witness Amezquita, and the Stipulation, including the stipulated Regulatory Conditions and Code of Conduct.

ELECTRIC – MERGER

In the M-100, Sub 129 Order, the Commission required natural gas and electric utilities proposing to engage in a merger to file a market power analysis with their merger approval petitions. The purpose of this requirement was to allow the Commission to evaluate the impact of the proposed merger on competitive and regulated markets and to assess whether any potential anticompetitive effects might flow from the proposed merger.

The Commission has carefully reviewed the record in this proceeding related to these issues and finds no substantial evidence that would support the conclusion that the proposed Merger will result in materially increased market or monopoly power, particularly when viewed in the light of the restrictions and requirements set forth in the stipulated Regulatory Conditions and Code of Conduct.

In this regard, the Commission has reviewed the HHI study performed by Charles River Associates (CRA), which concludes that the proposed Merger does not raise competitive concerns in any of the studied markets. Market Power Analysis, Application Exhibit 5, at p. 24. Further, the Market Power Analysis found that the wholesale gas market is "moderately concentrated, and the proposed transaction will increase market concentration, but it will remain moderately concentrated" and that planned pipeline development in the region "would not raise competitive concerns, and would improve market supply and competitive alternatives." Id. at 24. Regarding wholesale electricity, "[w]ithin North Carolina, there will be no change in ownership of generation, and therefore no concentration of the market that would raise concerns over the exercise of market power." Id. at 24. The analysis also found that "there is no overlap in service territories between retail gas service provided by PSNC Energy (retail gas) and Dominion Energy North Carolina (retail electricity) so there is no concern about reduced competition for utility customers who have the ability to switch between electricity and gas for certain needs ... [t]hus, the proposed transaction should not raise concerns that, following the merger, there will be incentives to invest in one type of infrastructure over another to the disservice of its ratepayers." Id. at 24.

Applicants' witness Hunger testified in support of the Market Power Analysis and concluded that the Merger does not raise competitive concerns in any studied markets and will not create an increased ability to exercise market power. Witness Hunger stated that in the market power analysis he addressed the full range of competitive concerns in gas and electricity markets associated with the Merger as it relates to North Carolina. With regard to the wholesale gas market, he stated that the Merger would increase the market concentration, but that the market would remain moderately concentrated. With regard to the wholesale electricity market, he testified that within North Carolina there likely will be a slight increase in market concentration, but no harm to competition as a result. With regard to the retail gas and retail electricity markets, as there is no competitive retail regime for gas service or electricity service in North Carolina, he concluded that the Merger will not impact retail gas competition or retail electricity competition. With regard to cross-fuel competition, witness Hunger noted that there is no overlap in service territories between retail service provided by PSNC and DENC, so there is no concern about reduced competition for utility customers who have the ability to switch between electricity and natural gas for certain needs. He also concluded that the Merger should not raise concerns that following the Merger there will be incentives to invest in one type of infrastructure over another to the disservice of customers. Tr. pp. 69-70.

The Public Staff Panel testified that its review of witness Hunger's testimony, Applicants' joint application under Section 203 of the Federal Power Act, and the July 12, 2018 FERC order approving the Merger support a conclusion that the Merger is in the public interest. The Public Staff Panel noted FERC's recognition that there is no geographic overlap of the DENC and PSNC service areas. The Public Staff Panel testified further that its recommended Regulatory Conditions and Code of Conduct provide cost allocation and pricing standards, natural gas marketing standards, requirements regarding the sharing of potentially competitive sensitive information, and requirements to file cost allocation manuals and annual reports on affiliate transactions that should work to minimize any market power of the merged company. Tr. pp. 164-65.

Transco witness Amezquita testified that the Merger would create a vertically integrated business structure that could have significant control over essential facilities in the sale, distribution, and transmission of natural gas and electricity in North Carolina, which could lead to decisions by the merged company that could result in North Carolina customers paying higher prices. As noted above, Transco advocated for conditions on any approval of the Merger including requiring PSNC to issue a request for proposals for additional pipeline capacity, the filing of confidential reports of any resulting negotiations, and requiring PSNC to use a "least cost" standard when contracting for natural gas supply and services. Tr. pp. 127-128, 131-34.

As indicated by the Commission's questions for witness Hunger in its Order Granting in Part Motion to Excuse Several Witnesses and Requiring Late-Filed Exhibit, the Commission had some concern about CRA's conclusions regarding available pipeline capacity. Specifically, on page 8 of the CRA analysis, CRA employed a proxy for the total pass-through capacity available in Zone 5 on January 8, 2017, PSNC's peak day in 2017, and concluded that 1,020 MDth/d, 22% of the total market, was available as firm capacity. As indicated by the Commission's Question No. 1 to witness Hunger, the Commission was not persuaded that this proxy was applicable, particularly given that January 8, 2017, was not a design day for PSNC. As a result, there may have been released capacity available that day that could not be considered firm. Witness Hunger's answer to the Commission's Question No. 1 did not effectively address the Commission's concern. Nonetheless, aside from that point the Commission finds the conclusions of the Market Power Analysis to be acceptable and entitled to substantial weight. The Commission also finds the testimony of the Public Staff Panel on this matter to be entitled to substantial weight. Finally, the Commission finds that the testimony of Transco on this matter is effectively addressed by the evidence presented by the Market Power Analysis and the Public Staff Panel, and by the Stipulation.

With respect to the possibility of self-dealing or anti-competitive conduct by and among DENC and PSNC after the Merger, the Commission finds that risk to be effectively mitigated by the stipulated Regulatory Conditions and Code of Conduct, and by the ongoing authority of the Commission over the rates, terms, and conditions of service offered by DENC and PSNC.

The Regulatory Conditions and Code of Conduct, as set forth in the Stipulation and supported by the testimony of Applicants' witnesses Wohlfarth and Harris, address several areas in which self-dealing or anticompetitive behavior by DENC and PSNC could arise. The affiliated transaction rules set forth in the Regulatory Conditions are intended to address risks related to agreements and transactions between and among DENC, PSNC, and their affiliates; financing transactions involving Dominion Energy, DENC or PSNC, and any affiliate (Regulatory Condition Section III); and the proper incurrence of, accounting for, and direct charging, assignment, or allocation of costs incurred by DENC and PSNC (Regulatory Condition Sec. IV).The affiliate related provisions of the Code of Conduct are designed to ensure independence of DENC and PSNC and their affiliates, prohibit discrimination by DENC or PSNC against non-affiliates, and regulate joint marketing and transfer pricing. According to the Public Staff Panel's testimony, these provisions appropriately address concerns raised by the proposed Merger.

Based on the foregoing evidence, the Commission concludes that the proposed Merger will not result in materially increased market or monopoly power to the detriment of customers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 53

The evidence supporting this finding of fact is contained in the Stipulation, the testimony of Applicants' witnesses Wohlfarth and Harris, and the testimony of the Public Staff Panel.

As fully discussed in the Evidence and Conclusions for Findings of Fact Nos. 15 and 16, the provisions of the Stipulation are the product of the give-and-take of settlement negotiations between the Applicants, the Public Staff, and Transco. As a result, the Stipulation reflects the fact that the Applicants agreed to certain provisions that advanced the Public Staff's interests and the Public Staff agreed to other provisions that advanced the Applicants' interests. It also reflects the Applicants' agreement to provisions that addressed Transco's concerns and Transco's agreement to provisions that advanced Applicants' interests. The end result is that the Stipulation strikes a fair balance between the interests of the Applicants and their customers.

In his supplemental testimony, Applicants' witness Wohlfarth testified that, following the Public Staff's extensive audit and discovery process investigating the public convenience and necessity of the proposed Merger, the Applicants and the Public Staff began discussions regarding a possible settlement. He also stated that, after intervenor testimony was filed, the Applicants engaged in discussions with Transco regarding the Regulatory Conditions. He testified that the negotiations involved substantial compromise by all parties on numerous issues. Witness Wohlfarth testified further that the terms of the Stipulation, including the Regulatory Conditions and Code of Conduct, will ensure that the Merger will have no adverse impact on the rates charged and the services provided by DENC and PSNC to North Carolina customers and that the benefits of the Merger to those customers are sufficient to offset any potential costs and risks. He stated that PSNC will continue to provide efficient, reliable, and safe service at a reasonable cost through the many commitments made by Dominion Energy and SCANA and testified to his belief that approval of the Merger and the Stipulation will benefit PSNC and its customers. Tr. pp. 91, 99-100. In his supplemental testimony, Applicants' witness Harris testified to a number of ways that PSNC will benefit from the Merger, and that the terms of the Stipulation, Regulatory Conditions, and Code of Conduct will ensure that the Merger will not result in adverse impacts to PSNC's rates and service. Tr. pp. 82-84.

The Commission finds and concludes that the Stipulation is a reasoned and balanced resolution of the matters that might otherwise be in dispute between the Stipulating Parties in this docket. Further, the Stipulation is just and reasonable to all parties in light of the evidence presented and serves the public interest. Therefore, the Commission approves the Stipulation in its entirety. In addition, the Commission finds and concludes that the Stipulation is entitled to substantial weight and consideration in the Commission's decision in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 54

The evidence supporting this finding of fact is contained in the Application, the Applicants' testimony, Public Staff Panel testimony, the Stipulation, including the Regulatory Conditions and Code of Conduct, and the Commission's supervisory authority under Chapter 62 of the General Statutes over the rates, terms, and conditions of service provided to the public by DENC and PSNC.

Pursuant to N.C. Gen. Stat. § 62-111(a), the Commission is required to determine whether the proposed merger is "justified by the public convenience and necessity." Upon such finding, the statute instructs that approval of the proposed merger "shall be given."

In prior merger proceedings the Commission has established a three-part test for determining whether a proposed utility merger is justified by the public convenience and necessity. That test is (1) whether the merger would have an adverse impact on the rates and services provided by the merging utilities; (2) whether ratepayers would be protected as much as possible from potential costs and risks of the merger; and (3) whether the merger would result in sufficient benefits to offset potential costs and risks. See Order Approving Merger Subject to Regulatory Conditions and Code of Conduct (Duke/Progress Merger Order), issued June 29, 2012, in Docket Nos. E-2, Sub 998 and E-7, Sub 986, aff'd, In re Duke Energy Corp., 232 N.C. App. 573, 755 S.E.2d 382 (2014); see also Duke- Piedmont Merger Order. These questions are related to one another and together establish a reasoned framework upon which utility mergers may be evaluated. In making these assessments, the Commission has also examined factors such as whether service quality will be maintained or improved, the extent to which costs can be lowered and rates can be maintained or reduced, and whether effective regulation of the merging utilities will be maintained. See Order Approving Merger and Issuance of Securities, issued April 22, 1997, in Docket No. E-7, Sub 596.

The Commission has made findings of fact regarding the substantial economic and non-economic benefits to be received by customers as a result of the Merger. In addition, the Commission notes the absence of any proposal to change rates, terms, or conditions of service for any customer of DENC or PSNC in conjunction with or as a direct result of the proposed Merger. This is confirmed in the testimony of Applicants' witness Farrell that "no transaction fees, integration cost, or any acquisition premium that will result from the combination will be passed on to the customers of PSNC or Dominion Energy North Carolina." Tr. p. 24. It is also confirmed by Paragraph No. 30.i. of the Application, which provides that the Merger will "not have a net adverse impact on the rates and services of Dominion Energy North Carolina or PSNC Energy." Additionally, the Cost-Benefit Analysis filed with the Application indicates that customers will not be charged for Merger costs such as the acquisition premium and transaction fees, which, instead, will be absorbed by Dominion Energy. Finally, the Stipulation provides that direct expenses associated with the Merger will be excluded from the regulated expenses of PSNC and DENC for Commission financial reporting and ratemaking purposes.

Further, the Commission concludes that the potential risks or costs attendant to the proposed Merger are adequately mitigated by the Applicants' commitments concerning absorption of Merger-related expenses and by the restrictions imposed on the Applicants' conduct by the Stipulation, the Regulatory Conditions and Code of Conduct, and by this Commission's continuing jurisdiction and authority over the rates, terms, and conditions of service provided by DENC and PSNC. Finally, the Commission has given appropriate weight to the Applicants' testimony that the Merger will also result in non- quantifiable economic and non-economic benefits for the customers of DENC and PSNC. On balance, the Commission concludes that the Merger will have no adverse impact on the rates and services provided by DENC and PSNC to their North Carolina customers and that the known and potential benefits of the Merger are sufficient to offset the potential costs and risks.

In addition, the Commission has made findings of fact that the Regulatory Conditions, Code of Conduct, and other provisions of the Stipulation, as approved herein, will protect DENC's and PSNC's North Carolina retail customers from known and potential costs and risks of the Merger.

Therefore, the Commission concludes that the proposed Merger of Dominion Energy and SCANA is justified by the public convenience and necessity, serves the public interest, and should be approved pursuant to N.C. Gen. Stat. § 62-111.

IT IS, THEREFORE, ORDERED as follows:

1. That the Application of Dominion Energy and SCANA pursuant to N.C. Gen. Stat. § 62-111(a) to engage in a business combination transaction shall be, and is hereby, approved subject to the provisions of the Stipulation and of the revised Regulatory Conditions and Code of Conduct, attached hereto as Appendix A and incorporated herein.

2. That subject to the Merger being consummated and the Regulatory Conditions and Code of Conduct approved herein becoming effective, the Regulatory Conditions and Codes of Conduct approved by the Commission in the Dominion Energy- Consolidated Natural Gas merger order and the SCANA-PSNC merger order shall be nullified.

3. That upon closing of the Merger PSNC shall create a regulatory liability of \$3.75 million and shall refund that amount to its North Carolina customers through bill credits of \$1.25 million each provided on January 1, 2019 (or as soon thereafter as possible), January 1, 2020, and January 1, 2021.

4. That in 2019 PSNC shall increase its charitable contributions over its 2017 contributions by \$150,000. Such charitable contributions shall be used to provide energy assistance to low-income customers in PSNC's service territory and shall be treated as below-the-line expenses for regulatory accounting, reporting, and ratemaking purposes.

5. That DENC and PSNC shall exclude direct expenses associated with the Merger from their regulated expenses for Commission financial reporting and ratemaking purposes. Such expenses to be excluded include: acquisition premiums; change-in- control payments made to terminated executives; regulatory process costs; transaction costs such as investment banking, legal, accounting, securities issuances, and advisory fees; integration costs such as costs related to the integration of financial, IT, human resources, billing, accounting, and telecommunications

systems; and other transition costs such as severance payments, changes to signage, transitioning employees to post- Merger employee benefit plans, and costs to terminate any duplicative leases, contracts and operations. PSNC and DENC shall file a report of their accounting for Merger-related direct expenses within 60 days after the close of the Merger, and supplemental reports within 60 days after each calendar year, as necessary.

6. That PSNC will not file an application for a general rate case proceeding to adjust its rates and charges before April 1, 2021. PSNC will not increase its non-gas cost margin in its rates until November 1, 2021, except for the following reasons: (1) adjustments or changes pursuant to Rider C (Customer Usage Tracker), Rider D (Purchased Gas Adjustment Procedures), and Rider E (Integrity Management Tracker) pursuant to N.C. Gen. Stat. § 62-133.4, N.C. Gen. Stat. § 62-133.7, and N.C. Gen. Stat. § 62-133.7A; (2) to reflect the financial impact of governmental action (legislative, executive, or regulatory) having a substantial specific impact on the gas industry generally or on a segment thereof that includes PSNC, including but not limited to major expenditures for environmental compliance; (3) to implement natural gas expansion surcharges imposed pursuant to N.C. Gen. Stat. § 62-158; or (4) to reflect the financial impact of major expenditures associated with force majeure. In addition, PSNC shall not file for any cost deferral during or covering any period from the date of this Order until after October 31, 2021, except: (1) to reflect the financial impact of governmental action (legislative, executive, or regulatory) having a substantial specific impact on the gas industry generally or on a segment thereof that includes PSNC, including but not limited to major expenditures for environmental compliance; or (2) to reflect the financial impact of major expenditures associated with force majeure.

7. That no later than March 1, 2019, and in accordance with and as provided by N.C. Gen. Stat. § 62-153 and the related Regulatory Conditions, DENC and PSNC shall file any new or amended affiliate agreements for use by DENC and PSNC. DENC and PSNC may operate, as of the date of the Merger's closing, under the new or amended affiliate agreements until the Commission issues an order approving or accepting the new or amended affiliate agreements under N.C. Gen. Stat. § 62-153. DENC's and PSNC's interim operations under the new or amended affiliate agreements shall be subject to any fully adjudicated Commission order on the matter.

8. That the Stipulation is hereby approved in its entirety.

9. That the Applicants are authorized to take such other and further actions as are reasonable and necessary to consummate the Merger transaction set forth in the Merger Agreement subject to the terms hereof.

10. That Applicants shall file a written notice in this docket within ten (10) days of the consummation of the Merger approved herein.

11. That these dockets shall remain open pending the filing of such notice and further orders of the Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of November, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

Commissioner Lyons Gray did not participate in this decision.

APPENDIX A

DOCKET NO. E-22, SUB 551
DOCKET NO. G-5, SUB 585

REGULATORY CONDITIONS

These Regulatory Conditions set forth commitments made by Dominion Energy and SCANA, and their public utility subsidiaries, DENC and PSNC, respectively, as a precondition of approval of the application by Dominion Energy and SCANA pursuant to G.S. 62-111(a) for authority to engage in their proposed business combination transaction. These Regulatory Conditions, which become effective only upon closing of the Merger, shall apply jointly and severally to Dominion Energy and SCANA, as well as DENC and PSNC and shall be interpreted in the manner that most effectively fulfills the Commission's purposes as set forth in the preamble to Section II of these Regulatory Conditions.

SECTION I
DEFINITIONS

For the purposes of these Regulatory Conditions, capitalized terms shall have the meanings set forth below. If a capitalized term is not defined below, it shall have the meaning provided elsewhere in this document or as commonly used in the electric or natural gas utility industry.

Affiliate: Dominion Energy, and any business entity of which ten percent (10%) or more is owned or controlled, directly or indirectly, by Dominion Energy. For purposes of these Regulatory Conditions, Dominion Energy and each business entity so controlled by it are considered to be Affiliates of DENC and PSNC, and DENC and PSNC are considered to be Affiliates of each other.

Affiliate Contract: (a) Any contract or agreement between DENC and PSNC or between DENC or PSNC and any other Affiliate or proposed Affiliate, and (b) any contract or agreement between such other Affiliate or proposed Affiliate and another Affiliate that is related to the same subject matter and is reasonably likely to have an Effect on DENC's or PSNC's Rates or Service. Such contracts and agreements include, but are not limited to, service, operating, interchange, pooling, and wholesale power sales agreements and agreements involving financings and asset transfers and sales.

Code of Conduct: The minimum guidelines and rules approved by the Commission that govern the relationships, activities, and transactions between and among the public utility operations of DENC and PSNC, Dominion Energy and SCANA, the other Affiliates of DENC and PSNC, and the Nonpublic Utility Operations of DENC and PSNC, as those guidelines and rules may be amended by the Commission from time to time.

Commission: The North Carolina Utilities Commission.

CNG: Consolidated Natural Gas Company, which merged with Dominion Resources, Inc. (now Dominion Energy) in 1999 as approved by the Commission in Docket No. E-22, Sub 380.

Customer: Any retail electric customer of DENC in North Carolina and any Commission-regulated natural gas sales or natural gas transportation customer of PSNC located in North Carolina.

DENC: Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina, the business entity, wholly owned by Dominion Energy, that holds the franchises granted by the Commission to provide Electric Services within its North Carolina service territory and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina. DENC refers to the system business and operation of Virginia Electric and Power Company, and not simply the North Carolina retail assigned or allocated portions of that business and operation.

Dominion Energy: Dominion Energy, Inc., which is the current holding company parent of DENC and PSNC, and any successor company.

Effect on DENC's or PSNC's Rates or Service: When used with reference to the consequences to DENC or PSNC of actions or transactions involving an Affiliate or Nonpublic Utility Operation, this phrase has the same meaning that it has when the Commission interprets G.S. 62-3(23)(c) with respect to the affiliation covered therein.

Electric Services: Commission-regulated electric power generation, transmission, distribution, delivery, and retail sales, and other related services, including, but not limited to, administration of Customer accounts and rate schedules, metering, billing, standby service, backups, and changeovers of electric service to other suppliers.

Federal Law: Any federal statute or legislation, or any regulation, order, decision, rule or requirement promulgated or issued by an agency or department of the federal government.

FERC: The Federal Energy Regulatory Commission.

Fully Distributed Cost: All direct and indirect costs, including overheads and an appropriate cost of capital, incurred in providing the goods and services in question.

Joint Owners: Old Dominion Electric Cooperative (ODEC), with respect to its ownership interests in the North Anna Nuclear Station and the Clover Power Station, and First Energy and LS Power (and/or their subsidiaries and affiliates), with regard to their ownership interests in the Bath County Pumped Storage Station. For purposes of these Regulatory Conditions, DENC is not included in the definition of Joint Owners. Also, for purposes of these Regulatory Conditions, Joint Owners include any successors and assigns to ODEC and First Energy.

Market Value: The price at which property, goods, or services would change hands in an arm's-length transaction between a buyer and a seller without any compulsion to engage in a transaction, and both having reasonable knowledge of the relevant facts.

Merger: All transactions contemplated by the Agreement and Plan of Merger between Dominion Energy and SCANA.

Merger-Related Expenses: Merger–Related Expenses include acquisition premiums, change-in-control payments made to terminated executives, regulatory process costs, and transaction costs, such as investment banking, legal, accounting, securities issuances and advisory fees. Integration costs include the integration of financial, IT, human resources, billing, accounting, and telecommunications systems. Other transition costs include severance payments to employees, changes to signage, the cost of transitioning employees to post-merger employee benefit plans, and costs to terminate any duplicative leases, contracts and operations, etc.

Native Load Priority: Power supply service being provided or electricity otherwise being sold with a priority of service equivalent to that planned for and provided by DENC to its respective Retail Native Load Customers.

Natural Gas Services: Commission-regulated natural gas sales and natural gas transportation, and other related services, including, but not limited to, administration of Customer accounts and rate schedules, metering and billing, and standby service.

Nonpublic Utility Operations: All business operations engaged in by DENC or PSNC involving activities (including the sales of goods or services) that are not regulated by the Commission or otherwise subject to public utility regulation at the state or federal level.

Non-Utility Affiliate: Any Affiliate, including Service Company, other than a Utility Affiliate, DENC, or PSNC.

PSNC: Public Service Company of North Carolina, Inc., the business entity, wholly owned by Dominion Energy and SCANA, that holds the franchise granted by the Commission to provide Natural Gas Services within its North Carolina service territory and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

Public Staff: The Public Staff of the North Carolina Utilities Commission.

Purchased Power Resources: Purchases of energy by DENC at wholesale, the contract terms for which are one year or longer.

Retail Native Load Customers: The captive retail Customers of DENC in North Carolina for which DENC has the obligation under North Carolina law to engage in long-term planning and to supply all Electric Services, including installing or contracting for capacity, if needed, to reliably meet their electricity needs.

Retained Earnings: The retained earnings currently required to be listed on page 112, line 11, of the pre-Merger DENC FERC Form 1 and page 112, line 11 of the pre-Merger PSNC FERC Form 2.

SCANA: SCANA Corporation, which is the former and current direct holding company parent of PSNC and is a subsidiary of Dominion Energy, and any successors.

Service Company: A centralized service company Affiliate that provides Shared Services to DENC, PSNC, other Affiliates, and/or the Nonpublic Utility Operations of DENC or PSNC, singly or in any combination.

Shared Services: The services that meet the requirements of these Regulatory Conditions and that the Commission has explicitly authorized DENC and PSNC to take from the Service Company pursuant to a service agreement (a) filed with the Commission pursuant to G.S. 62-153(b), thus requiring acceptance and authorization by the Commission, and (b) subject to all other applicable provisions of North Carolina law, the rules and orders of the Commission, and these Regulatory Conditions.

Utility Affiliates: The regulated public utility operations of the East Ohio Gas Company (Dominion Energy Ohio), Hope Gas, Inc. (Dominion Energy West Virginia), Questar Gas Company (Dominion Energy Utah, Dominion Energy Wyoming, and Dominion Energy Idaho), and South Carolina Electric & Gas Company (SCE&G).

SECTION II
AUTHORITY, SCOPE, AND EFFECT

These Regulatory Conditions are based on the general power and authority granted to the Commission in Chapter 62 of the North Carolina General Statutes to control and supervise the public utilities of the State. The Regulatory Conditions address specific exercises of the Commission's authority and provide mechanisms that enable the Commission to determine the extent of its authority and jurisdiction over proposed activities of, and transactions involving, DENC, PSNC, Dominion Energy, and other Affiliates or Nonpublic Utility Operations. The purpose of these Regulatory Conditions is to ensure that DENC's Retail Native Load Customers and PSNC's Customers (a) are protected from any known adverse effects from the Merger, (b) are protected as much as possible from potential costs and risks resulting from the Merger, and (c) receive sufficient known and expected benefits to offset any potential costs and risks resulting from the Merger. These Regulatory Conditions are not intended to impose legal obligations on entities in which Dominion Energy does not directly or indirectly have a controlling voting interest, or to affect any rights of any party to participate in subsequent proceedings.

2.1 Commission Authority Over Certain Transactions. DENC, PSNC, Dominion Energy, and other Affiliates acknowledge that the Commission has authority over intra-company transactions as provided for in Chapter 62.

2.2 Limited Right to Challenge Commission Orders. Other than as provided for, or explicitly prohibited, in these conditions, Dominion Energy, DENC, PSNC, and other Affiliates retain the right to challenge the lawfulness of any Commission order issued pursuant to or relating to these Regulatory Conditions on the basis that such order exceeds the Commission's statutory authority under North Carolina or Federal Law or the other grounds listed in G.S. 62-94(b).

2.3 Waiver Requests. DENC, PSNC, Dominion Energy, and other Affiliates may seek a waiver of any aspect of these Regulatory Conditions in a particular case or circumstance for good cause shown by filing such a request with the Commission.

SECTION III
PROTECTION OF RIGHTS

The following Regulatory Conditions are intended to protect the jurisdiction of the Commission as a result of the Merger, including risks related to agreements and transactions between and among DENC, PSNC, and any of their Affiliates; financing transactions involving Dominion Energy, DENC or PSNC, and any other Affiliate; and the ownership, use, and disposition of assets by DENC or PSNC.

3.1 Transactions between DENC, PSNC, and Other Affiliates; Notice of Affiliate Contracts to be Filed with the FERC.

(a) DENC and PSNC shall not engage in any transactions with Affiliates or proposed Affiliates without first filing the proposed contracts oragreements memorializing such transactions pursuant to G.S. 62-153 and taking such actions and obtaining from the Commission such determinations and authorizations as may be required under North Carolina law. DENC or PSNC, as applicable, shall submit each proposed Affiliate Contract or substantive amendment to an existing Affiliate Contract to the Public Staff for informal review at least 15 days before filing it with the Commission. If DENC or PSNC and the Public Staff agree within the 15-day period that the proposed Affiliate Contract or substantive amendment to an existing Affiliate Contract does not require any action by the Commission, DENC or PSNC may proceed to execute the agreement subject to later disapproval and voidance by the Commission pursuant to G.S. 62 - 153(a). Otherwise, the proposed Affiliate Contract or substantive amendment to an existing Affiliate Contract shall not be executed until the agreement has been filed and payment of compensation has been approved by the Commission pursuant to G.S. 62-153(b).

(b) In addition to the requirements of Regulatory Condition 3.1(a), for any contract requiring filing with FERC, DENC or PSNC shall file, for informational purposes, a copy of a proposed Affiliate Contract, a contract with a proposed Affiliate, or an amendment to an existing Affiliate Contract with the Commission at least 15 days prior to filing with FERC.

3.2 Financing Transactions Involving DENC, PSNC, Dominion Energy, or Other Affiliates.

(a) With respect to any financing transaction between or among DENC or PSNC and Dominion Energy or any one or more other Affiliates, any contract memorializing such transaction shall expressly provide that DENC or PSNC shall not enter into any such financing transaction except in accordance with North Carolina law and the rules, regulations, and orders of the Commission promulgated thereunder; and

(b) With respect to any financing transaction (i) between or among any of the Affiliates if such contracts are reasonably likely to have an Effect on DENC's or PSNC's Rates or Service, or (ii) between DENC and PSNC or between DENC or PSNC and any other Affiliate, any contract memorializing such transaction shall expressly provide that DENC or PSNC shall not include the effects of any capital structure or debt or equity costs associated with such financing transaction in its North Carolina retail cost of service or rates except as allowed by the Commission.

3.3 Ownership and Control of Assets Used by DENC and PSNC to Supply Electric Power or Natural Gas Services to North Carolina Customers; Transfer of Ownership or Control.

(a) DENC and PSNC shall own and control all assets or portions of assets used for the generation, transmission, and distribution of electric power or the transmission, storage, or distribution of natural gas to their respective Customers (with the exception of assets both (1) not otherwise owned or controlled by DENC or PSNC and (2) used to provide power purchased by DENC at wholesale or natural gas transportation to PSNC). This paragraph 3.3(a) shall also not apply to the ordinary course of the operation of DENC's transmission assets in accordance with its membership in PJM, Inc.

(b) With respect to the voluntary transfer by DENC or PSNC to Nonpublic Utility Operations, an Affiliate, and/or a non-Affiliate, of the control of, operational responsibility for, or ownership of any asset or portion thereof used for the transmission, distribution, generation, or other provision of electric power and/or service, or natural gas service, to customers in North Carolina:

(i) DENC or PSNC shall provide written notice to the Commission at least 30 days in advance of any proposed transfer falling under Section 3.3(b) with a net book value in excess of ten million dollars ($10 million). The provisions of Regulatory Condition 13.2 shall apply to an advance notice filed pursuant to this Regulatory Condition. DENC or PSNC shall not commit to or carry out such a transfer except in accordance with North Carolina law and the rules, regulations, and orders of the Commission promulgated thereunder; and

(ii) DENC or PSNC may not include in rates the value of any such transfer, except as allowed by the Commission in accordance with North Carolina law.

3.4 Purchases and Sales of Electricity and Natural Gas between DENC, PSNC, SCANA, Dominion Energy, Other Affiliates, or Nonpublic Utility Operations. Subject to additional restrictions set forth in the Code of Conduct, neither DENC or PSNC shall purchase electricity (or related ancillary services) or natural gas from Dominion Energy, another Affiliate, or a Nonpublic Utility Operation under circumstances where the total all-in costs, including generation, transmission, ancillary costs, distribution, taxes and fees, and delivery point costs, incurred (whether directly or through allocation), based on information known, anticipated, or reasonably available at the time of purchase, exceed fair Market Value for comparable service, nor shall DENC or PSNC sell electricity (or related ancillary services) or natural gas to Dominion Energy, another Affiliate, or a Nonpublic Utility Operation for less than fair Market Value; provided, however, that such restrictions shall not apply to emergency transactions.

3.5 Least Cost Integrated Resource Planning and Resource Adequacy. DENC shall retain the obligation to pursue least cost integrated resource planning for its regulated electric Customers and remain responsible for its own resource adequacy subject to Commission oversight in accordance with North Carolina law. DENC shall determine the appropriate self-built or purchased power resources to be used to provide future generating capacity and energy to its regulated electric Customers, including the siting considered appropriate for such resources, on the basis of the benefits and costs of such siting and resources to those regulated electric Customers.

3.6 Native Load Service. DENC shall continue to serve its Retail Native Load Customers with the lowest-cost power it can generate or purchase from other sources in order to meet its native load requirements in accordance with Condition No. 11.1 before making power available to customers that are not entitled to the same level of priority as Retail Native Load Customers. Before DENC executes any contract that grants Native Load Priority to a wholesale customer or to one or more retail customers of another entity, it shall, for informational purposes, provide the Public Staff with at least 15 days' written advance notice of its intent to grant Native Load Priority and to treat the retail native load of a proposed wholesale customer as if it were DENC's retail native load pursuant to this subsection and subsection 3.5.

3.7 Additional Provisions Regarding Wholesale Contracts Entered into by DENC as Seller.

(a) This Regulatory Condition does not apply to PSNC.
(b) The Commission retains the right to assign, allocate, impute, and make pro- forma adjustments with respect to the revenues and costs for retail ratemaking and regulatory accounting and reporting purposes.
(c) DENC acknowledges that when it enters into wholesale contracts that obligate DENC to construct generating facilities or make commitments to purchase capacity and energy to meet those contractual commitments such action constitutes

acceptance by DENC, Dominion Energy, and other Affiliates or Nonpublic Utility Operations thereof of the risks that investments in generating facilities or commitments to purchase capacity and energy to meet such contractual commitments and maintain an adequate reserve margin throughout the term of such contracts may become uneconomic sunk costs that may not be recoverable from DENC's Retail Native Load Customers. In a future Commission retail proceeding in which cost recovery is at issue, DENC shall not claim that it does not bear this risk, and DENC shall acknowledge that the Commission retains full authority under Chapter 62 to ascertain whether such costs are used and useful. For purposes of this condition, capacity will be considered used and useful and not excess capacity to the extent the Commission determines such capacity is needed by DENC to meet the expected peak loads of DENC's Retail Native Load Customers in the near term future plus a reserve margin comparable to that currently being used or otherwise considered appropriate by the Commission.

(d) Except as provided in the foregoing conditions, DENC retains the right to challenge the lawfulness of any order issued by the Commission in connection with the assignment, allocation, imputation, pro-forma adjustments to, or disallowances of the revenues and costs associated with DENC's wholesale contracts for retail ratemaking and regulatory accounting and reporting purposes on any other grounds, including but not limited to the rights outlined in G.S. 62-94(b).

3.8 Other Protections.

(a) DENC, PSNC, Dominion Energy, another Affiliate, and a Nonpublic Utility Operation shall not assert in any forum - whether judicial, administrative, federal, state, local or otherwise - that the Commission's authority to determine the reasonableness or prudence of DENC's or PSNC's decisions with respect to supply-side resources, demand-side management, or any other aspect of resource adequacy is limited.

(b) Any contract or filing regarding DENC's withdrawal from an RTO or comparable entity must be contingent upon state regulatory approval. This Regulatory Condition does not apply to PSNC.

(c) DENC and PSNC shall obtain Commission approval before the Service Company is sold, transferred, merged with any other entities, has any ownership interest therein changed, or otherwise changed so that a change of control could occur. This requirement does not apply to any movement of the Service Company within the Dominion Energy holding company system that does not constitute a change of control.

(d) DENC and PSNC may participate in joint comments and other joint filings with Affiliates only when such participation fully complies with both the letter and the spirit of the Regulatory Conditions. Any filing made by the Service Company on behalf of DENC or PSNC must clearly identify the Service Company as an agent of DENC or PSNC for purposes of making the filing.

(e) Neither DENC, PSNC, Dominion Energy, another Affiliate, nor a Nonpublic Utility Operation shall make any assertion or argument either on its own initiative or in support of any other entity's assertions in any forum - whether judicial, administrative, federal, state, or otherwise - with respect to any contract, transaction, or other matter in which DENC or PSNC is involved or proposes to be involved or any contract, transaction, or matter involving or proposed to involve Dominion Energy, any other Affiliate, or any Nonpublic Utility Operation that may have an Effect on DENC's or PSNC's Rates or Service, that any of the following actions exceed the Commission's power, authority or jurisdiction under North Carolina law:

(i) reviewing the reasonableness of any Affiliate commitment entered into or proposed to be entered into by DENC or PSNC, or disallowing the costs of, or imputing revenues related to such commitment to, DENC or PSNC;
(ii) exercising its authority over financings or setting rates based on the capital structure, corporate structure, debt costs, or equity costs that it finds to be appropriate for retail ratemaking purposes;
(iii) reviewing the reasonableness of any commitment entered into or proposed to be entered into by DENC or PSNC to transfer an asset;
(iv) mandating, approving, or otherwise regulating a transfer of assets by or to DENC or PSNC;
(v) scrutinizing and establishing the value of any asset transfers for the purpose of determining the rates for services rendered to DENC's Retail Native Load Customers or PSNC's Customers; or
(vi) exercising any other lawful authority it may have.

Should any other entity so assert, neither DENC, PSNC, Dominion Energy, other Affiliates, nor the Nonpublic Utility Operations shall support any such assertion and shall, promptly upon learning of such assertion, advise and consult with the Commission and the Public Staff regarding such assertion.

(f) DENC, PSNC, Dominion Energy, and any other Affiliates, and the Nonpublic Utility Operations shall (A) acknowledge the risk of any possible preemptive effects of Federal Law with respect to any contract, transaction, or commitment entered into or made or proposed to be entered into or made by DENC or PSNC, or which may otherwise affect DENC's or PSNC's operations, service, or rates and (B) shall take all actions as may be reasonably and lawfully necessary and appropriate to advance the interests of North Carolina ratepayers to avoid rate increases, foregone opportunities for rate decreases or any other adverse effects of such preemption including but not limited to intervention in FERC proceedings on behalf of the interests of North Carolina ratepayers.

3.9 <u>FERC Filings and Orders</u>. In addition to the filing requirements of Commission Rule R8-27 and all other applicable statutes and rules, and to keep the Commission informed of its activities, DENC shall, on a quarterly basis, file with the Commission the following: (a) a list of all active dockets at the FERC, including a sufficient description to identify the type of proceeding, in which DENC, Dominion Energy, or the Service Company on behalf of DENC or Dominion Energy is a party, with new information in each quarterly filing tracked; and (b) a list of the periodic reports filed by DENC, Dominion Energy, or the Service Company on behalf of DENC or Dominion Energy with the FERC, including sufficient information to identify the subject matter of each report and how each report can be accessed. These filings shall be made in Docket No. E-22, Sub 551D and updated regularly.

In addition, DENC shall serve on the Public Staff all of its FERC filed cost-based and market-based wholesale agreements and amendments; interconnection agreements and amendments for all generation facilities in DENC's North Carolina retail service territory and all generation facilities 20 megawatts or greater in size in the remainder of DENC's service territory; and any other filings made by DENC, Dominion Energy, or the Service Company on behalf of DENC or Dominion Energy with the FERC, to the extent these other filings are reasonably likely to have an Effect on DENC's Rates or Service. This Regulatory Condition does not apply to PSNC, as relevant FERC-related information is required to be filed with the Commission in annual gas cost prudence reviews.

SECTION IV
TREATMENT OF AFFILIATE COSTS AND RATEMAKING

The following Regulatory Conditions are intended to ensure that the costs incurred by DENC and PSNC are properly incurred, accounted for, and directly charged, directly assigned, or allocated to their respective North Carolina retail operations and that only costs that produce benefits to DENC's Retail Native Load Customers and PSNC's Customers are included in DENC's and PSNC's North Carolina cost of service for ratemaking purposes. The procedures set forth in Regulatory Condition 13.2 do not apply to an advance notice filed pursuant to Regulatory Condition 4.5.

4.1 Access to Books and Records. In accordance with North Carolina law, the Commission and the Public Staff shall continue to have access to the books and records of DENC, PSNC, Dominion Energy, other Affiliates, and the Nonpublic Utility Operations.

4.2 Procurement or Provision of Goods and Services by DENC or PSNC from or to Affiliates or Nonpublic Utility Operations. Except as to transactions between and among DENC and PSNC pursuant to filed and approved service agreements and lists of services, and subject to additional provisions set forth in the Code of Conduct, DENC and PSNC shall take the following actions in connection with procuring goods and services for their respective utility operations from Affiliates or Nonpublic Utility Operations and providing goods and services to Affiliates or Nonpublic Utility Operations:

(a) DENC and PSNC each shall seek out and buy all goods and services from the lowest cost qualified provider of comparable goods and services, and shall have the burden of proving that any and all goods and services procured from their Utility Affiliates, Non-Utility Affiliates, and Nonpublic Utility Operations have been procured on terms and conditions comparable to the most favorable terms and conditions reasonably available in the relevant market, which shall include a showing that comparable goods or services could not have been procured at a lower price from qualified non- Affiliate sources or that DENC or PSNC could not have provided the services or goods for itself on the same basis at a lower cost. To this end, no less than every four years DENC and PSNC shall perform comprehensive non-solicitation based assessments at a functional level of the market competitiveness of the costs for goods and services they receive from a Utility Affiliate, the Service Company, another Non-Utility Affiliate, and a Nonpublic

Utility Operation, including periodic testing of services being provided internally or obtained individually through outside providers. To the extent the Commission approves the procurement or provision of goods and services between or among DENC, PSNC, and the Utility Affiliates, those goods and services may be provided at the supplier's Fully Distributed Cost.

(b) To the extent they are allowed to provide such goods and services, DENC and PSNC shall have the burden of proving that all goods and services provided by either of them to Dominion Energy, a Non-Utility Affiliate, any other Affiliate, or a Nonpublic Utility Operation have been provided on the terms and conditions comparable to the most favorable terms and conditions reasonably available in the market, which shall include a showing that such goods or services have been provided at the higher of cost or market price. To this end, no less than every four years DENC and PSNC shall perform comprehensive, non-solicitation based assessments at a functional level of the market competitiveness of the costs for goods and services provided by either of them to a Utility Affiliate, the Service Company, another Non-Utility Affiliate, any other Affiliate, and a Nonpublic Utility Operation.

(c) The periodic assessments required by subdivisions (a) and (b) of this subsection may take into consideration qualitative as well as quantitative factors. To the extent that comparable goods or services provided to DENC or PSNC, or by DENC or PSNC are not commercially available, this Regulatory Condition shall not apply.

4.3 Location of Core Utility Functions.

(a) This Regulatory Condition does not apply to PSNC.

(b) Core utility functions are those functions related to Electric Services. Core utility functions do not include services of a governance or corporate type nature that have been traditionally provided by a service company, the specific services listed on the service company agreement services list for DENC filed with the Commission pursuant to Regulatory Condition 4.4(a), and roles that provide oversight to the enterprise and are not jurisdiction- specific (Excluded Functions). DENC shall annually review core utility function employees charging more or less than 50% of their time to DENC over a six-month period from January 1 to June 30. DENC shall annually file, on or before January 1, a report containing the results of the annual review. DENC may file a list of employees at the higher levels of management (not including those levels of management that report directly to the Chief Executive Officer for Dominion Energy) for their core utility functions that they propose to be Service Company employees in their annual filing. DENC shall also include in its annual filing a list of any DENC employee positions or functions that have been transferred to the Service Company, Dominion Energy, or another Affiliate during the preceding year, and the reason(s) for each transfer. DENC shall meet with the Public Staff no later than March 31 of each year, beginning in 2020, to review the results of the annual reviews and, to the extent necessary, develop a proposal for any appropriate modifications to this Condition 4.3.

4.4 Service Agreements and Lists of Services.

(a) DENC and PSNC shall file pursuant to G.S. 62-153 final proposed service agreements that authorize the provision and receipt of non-power goodsor services between and among DENC, PSNC, or their Affiliates, the list(s) of goods and services that DENC and PSNC each intend to take from the Service Company, the list(s) of goods and services DENC and PSNC intend to take from each other and the Utility Affiliates, and the basis for the determination of such list(s) and the elections of such services. All such lists that involve payment of fees or other compensation by DENC or PSNC shall require acceptance and authorization by the Commission, and shall be subject to any other Commission action required or authorized by North Carolina law and the Rules and orders of the Commission.

(b) DENC and PSNC shall take goods and services from an Affiliate only in accordance with the filed service agreements and approved list(s) of services. DENC and PSNC shall file notice with the Commission in Docket Nos. E-22, Sub 551A and G-5, Sub 585A, respectively, at least 15 days prior to making any proposed changes to the service agreements or to the lists of services.

4.5 Charges for and Allocations of the Costs of Affiliate Transactions. To the maximum extent practicable, all costs of Affiliate transactions shall be directly charged. When not practicable, such costs shall be assigned in proportion to the direct charges. If such costs are of a nature that direct charging and direct assignment are not practicable, they shall be allocated in accordance with Commission- approved allocation methods. The following additional provisions shall apply:

(a) DENC and PSNC shall keep on file with the Commission a cost allocation manual (CAM) with respect to goods or services provided by DENC or PSNC, any Utility Affiliate, the Service Company, any other Non-Utility Affiliate, Dominion Energy, any other Affiliates, or any Nonpublic Utility Operation to DENC or PSNC. PSNC will adopt DENC's CAM.

(b) The CAM shall describe how all directly charged, direct assignment, and other costs for each provider of goods and services will be charged between and among DENC, PSNC, their Utility Affiliates, Non-Utility Affiliates, Dominion Energy, any other Affiliates, and the Nonpublic Utility Operations, and shall include a detailed review of the common costs to be allocated and the allocation factors to be used.

(c) The CAM shall be updated annually, and the revised CAM shall be filed with the Commission no later than March 31 of the year that the CAM is to be in effect. DENC and PSNC shall review the appropriateness of the allocation bases every two years, and the results of such review shall be filed with the Commission. Interim changes shall be made to the CAM, if and when necessary, and shall be filed with the Commission, in accordance with Regulatory Condition 4.6.

(d) No changes shall be made to the procedures for direct charging, direct assigning, or allocating the costs of Affiliate transactions or to the method of accounting for such transactions associated with goods and services (including Shared Services provided by the Service Company) provided to or by Dominion Energy, other Affiliates, and the Nonpublic Utility Operations until DENC or PSNC has given

15 days' notice to the Commission of the proposed changes, in accordance with Regulatory Condition 4.6.

4.6 Procedures Regarding Interim Changes to the CAM or Lists of Goods and Services for which 15 Days' Notice is Required. With respect to interim changes to the CAM or changes to lists of goods and services, for which the 15 day notice to the Commission is required, the following procedures shall apply: the Public Staff shall file a response and make a recommendation as to how the Commission should proceed before the end of the notice period. If the Commission has not issued an order within 30 days of the end of the notice period, DENC or PSNC may proceed with the changes but shall be subject to any fully adjudicated Commission order on the matter. The provisions of Regulatory Condition 13.2 do not apply to advance notices filed pursuant to Regulatory Condition 4.5(c) and (d). Such advance notices shall be filed in Docket Nos. E-22, Sub 551A and G-5, Sub 585A.

4.7 Annual Reports of Affiliate Transactions. DENC and PSNC shall file annual report(s) of affiliated transactions with the Commission in a format to be prescribed by the Commission in Docket Nos. E-22, Sub 551A and G-5, Sub 585A. The report(s) shall be filed on or before May 30 of each year, for activity through December 31 of the preceding year. DENC, PSNC, and other parties may propose changes to the required affiliated transaction reporting requirements and submit them to the Commission for approval, also in Docket Nos. E-22, Sub 551A and G- 5, Sub 585A.

4.8 Ongoing Review by Commission.

(a) The services rendered by DENC and PSNC to their Affiliates and Nonpublic Utility Operations and the services received by DENC or PSNC from their Affiliates and Nonpublic Utility Operations pursuant to the filed service agreements, the costs and benefits assigned or allocated in connection with such services, and the determination or calculation of the bases and factors utilized to assign or allocate such costs and benefits, as well as DENC's and PSNC's compliance with the Commission-approved Code of Conduct and all Regulatory Conditions, shall remain subject to ongoing review. These agreements shall be subject to any Commission action required or authorized by North Carolina law and the Rules and orders of the Commission.

(b) The service agreements, the CAM and the assignments and allocations of costs pursuant thereto, the biannual allocation factor reviews required by Regulatory Condition 4.5(c), the list(s) and the goods and services provided pursuant thereto, and any changes to these documents shall be subject to ongoing Commission review, and Commission action if appropriate.

4.9 Future Orders. For the purposes of North Carolina retail accounting, reporting, and ratemaking, the Commission may, after appropriate notice and opportunity to be heard, issue future orders relating to DENC's or PSNC's cost of service as the Commission may determine are necessary to ensure that DENC's and PSNC's operations and transactions with their Affiliates and Nonpublic Utility Operations are consistent with the Regulatory Conditions and Code of Conduct, and with any other applicable decisions of the Commission.

4.10 Review by the FERC. Notwithstanding any of the provisions contained in these Regulatory Conditions, to the extent the allocations adopted by the Commission when compared to the allocations adopted by the other State commissions with ratemaking authority as to a Utility Affiliate of DENC or PSNC result in significant trapped costs related to "non-power goods or administrative or management services provided by an associate company organized specifically for the purpose of providing such goods or services to any public utility in the same holding company system," including DENC and PSNC, DENC or PSNC may request pursuant to Section 1275(b) of Subtitle F in Title XII of the Energy Policy Act of 2005 that the FERC "review and authorize the allocation of the costs for such goods and services to the extent relevant to that associate company." Such review and authorization shall have whatever effect it is determined to have under the law. The quoted language in this Regulatory Condition is taken directly from Section 1275(b) of Subtitle F in Title XII of the Energy Policy Act of 2005. The terms "associate company" and "holding company system" are defined in Sections 1262(2) and 1262(9), respectively, of Subtitle F in Title XII of the Energy Policy Act of 2005 and have the same meanings for purposes of this condition.

4.11 Biannual Review of Certain Transactions by Internal Auditors. At least biannually, Dominion Energy shall conduct an internal audit to review the affiliate transactions undertaken pursuant to Affiliate agreements filed in accordance with Regulatory Condition 4.4 and of DENC's compliance with all conditions approved by the Commission concerning Affiliate transactions, including the propriety of the transfer pricing of goods and services between or among DENC, PSNC, other Affiliates, and all of the Nonpublic Utility Operations. The first audit shall begin two years from the date of the close of the Merger. It shall include whether DENC's and PSNC's transactions, services, and other Affiliate dealings pursuant to the regulated utility-to-regulated utility service agreement and any other utility to utility agreements are consistent with all of the conditions related to affiliate dealings and the Code of Conduct and whether DENC and PSNC have operated in accordance with those conditions and Code of Conduct. The second audit shall begin two years from the date of the Commission's order on the internal auditor's final report on the first audit or, if no such order is issued, two years from the date of such final report. It shall include whether DENC's and PSNC's transactions, services, and other Affiliate dealings pursuant to the Service Company Utility Service Agreement and other Affiliate transactions other than transactions undertaken pursuant to regulated utility to regulated utility service agreements are consistent with all of the conditions related to affiliate dealings and the Code of Conduct and whether DENC and PSNC have operated in accordance with those conditions and Code of Conduct. Thereafter, internal audits shall occur every two years from the date of the Commission's order on the immediately preceding auditor's final report or, if no such order is issued, two years from the date of such final report. The subject matter of these audits shall alternate between the subject matters for the first and second internal audits. DENC and PSNC may request a change in the frequency of the audit reports in future years, subject to approval by the Commission. Such biannual reviews shall also address transactions between DENC or PSNC and Dominion Energy, other Affiliates, and the Nonpublic Utility Operations, transactions between DENC and PSNC, and other transactions between or among Affiliates if such transactions are reasonably likely to have a significant Effect on DENC's or PSNC's Rates or Service. To the extent external audits of the transactions are conducted, DENC and PSNC shall make available such audits for review by the Public Staff and the Commission. DENC and PSNC also shall make available for review by the Public Staff and the Commission all workpapers relating to internal audits and all other internal audit workpapers, if any, related to affiliate transactions, and shall not oppose Public Staff and Commission requests to review relevant external audit workpapers. Neither DENC, PSNC, Dominion Energy, any other Affiliate, nor any Nonpublic Utility Operation shall assert the attorney-client privilege for any internal audit report or workpaper, any portion of such report or workpaper, or any support requested by the Public Staff or Commission with regard to such report or workpaper, with regard to the internal audits required by this paragraph.

4.12 Notice of DENC, PSNC, Dominion Energy, and Service Company and Non-Utility Affiliates FERC Audits. At such time as DENC, PSNC, Dominion Energy, or the Service Company receives notice from the FERC related to an audit of any Affiliate of DENC or PSNC, DENC or PSNC shall promptly file a notice with the Commission that such an audit will be commencing. Any initial report of the FERC's audit team shall be provided to the Public Staff, and any final report shall be filed with the Commission in Docket Nos. E-22, Sub 551E and G-5, Sub 585E, respectively.

4.13 Acquisition Adjustment. Any acquisition adjustment that results from the Merger shall be excluded from DENC's and PSNC's utility accounts and treated for regulatory accounting, reporting, and ratemaking purposes so that it does not affect DENC's North Carolina retail rates and charges for Electric Services or PSNC's North Carolina rates and charges for Natural Gas Services.

4.14 Non-Consummation of Merger. If the Merger is not consummated, neither the cost, nor the receipt, of any termination payment between Dominion Energy and PSNC shall be allocated to DENC or PSNC or recorded on their books. DENC's Retail Native Load Customers or PSNC's Customers shall not otherwise bear any direct expenses or costs associated with a failed merger.

4.15 Protection from Commitments to Wholesale Customers.

(a) This Regulatory Condition does not apply to PSNC.

(b) For North Carolina retail electric cost of service/ratemaking purposes, DENC's electric system costs shall be assigned or allocated between and among retail and wholesale jurisdictions based on reasonable and appropriate cost causation principles, taking into consideration the Commission's findings and conclusions regarding the costs associated with DENC's membership in PJM, Inc., set forth in the Commission's Dec. 22, 2016, order issued in Docket No. E-22, Sub 532. For cost of service/ratemaking purposes, North Carolina retail ratepayers shall be held harmless from any cost assignment or allocation of costs resulting from agreements between DENC and any of its wholesale customers, other than for reasonable and appropriate load decline or growth.

(c) To the extent that commitments are made by or imposed upon DENC, PSNC, Dominion Energy, another Affiliate, or a Nonpublic Utility Operation relating to the Merger, either through an offer, a settlement, or as a result of a regulatory order, the effects of which serve to increase the North Carolina retail cost of service or

North Carolina retail fuel costs under reasonable cost allocation practices, or decrease the bulk power revenues that are assigned or allocated to DENC's North Carolina retail operations or credited to DENC's jurisdictional fuel expenses, the effects of these commitments shall not be recognized for North Carolina retail ratemaking purposes.

4.16 Joint Owner-Specific Issues. Assignment or allocation of costs to the North Carolina retail jurisdiction shall not be adversely affected by the manner and amount of recovery of electric system costs from the Joint Owners as a result of agreements between DENC and the Joint Owners. This Regulatory Condition does not apply to PSNC.

4.17 Inclusion of Cost Savings in Future Rate Proceedings. Neither DENC, PSNC, Dominion Energy, any other Affiliate, nor a Nonpublic Utility Operation shall assert that any interested party is prohibited from seeking the inclusion in future rate proceedings of cost savings that may be realized as a result of any business combination transaction impacting DENC and PSNC.

4.18 Reporting of Merger-Related Expenses. The North Carolina portion of Merger- Related Expenses shall be reflected in DENC's North Carolina ES-1 Reports and PSNC's North Carolina GS-1 Reports, as recorded on their books and records under generally accepted accounting principles. DENC and PSNC shall include as a footnote in their ES-1 and GS-1 Reports, as applicable, the Merger- Related Expenses that were expensed during the relevant period.

4.19 Liabilities of CNG and SCE&G. DENC's Retail Native Load Customers and PSNC's Customers shall be held harmless from all liabilities of CNG and SCE&G and their subsidiaries, including those incurred prior to and after Dominion Energy's acquisition of CNG in 1999. These liabilities include, but are not limited to, those associated with the following: (i) manufactured gas plant sites, (ii) asbestos claims, (iii) environmental compliance, (iv) pensions and other employee benefits, (v) decommissioning costs, and (vi) taxes. DENC's Retail Native Load Customers and PSNC's Customers shall also be held harmless from all liabilities of SCE&G, including all liabilities associated with the Summer Nuclear Station.

4.20 Hold Harmless Commitment. PSNC's Customers shall be held harmless from all current and prospective liabilities of DENC. DENC's Customers shall be held harmless from all current and prospective liabilities of PSNC. DENC, PSNC, Dominion Energy, the other Affiliates, and all of the Nonpublic Utility Operations shall take all such actions as may be reasonably necessary and appropriate to hold North Carolina Customers harmless from the effects of the Merger, including rate increases or foregone opportunities for rate decreases, and other effects otherwise adversely impacting Customers.

Cost of Service Manual. Within six months after the closing date of the Merger, DENC shall file with the Commission revisions to its electric cost of service manual to reflect any changes to the cost of service determination process made necessary by the Merger, any subsequent alterations in the organizational structure of DENC, PSNC, Dominion Energy, other Affiliates, or the Nonpublic Utility Operations, or other circumstances that necessitate such changes. These filings shall be made in Docket No. E-22, Sub 551A.

SECTION V
CODE OF CONDUCT

These Regulatory Conditions include a Code of Conduct. The Code of Conduct governs the relationships, activities, and transactions between or among the public utility operations of DENC, PSNC, Dominion Energy, the Affiliates of DENC and PSNC, and the Nonpublic Utility Operations of DENC and PSNC.

5.1 Compliance. DENC, PSNC, Dominion 'Energy, the other Affiliates, and the Nonpublic Utility Operations shall be bound by the terms of the Code of Conduct set forth in Appendix A and as it may subsequently be amended.

SECTION VI
PJM CONDITIONS

6.1 Cost-based Rates. DENC's North Carolina retail Customers will continue to be entitled to, and receive, cost-based rates for generation, transmission, and distribution (including any ancillary services) determined pursuant to North Carolina law notwithstanding DENC's integration into PJM or decision to participate in any capacity or energy market administered by PJM.

6.2 Reporting Requirements. DENC shall continue to comply with the reporting obligations established in Paragraph 5[1] of the Joint Offer of Settlement entered into between DENC and PJM filed in Docket No. E-22, Sub 418, on December 6, 2004, as set forth below.

Condition 5:

Dominion agrees to submit annually to the Commission, [on or before August 31 of each year,] a report or reports that provide the following information set forth in items a. through d. below. [The annual report or

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[1] Pursuant to the letter filed by Monitoring Analytics, LLC in Docket No. E-22, Sub 532 on Nov. 16, 2016, Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor ("IMM") for PJM, will continue to annually file the information specified in Paragraph 6 of the December 16, 2004 Joint Offer of Settlement. Paragraph 6 provides:

6. [The PJM IMM] will provide annual reports to the Commission [on or before July 15 of each year,] detailing the following information:

a. A description of transmission constraints impacting Dominion's service territory within North Carolina and the events leading up to such constraints. Such description should include an estimate of the congestion costs associated with each event.
b. The actual locational marginal prices by bus impacting Dominion's service territory within North Carolina, including a separate identification of the congestion component of such prices.
c. Such reports will be provided annually [original language inapplicable].

reports] will cover the twelve month period June 1 through the following May 31, to correspond with PJM's FTR allocation and auction schedule:

a. A summary of monthly congestion costs and FTR revenues allocated to the North Carolina portion of the Company's service territory, including a description of the method of allocating such costs and revenues. This summary should provide a breakdown of explicit congestion costs (incurred through transmission congestion charges) and discuss the extent to which explicit congestion costs are mitigated through the receipt of FTR or ARR revenue.

b. A summary of the Company's monthly capacity and energy transactions with the PJM markets to the extent they impact costs and revenues allocated to the North Carolina portion of the Company's service territory.

c. A narrative description of the LMP load aggregation zones designated within the North Carolina portion of the Company's service territory. This description should describe any change (actual or proposed) in the designation of such zones and the cause of any such change.

d. A narrative description of the Company's general approach for requesting or obtaining ARRs or FTRs, the level of ARRs or FTRs requested, and the amount received that impacts the Company's operations in North Carolina. This description should describe any change (actual or proposed) in the allocation of ARRs or FTRs to the Company and the cause of any such change.

SECTION VII
FINANCINGS

The following Regulatory Conditions are intended to ensure (a) that DENC's and PSNC's capital structures and cost of capital are not adversely affected through their affiliation with Dominion Energy, each other, and other Affiliates and (b) that DENC and PSNC have 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.

These conditions do not supersede any orders or directives of the Commission regarding specific securities issuances by DENC, PSNC, or Dominion Energy. The approval of the Merger by the Commission does not restrict the Commission's right to review, and by order to adjust, DENC's or PSNC's cost of capital for ratemaking purposes for the effect(s) of the securities-related transactions associated with the Merger.

7.1 Accounting for Equity Investment in Subsidiaries. Dominion Energy shall maintain its books and records so that any net equity investment in CNG or SCANA, their subsidiaries, or their successors, by Dominion Energy or any Affiliates can be identified and made available on an ongoing basis. This information shall be provided to the Public Staff upon its request.

7.2 Accounting for Capital Structure Components and Cost Rates. Dominion Energy, DENC, and PSNC shall keep their respective accounting books and records in a manner that will allow all capital structure components and cost rates of the cost of capital to be identified easily and clearly for each entity on a separate basis. This information shall be provided to the Public Staff upon its request.

7.3 Accounting for Equity Investment in DENC and PSNC. DENC and PSNC shall keep their respective accounting books and records so that the amount of Dominion Energy's equity investment in DENC and PSNC can be identified and made available upon request on an ongoing basis. This information shall be provided to the Public Staff upon request.

7.4 Reporting of Capital Contributions. As part of their Commission ES-1 and GS-1 Reports, DENC and PSNC shall include a schedule of any capital contribution(s) received from Dominion Energy in the applicable calendar quarter.

7.5 Identification of Long-term Debt Issued by DENC and PSNC. DENC and PSNC shall each identify as clearly as possible long-term debt (of more than one year's duration) that they issue in connection with their regulated utility operations and capital requirements or to replace existing debt.

7.6 Procedures Regarding Proposed Financings.

(a) The issuance of securities by Dominion Energy, DENC, or PSNC after the announcement of the Merger does not restrict the Commission's authority to review and, if required in order to establish just and reasonable rates, adjust the cost of capital of Dominion Energy, DENC, or PSNC, as the case may be, for ratemaking purposes.

(b) For all types of financings for which PSNC (or its subsidiaries) are the issuers of the respective securities, PSNC (or its subsidiaries) shall request approval from the Commission to the extent required by G.S. 62-160 through G.S. 62-169 and Commission Rule R1-16. Generally, the format of these filings should be consistent with past practices. A "shelf registration" approach (similar to Docket No. E-7, Sub 727) may be requested.

(c) Securities issuances or financings that are associated with a merger, acquisition, or other business combination shall be filed in conjunction with the information requirements and deadlines stated in Regulatory Conditions 9.1 and 9.2, and this Condition 7.6 shall not apply to such securities issuances or financings.

7.7 Intercompany Revolving Line of Credit (Loan) Agreement Subject to the limitations imposed in Regulatory Condition 8.6, DENC and PSNC may borrow through Dominion Energy. Dominion Energy intends to have in place a one-way Intercompany Revolving Credit Agreement ("IRCA") that allows PSNC to borrow directly from Dominion Energy but does not allow for Dominion Energy (or Affiliates) to borrow from PSNC. Funds under the IRCA will be available on a daily basis, as needed. PSNC will file monthly reports on its participation in the Intercompany Revolving Line of Credit (Loan) Agreement.

7.8 Borrowing Arrangements. Subject to the limitations imposed in Regulatory Condition 8.6, DENC may borrow short-term funds through one or more joint external debt or credit arrangements (a Credit Facility), provided that the following conditions are met:

(a) No borrowing by DENC under a Credit Facility shall exceed one year in duration, absent Commission approval;
(b) No Credit Facility shall include, as a borrower, any party other than DENC; and
(c) DENC's participation in any Credit Facility shall in no way cause it to guarantee, assume liability for, or provide collateral for any debt or credit other than its own.
(d) Should PSNC decide in the future to seek short-term financing via sources other than those permitted pursuant to Section 7.7, it will not do so without first notifying the Commission. PSNC will file monthly reports on any such short-term borrowings.

7.9 Long-Term Debt Fund Restrictions. DENC and PSNC shall acquire their respective long-term debt funds through the financial markets, and shall neither borrow from, nor lend to, on a long-term basis, Dominion Energy or any of the other Affiliates. To the extent that either DENC or PSNC borrows on short-term or long- term bases in the financial markets and is able to obtain a debt rating its debt shall be rated under its own name.

SECTION VIII
CORPORATE GOVERNANCE/RING FENCING

The following Regulatory Conditions are intended to ensure the continued viability of DENC and PSNC and to insulate and protect DENC, PSNC, and DENC's Retail Native Load Customers and PSNC's Customers from the business and financial risks of Dominion Energy and the Affiliates within the Dominion Energy holding company system, including the protection of utility assets from liabilities of Affiliates.

8.1 Investment Grade Debt Rating. DENC and PSNC shall manage their respective businesses so as to maintain an investment grade debt rating on all of their rated debt issuances with all of the debt rating agencies. If Dominion Energy's or PSNC's debt rating falls within one notch of an investment grade rating by S&P and Moody; then, DENC and PSNC shall file written notice to the Commission and the Public Staff within five (5) days of such change and an explanation as to why the downgrade occurred. Within 45 days of such notice, DENC or PSNC shall provide the Commission and the Public Staff with a specific plan for maintaining and improving its debt rating. The Commission, after notice and hearing, may then take whatever action it deems necessary consistent with North Carolina law to protect the interests of DENC's Retail Native Load Customers and PSNC's Customers in the continuation of adequate and reliable service at just and reasonable rates.

8.2 Protection Against Debt Downgrade. To the extent the cost rates of any of DENC's or PSNC's long-term debt (more than one year) or short-term debt (one year or less) are adversely affected after closing of the Merger through a ratings downgrade of those entities attributable to the Merger, a replacement cost rate to remove the effect shall be used for all purposes affecting any of DENC's North Carolina retail rates and charges and

PSNC's North Carolina rates and charges. This replacement cost rate shall be applicable to all financings, refundings, and refinancings taking place following an adverse change in ratings attributed to the Merger, and shall reflect the cost rate that is comparable to an issuer credit rating of a "BBB+" rating by S&P and an "A2" rating by Moody's. If a downgrade has occurred and is continuing, a replacement cost calculation will be determined, as part of DENC's and PSNC's future general rate cases. This procedure shall be effective for five years following the merger. This Regulatory Condition does not indicate a preference for a specific debt rating or preferred stock rating for DENC or PSNC on current or prospective bases.

8.3 Distributions from DENC and PSNC to Holding Company. DENC and PSNC shall limit cumulative distributions paid to Dominion Energy subsequent to the Merger to (a) the amount of Retained Earnings on the day prior to the closure of the Merger, plus (b) any future earnings recorded by DENC and PSNC subsequent to the Merger. DENC and PSNC shall notify the Commission and Public Staff if the payment of any distributions or dividends results in DENC's and PSNC's actual common equity component of total capitalization falling below 45%, using the method of calculating equity levels under the ratemaking precedents of this Commission. The notification shall include a brief explanation and planned steps to remedy the balance of common equity.

8.4 Debt Ratio Restrictions. To the extent any of Dominion Energy's external debt or credit arrangements contain covenants restricting the ratio of debt to total capitalization on a consolidated basis to a maximum percentage of debt, Dominion Energy shall ensure that the capital structures of both DENC and PSNC individually meet those restrictions.

8.5 Dominion Energy, Inc. commits to use commercially reasonable efforts to maintain a "BBB+" issuer credit rating by S&P and an "A2" rating by Moody's for PSNC and DENC.

8.6 Limitation on Continued Participation in Credit Arrangements with Affiliates. DENC and PSNC may participate in any authorized joint debt or credit arrangement as provided in Regulatory Conditions 7.7 and 7.8 only to the extent such participation is beneficial to DENC's respective Retail Native Load Customers and PSNC's Customers and does not negatively affect DENC's, or PSNC's ability to continue to provide adequate and reliable service at just and reasonable rates.

8.7 Notice of Level of Non-Utility Investment by Holding Company. In order to enable the Commission to determine whether the cumulative investment by Dominion Energy in assets, ventures, or entities other than regulated utilities is reasonably likely to have an Effect on DENC's or PSNC's Rates or Service so as to warrant Commission action (pursuant to Regulatory Condition 8.8 or other applicable authority) to protect DENC's Retail Native Load Customers or PSNC's Customers, Dominion Energy shall notify the Commission within 90 days following the end of any fiscal year for which Dominion Energy reports to the Securities and Exchange Commission assets in its operations other than regulated entities that are in excess of 22% of its consolidated total assets. The following procedures shall apply to such a notice:

(a) Any interested party may file comments within 45 days of the filing of Dominion Energy's notice.

(b) If timely comments are filed, the Public Staff shall place the matter on a Commission Staff Conference agenda as soon as possible, but in no event later than 15 days after the comments are filed, and shall make a recommendation as to how the Commission should proceed. If the Commission determines that the percentage of total assets invested in Dominion Energy's operations other than regulated entities is reasonably likely to have an Effect on DENC's or PSNC's Rates or Service so as to warrant action by the Commission to protect DENC's Retail Native Load Customers and PSNC's Customers, the Commission shall issue an order setting the matter for further consideration. If the Commission determines that the percentage threshold being exceeded does not warrant action by the Commission, the Commission shall issue an order so ruling.

8.8 Use of nuclear decommissioning funds. DENC's nuclear decommissioning funds shall not be used in full or in part for the purpose of the Merger or any other purpose other than providing financial assurance for decommissioning the Surry and North Anna nuclear power stations owned by DENC.

8.9 Notice by Holding Company of Certain Investments. Dominion Energy shall file a notice with the Commission subsequent to Board approval and as soon as practicable following any public announcement of any investment in a regulated utility or a non-regulated business that represents five (5) percent or more of Dominion Energy's book capitalization.

8.10 Ongoing Review of Effect of Holding Company Structure. The operation of DENC and PSNC under a holding company structure shall continue to be subject to Commission review. To the extent the Commission has authority under North Carolina law, it may order modifications to the structure or operations of Dominion Energy, the Service Company, another Affiliate, or a Nonpublic Utility Operation, and may take whatever action it deems necessary in the interest of DENC's Retail Native Load Customers and PSNC's Customers to protect the economic viability of DENC and PSNC, including the protection of DENC's and PSNC's public utility assets from liabilities of Affiliates.

8.11 Investment by DENC or PSNC in Non-regulated Utility Assets and Non-utility Business Ventures. Neither DENC nor PSNC shall invest in a non-regulated utility asset or any non-utility business venture exceeding $50 million in purchase price or gross book value to DENC or PSNC unless it provides 30 days' advance notice. Regulatory Condition 13.2 shall apply to an advance notice filed pursuant to this Regulatory Condition. Purchases of assets, including land that will be held with a definite plan for future use in providing Electric Services in DENC's franchise area or Natural Gas Services in PSNC's franchise area, shall be excluded from this advance notice requirement.

8.12 Investment by Holding Company in Exempt Wholesale Generators. By April 15 of each year, Dominion Energy shall provide to the Commission and the Public Staff a report summarizing Dominion Energy's investment in exempt wholesale generators (EWGs) and foreign utility companies (FUCOs) in relation to its level of consolidated retained earnings and consolidated total capitalization at the end of the preceding year. Exempt wholesale generator and foreign utility company are defined in Section 1262(6) of Subtitle F in Title XII of the Energy Policy Act of 2005 and have the same meanings for purposes of this condition.

8.13 Notice by DENC or PSNC of Default or Bankruptcy of Affiliate. If an Affiliate of DENC or PSNC experiences a default on an obligation that is material to Dominion Energy or files for bankruptcy, and such bankruptcy is material to Dominion Energy, DENC, or PSNC, DENC and PSNC shall notify the Commission in advance, if possible, or as soon as possible, but not later than ten days from such event.

8.14 Annual Report on Corporate Governance. No later than March 31 of each year, DENC and PSNC shall file a report including the following:

(a) A complete, detailed organizational chart (i) identifying DENC, PSNC, and each Dominion Energy financial reporting segment, and (ii) stating the business purpose of each Dominion Energy financial reporting segment. Changes from the report for the immediately preceding year shall be summarized at the beginning of the report.

(b) A list of all Dominion Energy financial reporting segments that are considered to constitute non-regulated investments and a statement of each segment's total capitalization and the percentage it represents of Dominion Energy's non-regulated investments and total investments. Changes from the report for the immediately preceding year shall be summarized at the beginning of the report.

(c) An assessment of the risks that each unregulated Dominion Energy financial reporting segment could pose to DENC or PSNC based upon current business activities of those affiliates and any contemplated significant changes to those activities.

(d) A description of DENC's, PSNC's and each significant Affiliate's actual capital structure.

(e) A list of all protective measures (other than those provided for by these Regulatory Conditions) in effect between DENC, PSNC, and any of their Affiliates, and a description of the goal of each measure and how it achieves that goal, such as mitigation of DENC's and PSNC's exposure in the event of a bankruptcy proceeding involving any Affiliate(s).

(f) A list of corporate executive officers and other key personnel that are shared between DENC and PSNC, and any Affiliate, along with a description of each person's position(s) with, and duties and responsibilities to each entity.

(g) A calculation of Dominion Energy's total book and market capitalization as of December 31 of the preceding year for common equity, preferred stock, and debt.

SECTION IX
FUTURE MERGERS AND ACQUISITIONS

The following Regulatory Conditions are intended to ensure that the Commission receives sufficient notice to exercise its lawful authority over proposed mergers, acquisitions, and other business combinations involving Dominion Energy, DENC, PSNC, other Affiliates, or the

Nonpublic Utility Operations. The advance notice provisions set forth in Regulatory Condition 13.2 do not apply to these conditions.

9.1 Mergers and Acquisitions by or Affecting DENC or PSNC. For any proposed merger, acquisition, or other business combination by DENC or PSNC that would have an Effect on DENC or PSNC's Rates or Service, DENC, or PSNC shall file in a new Sub docket an application for approval pursuant to G S. 62 - 111(a) at least 180 days before the proposed closing date for such merger, acquisition, or other business combination.

9.2 Mergers and Acquisitions Believed Not to Have an Effect on DENC's, or PSNC's Rates or Service. For any proposed merger, acquisition, or other business combination that is believed not to have an Effect on DENC's, or PSNC's Rates or Service, but which involves Dominion Energy, other Affiliates, or the Nonpublic Utility Operations and which has a transaction value exceeding $1.5 billion, the following shall apply:

(a) Advance notification shall be filed with the Commission in a new Sub docket by the merging entities at least 90 days prior to the proposed closing date for such proposed merger, acquisition or other business combination. The advance notification is intended to provide the Commission an opportunity to determine whether the proposed merger, acquisition, or other business combination is reasonably likely to affect DENC or PSNC so as to require approval pursuant to G S. 62-111(a). The notification shall contain sufficient information to enable the Commission to make such a determination. If the Commission determines that such approval is required, the 180-day advance filing requirement in Regulatory Condition 9.1 shall not apply.

(b) Any interested party may file comments within 45 days of the filing of the advance notification.

(c) If timely comments are filed, the Public Staff shall place the matter on a Commission Staff Conference agenda as soon as possible, but in no event later than 15 days after the comments are filed, and shall recommend that the Commission issue an order deciding how to proceed. If the Commission determines that the merger, acquisition, or other business combination requires approval pursuant to G.S. 62-111(a), the Commission shall issue an order requiring the filing of an application, and no closing can occur until and unless the Commission approves the proposed merger, acquisition, or business combination. If the Commission determines that the merger, acquisition, or other business combination does not require approval pursuant to G.S. 62-111(a), the Commission shall issue an order so ruling. At the end of the notice period, if no order has been issued, Dominion Energy, any other Affiliate, or the Nonpublic Utility Operation may proceed with the merger, acquisition, or other business combination but shall be subject to any fully-adjudicated Commission order on the matter.

ELECTRIC – MERGER

SECTION X
STRUCTURE/ORGANIZATION

The following Regulatory Conditions are intended to ensure that the Commission receives adequate notice of, and opportunity to review and take such lawful action as is necessary and appropriate with respect to, changes to the structure and organization of Dominion Energy, DENC, PSNC, and other Affiliates, and Nonpublic Utility operations as they may affect Customers.

10.1 Transfer of Services, Functions, Departments, Rights, Assets, or Liabilities. DENC and PSNC shall file notice with the Commission 30 days prior to the initial transfer or any subsequent transfer of any services, functions, departments, rights, obligations, assets, or liabilities from DENC or PSNC to the Service Company that involves services, functions, departments, rights, obligations, assets, or liabilities other than those of a governance or corporate type nature that traditionally have been provided by a service company or (b) potentially would have a significant effect on DENC's or PSNC's public utility operations. The provisions of Regulatory Condition 13.2 apply to an advance notice filed pursuant to this Regulatory Condition.

10.2 Notice and Consultation with Public Staff Regarding Proposed Structural and Organizational Changes. Upon request, DENC and PSNC shall meet and consult with, and provide requested relevant data to, the Public Staff regarding plans for significant changes in DENC's, PSNC's, or Dominion Energy's organization, structure (including RTO developments), and activities; the expected or potential impact of such changes on Customer rates, operations, and service; and proposals for assuring that such plans do not adversely affect DENC's Retail Native Load Customers or PSNC's Customers. To the extent that proposed significant changes are planned for the organization, structure, or activities of an Affiliate or Nonpublic Utility Operation and such proposed changes are likely to have an adverse impact on DENC's Retail Native Load Customers or PSNC's Customers, then DENC's and PSNC's plans and proposals for assuring that those plans do not adversely affect their Customers must be included in these meetings. DENC and PSNC shall inform the Public Staff promptly of any such events and changes.

SECTION XI
SERVICE QUALITY

The following Regulatory Conditions are intended to ensure that DENC and PSNC continue to implement and further their commitment to providing superior public utility service by meeting recognized service quality indices and implementing industry best practices of each other and their Utility Affiliates, to the extent reasonably practicable.

11.1 Overall Service Quality. Upon consummation of the Merger, DENC and PSNC each shall continue their commitment to providing superior public utility service and shall maintain the overall reliability of Electric Services and Natural Gas Services at levels no less than the overall levels it has achieved in the past decade.

11.2 Superior bundled retail electric service. DENC will continue to take all reasonable and prudent actions necessary to continue to provide its North Carolina retail customers with superior bundled retail electric service including but not limited to: reliable generation, transmission, and distribution service; minimization of power outages; efficient restoration of service; and responsive customer service.

11.3 Best Practices. DENC and PSNC shall make every reasonable effort to incorporate each other's industry best practices into its own practices to the extent reasonably practicable.

11.4 Quarterly Reliability Reports. DENC shall provide quarterly service reliability reports to the Public Staff on the following measures: System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI).

11.5 Notice of NERC Audit. At such time as DENC receives notice that the North American Electric Reliability Corporation (NERC) or the SERC Reliability Corporation will be conducting a non-routine compliance audit with respect to DENC's compliance with mandatory reliability standards, DENC shall notify the Public Staff.

11.6 Right-of-Way Maintenance Expenditures (DENC). DENC shall budget and expend sufficient funds to trim and maintain its lower voltage line rights-of-way and its distribution rights-of-way in a manner consistent with its internal right-of-way clearance practices and Commission Rule R8-26. In addition, DENC shall track annually, on a major category basis, departmental or division budget requests, approved budgets, and actual expenditures for right-of-way maintenance.

11.7 Right-of-Way Maintenance Expenditures (PSNC). PSNC shall budget and expend sufficient funds to maintain its pipeline rights-of-way so as to allow ready access by personnel and vehicles for the purpose of responding to pipeline damage, conducting leak and corrosion surveys, performing maintenance activities, and ensuring system integrity, safety, and reliability.

11.8 Right-of-Way Clearance Practices (DENC). DENC shall provide a copy of its internal right-of-way clearance practices to the Public Staff, and shall promptly notify the Public Staff of any significant changes or modifications to the practices or maintenance schedules.

11.9 Right-of-Way Clearance Practices (PSNC). PSNC shall provide a copy of its Operating and Maintenance Manual to the Public Staff and shall promptly notify the Public Staff in writing of any substantive changes to the practices or maintenance schedules.

11.10 Meetings with Public Staff.

(a) DENC and PSNC shall each meet annually with the Public Staff to discuss service quality initiatives and results, including (i) ways to monitor and improve service quality, (ii) right-of-way maintenance practices, budgets, and actual expenditures, and (iii) plans that could have an effect on customer service, such as changes to call center operations.

(b) DENC and PSNC shall each meet with the Public Staff at least annually to discuss potential new tariffs, programs, and services that enable its customers to appropriately manage their energy bills based on the varied needs of their customers.

(c) DENC also commits to provide such other data as required by the Commission and/or the Public Staff, including information on transmission and generation reliability. DENC will meet with the Public Staff every six months to review such reports and other operational information.

11.11 Customer Access to Service Representatives and Other Services. DENC and PSNC shall continue to have knowledgeable and experienced customer service representatives available 24 hours a day to respond to service outage calls and during normal business hours to handle all types of customer inquiries. DENC and PSNC shall also maintain up-to-date and user-friendly online services and automated telephone service 24 hours a day to perform routine customer interactions and to provide general billing and customer information.

11.12 Customer Surveys. DENC and PSNC shall continue to survey their Customers regarding their satisfaction with public utility service and shall incorporate this information into their processes, programs, and services.

SECTION XII
TAX MATTERS

The following Regulatory Conditions are intended to ensure that DENC's Retail Native Load Customers and PSNC's North Carolina Customers do not bear any additional income taxes as a result of the Merger and receive an appropriate share of any income tax benefits associated with the service company Affiliates.

12.1 Costs Under Tax Sharing Agreements. Under any tax sharing agreement, DENC and PSNC shall not seek to recover from North Carolina Customers any taxes that exceed DENC's or PSNC's tax liability calculated as if it were a stand-alone, taxable entity for tax purposes.

12.2 Taxes Associated with Service Companies. The appropriate portion of any taxes or tax benefits associated with the Service Company shall accrue to the North Carolina retail operations of DENC and PSNC for regulatory accounting, reporting, and ratemaking purposes.

SECTION XIII
PROCEDURES

The following Regulatory Conditions are intended to apply to all filings made pursuant to these Regulatory Conditions unless otherwise expressly provided by, Commission order, rule, or statute.

13.1 Filings that Do Not Involve Advance Notice. Regulatory Condition filings that are not subject to Regulatory Condition 13.2 shall be made in sub-dockets of Docket Nos. E-22, Sub 551 and G-5, Sub 585, as follows:

(a) Filings related to affiliate matters required by Regulatory Conditions 4.3, 4.4, 4.5, 4.6, 4.7, and 4.21, and Sections III.B.11 and III.D.8 of the Code of Conduct, shall be made by DENC and PSNC in Subs 551A and 585A, respectively;
(b) Filings related to financings required by Regulatory Condition 7.7 and 7.8, and the filings required by Regulatory Conditions 8.1, 8.3, 8.7, 8.9, 8.12, 8.13, and 8.14, shall be made by DENC and PSNC in Subs 551B and 585B, respectively;
(c) Filings related to compliance as required by Regulatory Condition 14.4 and filings required by Sections III.A.2(k), III.A.3(e), III.A.3(f), and III.D.5 of the Code of Conduct shall be made by DENC and PSNC in Subs 551C and 585C, respectively;
(d) Filings related to orders and filings with the FERC, as required by Regulatory Condition 3.9 and Section III.A.3(g) of the Code of Conduct shall be made by DENC and PSNC in Subs 551D and 585D, respectively.
(e) Filings related to notices from the FERC of audits of any Affiliate of DENC or PSNC, as required by Regulatory Condition 4.12, shall be made by DENC and PSNC in Subs 551E and 585E, respectively.

13.2 Advance Notice Filings. Advance notices filed pursuant to Regulatory Conditions 3.3(b), 8.11, and 10.1 shall be assigned a new, separate Sub docket. Such a filing shall identify the condition and notice period involved and state whether other regulatory approvals are required and shall be in the format of a pleading, with a caption, a title, allegations of the activities to be undertaken, and a verification. Advance notices may be filed under seal if necessary. The following additional procedures apply:

(a) Advance notices of activities to be undertaken shall not be filed until sufficient details have been decided upon to allow for meaningful discovery as to the proposed activities.
(b) The Chief Clerk shall distribute a copy of advance notice filings to each Commissioner and to appropriate members of the Commission Staff and Public Staff.
(c) DENC or PSNC shall serve such advance notices on each party to Docket Nos. E-22, Sub 551 and G-5, Sub 585, respectively, that has filed a request to receive them with the Commission within 30 days of the issuance of an order approving the Merger in this docket. These parties may participate in the advance notice proceedings without petitioning to intervene. Other interested persons shall be required to follow the Commission's usual intervention procedures.
(d) To effectuate this Regulatory Condition, DENC or PSNC shall serve pertinent information on all parties at the time it serves the advance notice. During the advance notice period, a free exchange of information is encouraged, and parties may request additional relevant information. If DENC or PSNC objects to a discovery request, DENC or PSNC and the requesting party shall try to resolve the matter. If the parties are unable to resolve the matter, DENC or PSNC may file a motion for a protective order with the Commission.

(e) The Public Staff shall investigate and file a response with the Commission no later than 15 days before the notice period expires. Any other interested party may also file a response or objection within 15 days before the notice period expires. DENC or PSNC may file a reply to the response(s).

(f) The basis for any objection to the activities to be undertaken shall be stated with specificity. The objection shall allege grounds for a hearing, if such is desired.

(g) If neither the Public Staff nor any other party files an objection to the activities within 15 days before the notice period expires, no Commission order shall be issued, and the Sub docket in which the advance notice was filed may be closed.

(h) If the Public Staff or any other party files a timely objection to the activities to be undertaken by DENC or PSNC, the Public Staff shall place the matter on a Commission Staff Conference agenda as soon as possible, but in no event later than two weeks after the objection is filed, and shall recommend that the Commission issue an order deciding how to proceed as to the objection. The Commission reserves the right to extend an advance notice period by order should the Commission need additional time to deliberate or investigate any issue. At the end of the notice period, if no objection has been filed by the Public Staff and no order, whether procedural or substantive, has been issued, DENC, PSNC, Dominion Energy, any other Affiliate, or the Nonpublic Utility Operation may execute the proposed agreement, proceed with the activity to be undertaken, or both, but shall be subject to any fully-adjudicated Commission order on the matter.

(i) If the Commission schedules a hearing on an objection, the party filing the objection shall bear the burden of proof at the hearing.

(j) The precedential effect of advance notice proceedings, like most issues of res judicata, will be decided on a fact-specific basis.

(k) If some other Commission filing or Commission approval is required by statute, notice pursuant to a Regulatory Condition alone does not satisfy the statutory requirement.

SECTION XIV
COMPLIANCE WITH CONDITIONS AND CODE OF CONDUCT

The following Regulatory Conditions are intended to ensure that Dominion Energy, DENC, PSNC, and all other Affiliates establish and maintain the structures and processes necessary to fulfill the commitments expressed in all of the Regulatory Conditions and the Code of Conduct in a timely, consistent, and effective manner.

14.1 Ensuring Compliance with Regulatory Conditions and Code of Conduct. Dominion Energy, DENC, PSNC, and all other Affiliates shall devote sufficient resources into the creation, monitoring, and ongoing improvement of effective internal compliance programs to ensure compliance with all Regulatory Conditions and the Code of Conduct, and shall take a proactive approach toward correcting any violations and reporting them to the Commission. This effort shall include the implementation of systems and protocols for monitoring, identifying, and correcting possible violations, a management culture that encourages compliance among all personnel, and the tools and training sufficient to enable employees to comply with Commission requirements.

14.2 Designation of Chief Compliance Officer. DENC and PSNC shall designate a chief compliance officer who will be responsible for compliance with the Regulatory Conditions and Code of Conduct. This person's name and contact information must be posted on DENC's and PSNC's Internet Websites.

14.3 Annual Training. DENC and PSNC shall implement within one (1) year of the closing of the Merger an annual training program on the requirements and standards contained within the Regulatory Conditions and Code of Conduct to all of their employees (including service company employees) whose duties in any way may be affected by such requirements and standards. New employees must receive such training within the first 60 days of their employment. Each employee who has taken the training must certify electronically or in writing that s/he has completed the training.

14.4 Report of Violations. If DENC or PSNC discover that a violation of their requirements or standards contained within the Regulatory Conditions and Code of Conduct has occurred then DENC or PSNC shall file a statement with the Commission in Docket Nos. E-22, Sub 551C and G-5, Sub 585C, respectively, describing the circumstances leading to that violation of DENC's or PSNC's requirements or standards, as contained within the Regulatory Conditions and Code of Conduct, and the mitigating and other steps taken to address the current or any future potential violation.

SECTION XV
PROCEDURES FOR DETERMINING LONG-TERM SOURCES OF PIPELINE CAPACITY AND SUPPLY

The following Regulatory Conditions are intended to ensure the continued practices of DENC and PSNC for determining long-term sources of pipeline capacity and supply.

15.1 Cost-benefit Analysis. The appropriate source(s) for the interstate pipeline capacity and supply shall be determined by DENC on the basis of the benefits and costs of such source(s) specific to its electric customers. The appropriate source(s) for the interstate pipeline capacity and supply shall be determined by PSNC on the basis of the specific benefits and costs of such source(s) specific to its natural gas customers, including electric power generating customers. PSNC shall not contract with an Affiliate interstate pipeline for additional capacity with a contractual term of ten years or more unless or until it has issued a request for proposals to obtain such capacity and considers the proposals in good faith. PSNC shall not contract with an Affiliate interstate pipeline for additional capacity with a contractual term of ten years or more unless the Affiliate is the least cost provider of such capacity or unless otherwise approved by the Commission.

15.2 Ownership and Control of Contracts. Except as provided in Code of Conduct Section III.D.5 (Joint purchases), PSNC shall retain title, ownership, and management of all gas contracts necessary to ensure the provision of reliable Natural Gas Services consistent with PSNC's best cost gas and capacity procurement methodology.

ELECTRIC – MERGER

SECTION XVI
RATE REDUCTION, MOST FAVORED NATION CLAUSE, AND OTHER RATEPAYER PROTECTION MATTERS

The following Regulatory Conditions are intended to ensure, through rate and other protections for PSNC's North Carolina retail ratepayers, that the benefits of the Merger are equal to or surpass the costs of the merger to those ratepayers.

16.1 Bill Credit - PSNC will create a regulatory liability of $3.75 million representing a refund to customers of 2017 revenues and will subsequently provide such refund to customers as a bill credit of $1.25 million on January 1, 2019 or as soon thereafter as practicable, another bill credit of $1.25 million on January 1, 2020, and a final bill credit of $1.25 million on January 1, 2021.

16.2 Rate Moratorium - PSNC will not file an application for a general rate case proceeding to adjust its rates and charges before April 20, 2021. PSNC will not increase its non-gas cost margin in its rates until November 1, 2021, except for the following reasons: (1) adjustments or changes pursuant to Rider C (Customer Usage Tracker), Rider D (Purchased Gas Adjustment Procedures), and Rider E (Integrity Management Tracker) pursuant to G.S. 62-133.4, G.S. 62-133.7, and G.S. 62-133.7A; (2) to reflect the financial impact of governmental action (legislative, executive, or regulatory) having a substantial specific impact on the gas industry generally or on a segment thereof that includes PSNC, including but not limited to major expenditures for environmental compliance; (3) to implement natural gas expansion surcharges imposed pursuant to G.S. 62-158; or (4) to reflect the financial impact of major expenditures associated with force majeure. In addition, PSNC shall not file for any cost deferral during or covering any period from the date of an order approving the merger until after October 31, 2021, except: (1) to reflect the financial impact of governmental action (legislative, executive, or regulatory) having a substantial specific impact on the gas industry generally or on a segment thereof that includes PSNC, including but not limited to major expenditures for environmental compliance; or (2) to reflect the financial impact of major expenditures associated with force majeure. This provision does not indicate that the Public Staff would support, or that the Commission would approve, such cost deferral.

16.3 Customer Service: PSNC agrees to maintain current levels of customer service and behavior towards customers, as well as current levels of professional cooperation with regulators, consumer advocates, and intervenors.

16.4 Cost Saving Opportunities: The electric utility operations of DENC and SCE&G, along with their affiliates and subsidiaries, will look for post-Merger opportunities to engage in joint planning, purchasing, and services that will result in cost savings to DENC's retail electric customers, while not compromising reliability or service quality.

16.5 Most Favored Nations Clause - Following the approval of the Merger by the state commissions of Georgia, South Carolina, and any other jurisdictions where DENC or PSNC must obtain approval, and approval of merger-related affiliate agreements and any other merger-related filings required to be or otherwise approved by any applicable jurisdiction, any mechanisms pursuant to which benefits and ratepayer protections are provided to DENC and/or PSNC retail customers in each of these states will be reviewed to identify the states in which each of DENC's and/or PSNC's retail customers will receive the largest financial (including, but not limited to, rate reductions, rebates, refunds, other payments, bill credits, rate moratoriums, etc.) and non-financial benefits, and other ratepayer protections, on a per customer or pro rata basis. If the application of those benefits to DENC's and/or PSNC's North Carolina retail ratepayers would result in a greater level of benefits and/or protections than that which has otherwise been provided for their North Carolina retail customers in these Regulatory Conditions, then the benefits and protections to that utility's North Carolina retail ratepayers will be increased to match the greatest level of benefits and protections provided to the DENC and/or PSNC retail ratepayers in any of the other jurisdictions. Application of this methodology is intended to ensure that DENC's and PSNC's North Carolina retail customers receive the benefit of a "Most Favored Nation" status with regard to the provision of Merger benefits and protections among the states named above. In no event will the application of the methodology cause North Carolina retail customers' benefits or protections to be reduced. To facilitate this review, DENC and PSNC will jointly file final Orders, Stipulations, etc., from all jurisdictions listed above.

CODE OF CONDUCT GOVERNING THE RELATIONSHIPS AMONG DOMINION ENERGY NORTH CAROLINA, PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC., THEIR AFFILIATES, AND THEIR NONPUBLIC UTILITY OPERATIONS

I. DEFINITIONS

For purposes of this Code of Conduct, the terms listed below shall have the following definitions:

Affiliate: Dominion Energy, or any business entity of which ten percent (10%) ormore is owned or controlled, directly or indirectly, by Dominion Energy. For purposes of this Code of Conduct, Dominion Energy and any business entity controlled by it are considered to be Affiliates of DENC and PSNC, and DENC and PSNC are considered to be Affiliates of each other.

Commission: The North Carolina Utilities Commission.

Confidential Systems Operation Information or CSOI: Non-public information that pertains to Electric Services provided by DENC, including, but not limited to, information concerning electric generation, transmission, distribution, or sales, and non-public information that pertains to Natural Gas Services provided by PSNC, including, but not limited to, information concerning transportation, storage, distribution, gas supply, or other similar information.

Customer: Any retail electric customer of DENC in North Carolina and any Commission- regulated natural gas sales or natural gas transportation customer of PSNC located in North Carolina.

Customer Information: Non-public information or data specific to a Customer or a group of Customers, including, but not limited to, electricity consumption, natural gas consumption, load profile, billing history, or credit history, that is or has been obtained or compiled by DENC or PSNC in connection with the supplying of Electric Services or Natural Gas Services to that Customer or group of Customers.

DENC: Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina, the business entity, wholly owned by Dominion Energy, that holds the franchises granted by the Commission to provide Electric Services within its North Carolina service territory and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina. DENC refers to the system business and operation of Virginia Electric and Power Company, and not simply the North Carolina retail assigned or allocated portions of that business and operation.

Dominion Energy: Dominion Energy, Inc., which is the current holding company parent corporation of DENC and PSNC, and any successor company.

Electric Services: Commission-regulated electric power generation, transmission, distribution, delivery, and retail sales, and other related services, including, but not limited to, administration of Customer accounts and rate schedules, metering, billing, standby service, backups, and changeovers of electric service to other suppliers.

FERC: The Federal Energy Regulatory Commission.

Fuel and Purchased Power Supply Services: All fuel for generating electric power and purchased power obtained by DENC from sources other than DENC for the purpose of providing Electric Services.

Fully Distributed Cost: All direct and indirect costs, including overheads and an appropriate cost of capital, incurred in providing the goods and services in question.

Gas Marketing Affiliate: An Affiliate, the business unit of an Affiliate, or the Nonpublic Utility Operations of PSNC that is engaged in the unregulated sale, arrangement, brokering, or management of gas supply, pipeline capacity, or gas storage.

Gas Marketing Affiliate Personnel: An employee or other representative of a Gas Marketing Affiliate that is involved in fulfilling the business purpose of the gas marketing affiliate. An officer or board member of both PSNC and a Gas Marketing Affiliate shall not be considered Gas Marketing Affiliate Personnel unless that individual is directly involved in the day-to-day fulfillment of the business purpose of the Gas Marketing Affiliate.

Market Value: The price at which property, goods, or services would change hands in an arm's-length transaction between a buyer and a seller without any compulsion to engage in a transaction, and both having reasonable knowledge of the relevant facts.

Merger: All transactions contemplated by the Agreement and Plan of Merger between Dominion Energy and SCANA Corporation.

Natural Gas Services: Commission-regulated natural gas sales and natural gas transportation, and other related services, including, but not limited to, administration of Customer accounts and rate schedules, metering and billing, and standby service.

Nonaffiliated Gas Marketer: An entity, not affiliated with DENC or PSNC, engaged in the unregulated sale, arrangement, brokering, or management of gas supply, pipeline capacity, or gas storage.

Nonpublic Utility Operations: All business operations engaged in by DENC or PSNC involving activities (including the sales of goods or services) that are not regulated by the Commission or otherwise subject to public utility regulation at the state or federal level.

Non-Utility Affiliate: Any Affiliate, including Service Company, other than a Utility Affiliate, DENC, or PSNC.

Personnel: An employee or other representative of DENC, PSNC, Dominion Energy, another Affiliate, or a Nonpublic Utility Operation, who is involved in fulfilling the business purpose of that entity.

PSNC: Public Service Company of North Carolina, Inc., the business entity, wholly owned by Dominion Energy and SCANA, that holds the franchise granted by the Commission to provide Natural Gas Services within its North Carolina service territory and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

PSNC Operating Personnel: An employee or other representative of PSNC that is directly involved on a day-to day basis in the acquisition, marketing, pricing, or scheduling of gas supply, interstate pipeline capacity, or gas storage facilities on behalf of PSNC. PSNC Operating Personnel also includes personnel directly on a day-to day basis involved in managing PSNC's facilities or responsible for determining which Customers to curtail, or involved in selling products and services to PSNC's Customers eligible to purchase gas, products, and services from persons other than PSNC.

Public Staff: The Public Staff of the North Carolina Utilities Commission.

Regulatory Conditions: The conditions imposed by the Commission in connection with or related to the Merger.

Service Company: A centralized service company Affiliate that provides Shared Services to DENC, PSNC, other Affiliates, and/or the Nonpublic Utility Operations of DENC or PSNC, singly or in any combination.

Shared Services: The services that meet the requirements of the Regulatory Conditions approved in Docket Nos. E-22, Sub 551 and G-5, Sub 585, or subsequent orders of the Commission, and that the Commission has explicitly authorized DENC and PSNC to take from Service Company pursuant to a service agreement (a) filed with the Commission pursuant to G.S. 62-153(b), thus requiring acceptance and authorization by the Commission, and (b) subject to all other applicable provisions of North Carolina law, the rules and orders of the Commission, and the Regulatory Conditions.

Shipper: A Gas Marketing Affiliate, Nonaffiliated Gas Marketer, a municipal gas customer, or an end-user of gas.

Utility Affiliates: The regulated utility operations of The East Ohio Gas Company (Dominion Energy Ohio), Hope Gas, Inc. (Dominion Energy West Virginia), Questar Gas Company (Dominion Energy Utah, Dominion Energy Wyoming, and Dominion Energy Idaho), and South Carolina Electric & Gas Company (SCE&G).

II. GENERAL

This Code of Conduct establishes the minimum guidelines and rules that apply to the relationships, transactions, and activities involving the public utility operations of DENC and PSNC, Dominion Energy, other Affiliates, or the Nonpublic Utility Operations of DENC and PSNC, to the extent such relationships, transactions, and activities affect operations of DENC and PSNC in their respective service areas. DENC, PSNC, and the other Affiliates are bound by this Code of Conduct pursuant to Regulatory Condition 5.1 approved by the Commission in Dockets No. E-22, Sub 551, and G-5, Sub 585. This Code of Conduct is subject to modification by the Commission as the public interest may require, including, but not limited to, addressing changes in the organizational structure of DENC, PSNC, Dominion Energy, other Affiliates, or the Nonpublic Utility Operations; changes in the structure of the electric industry or natural gas industry; or other changes that warrant modification of this Code.

DENC or PSNC may seek a waiver of any aspect of this Code of Conduct by filing a request with the Commission showing that circumstances in a particular case justify such a waiver.

III. STANDARDS OF CONDUCT

A. Independence and Information Sharing

1. Separation:

(a) DENC, PSNC, Dominion Energy, and the other Affiliates shall operate independently of each other and in physically separate locations to the maximum extent practicable; provided, however, that (i) Gas Marketing Affiliate Personnel must be located in a facility that is physically separate from that used by the PSNC Operating Personnel performing similar functions and (ii) to the extent that the Commission has approved or accepted a service company-to-utility or utility-to-utility service agreement or list, DENC, PSNC, Dominion Energy, and the other Affiliates may operate as described in the agreement or list on file at the Commission. DENC, PSNC, Dominion Energy, and each of the other Affiliates shall maintain separate books and records. Each of DENC's and PSNC's Nonpublic Utility Operations shall maintain separate records from those of DENC's and PSNC's public utility operations to ensure appropriate cost allocations and any arm's-length transaction requirements.

(b) PSNC Operating Personnel may not perform any of the following functions on behalf of a Gas Marketing Affiliate:

(i) Purchase gas, pipeline capacity, or storage capacity.
(ii) Market or sell gas and related services.
(iii) Price or administer products and services.
(iv) Hire and/or train Gas Marketing Affiliate Personnel.
(v) Offer consulting services regarding gas functions.

(c) With respect to PSNC and a Gas Marketing Affiliate, an individual may be an officer or a member of the board of directors of both PSNC and a Gas Marketing Affiliate provided that the individual does not obtain or use knowledge of market-sensitive information for more than one of the entities. PSNC shall post on its website the identity, job title, and responsibilities for each officer or board member that falls within the definition of PSNC Operating Personnel.

2. Disclosure of Customer Information:

(a) Upon request, and subject to the restrictions and conditions contained herein, DENC and PSNC may provide Customer Information to Dominion Energy or another Affiliate under the same terms and conditions that apply to the provision of such information to non-Affiliates. In addition, DENC may provide Customer Information to its Nonpublic Utility Operations under the same terms and conditions that apply to the provision of such information to non-Affiliates.
(b) Except as provided in Section III.A.2.(f), Customer Information shall not be disclosed to any Affiliate or non-affiliated third party without the Customer's consent, and then only to the extent specified by the Customer. Consent to disclosure of Customer Information to Affiliates of DENC and PSNC or to DENC's Nonpublic Utility Operations may be obtained by means of written, electronic, or recorded verbal authorization upon providing the Customer with the information set forth in Attachment A or in a format that is otherwise acceptable to the Public Staff; provided, however, that DENC and PSNC retain such authorization for verification purposes for as long as the authorization remains in effect. Written, electronic, or recorded verbal authorization or consent for the disclosure of PSNC's Customer Information to PSNC's Nonpublic Utility Operations is not required.
(c) If the Customer allows or directs DENC or PSNC to provide Customer Information to Dominion Energy, another Affiliate, or to DENC's Nonpublic Utility Operations, then DENC or PSNC shall ask if the Customer would like the Customer Information to be provided to one or more non-Affiliates. If the Customer directs

DENC or PSNC to provide Customer Information to one or more non-Affiliates, the Customer Information shall be disclosed to all entities designated by the Customer contemporaneously and in the same manner.

(d) Section III.A.2 shall be permanently posted on DENC's and PSNC's website(s).

(e) No DENC or PSNC employee who is transferred to Dominion Energy or another Affiliate shall be permitted to copy or otherwise compile any Customer Information for use by such entity except as authorized by the Customer pursuant to Section III.A.2.(b). DENC and PSNC shall not transfer any employee to Dominion Energy or another Affiliate for the purpose of disclosing or providing Customer Information to such entity.

(f) Notwithstanding the prohibitions established by this Section III.A.2:

(i) DENC and PSNC may disclose Customer Information to Service Company, any other Affiliate, or a non- affiliated third party without Customer consent to the extent necessary for the Affiliate or non-affiliated third party to provide goods or services to DENC or PSNC and upon the written agreement of the other Affiliate or non-affiliated third party to protect the confidentiality of such Customer Information. To the extent the Commission approves a list of services to be provided and taken pursuant to one or more utility-to-utility service agreements, then Customer Information may be disclosed pursuant to the foregoing exception to the extent necessary for such services to be performed.

(ii) DENC may disclose Customer Information to its Nonpublic Utility Operations without Customer consent to the extent necessary for the Nonpublic Utility Operations to provide goods or services to DENC and upon the written agreement of the Nonpublic Utility Operations to protect the confidentiality of such Customer Information.

(iii) DENC and PSNC may disclose Customer Information if a state or federal regulatory agency or court of competent jurisdiction over the disclosure of the Customer Information requires the disclosure.

(iv) DENC may disclose Customer Information to PJM Interconnection, L.L.C. (PJM), and its Market Monitoring Unit (MMU), without Customer consent, but only to the extent necessary for PJM or PJM's MMU to perform duties for DENC as allowed in Docket No. E-22, Sub 418, the performance of which requires the provision of Customer Information. DENC shall designate Customer Information as confidential, or shall direct PJM and PJM's MMU to treat

Customer Information as confidential, prior to such provision, and any Customer Information provided shall be considered to be "a Member's confidential data or information" pursuant to, and subject to the provisions of, Section 18.17 of the PJM Operating Agreement; provided, however, that in the event Section 18.17 is changed, the exception provided herein is subject to review by the Commission to determine whether the changed procedures provide sufficient protection. DENC may not authorize PJM or PJM's MMU to release such Customer Information except as allowed by this section.

(g) DENC and PSNC shall take appropriate steps to store Customer Information in such a manner as to limit access to those persons permitted to receive it and shall require all persons with access to such information to protect its confidentiality.

(h) DENC and PSNC shall establish guidelines for its employees and representatives to follow with regard to complying with this Section III.A.2.

(i) No Service Company employee may use Customer Information to market or sell any product or service to DENC's or PSNC's Customers, except in support of a Commission-approved rate schedule or program or a marketing effort managed and supervised directly by DENC or PSNC.

(j) Service Company employees with access to the Customer Information must be prohibited from making any improper indirect use of the data, including directing or encouraging any actions based on the Customer Information by employees of Service Company that do not have access to such information, or by other employees of Dominion Energy or other Affiliates or Nonpublic Utility Operations of DENC.

(k) Should any inappropriate disclosure of DENC or PSNC Customer Information occur at any time, DENC or PSNC shall promptly file a statement with the Commission describing the circumstances of the disclosure, the Customer Information disclosed, the results of the disclosure, and the steps taken to mitigate the effects of the disclosure and prevent future occurrences.

(l) Notwithstanding the foregoing, PSNC shall not disclose information provided by Nonaffiliated Gas Marketers and Customers to its Gas Marketing Affiliate, unless such parties specifically authorize disclosure of the information.

3. Disclosure of Confidential Systems Operation Information – The disclosure of Confidetial Systems Operation Information of DENC and PSNC shall be governed as follows:

(a) CSOI shall not be disclosed by DENC or PSNC to an Affiliate or a Nonpublic Utility Operation unless it is disclosed to all competing non-Affiliates contemporaneously and in the same manner. Disclosure to non-Affiliates is not required under the following circumstances:

(i) The CSOI is necessary for the performance of services approved to be performed pursuant to one or more Affiliate utility-to-utility service agreements.
(ii) A state or federal regulatory agency or court of competent jurisdiction over the disclosure of the CSOI requires the disclosure.
(iii) The CSOI is provided to employees of Service Company or to an Affiliate pursuant to an agreement filed with the Commission pursuant to G.S. 62-153, provided that the agreement specifically describes the types of CSOI to be disclosed.
(iv) The CSOI is provided to employees of DENC's or PSNC's Utility Affiliates for the purpose of sharing best practices and otherwise improving the provision of regulated utility service.
(v) The CSOI is provided to an Affiliate pursuant to an agreement filed with the Commission pursuant to G.S. 62-153, provided that the agreement specifically describes the types of CSOI to be disclosed.
(vi) Disclosure is otherwise essential to enable DENC to provide Electric Services to its Customers or for PSNC to provide Natural Gas Services to its Customers.
(vii) Disclosure of the CSOI is necessary for compliance with the Sarbanes-Oxley Act of 2002.

(b) Any CSOI disclosed pursuant to Section III.A.3.(a)(i)-(vi) shall be disclosed only to employees that need the CSOI for the purposes covered by those exceptions and in as limited a manner as possible. The employees receiving such CSOI must be prohibited from acting as conduits to pass the information to any Affiliate(s) and must have explicitly agreed to protect the confidentiality of such CSOI.

(c) For disclosures pursuant to Section III.A.3.(a)(vi) and (vii), DENC and PSNC shall include in their annual affiliated transaction reports the following information:

(i) The types of CSOI disclosed and the name(s) of the Affiliate(s) to which it is being, or has been, disclosed;
(ii) The reasons for the disclosure; and
(iii) Whether the disclosure is intended to be a one-time occurrence or an ongoing process.

To the extent a disclosure subject to the reporting requirement is intended to be ongoing, only the initial disclosure and a description of any processes governing subsequent disclosures need to be reported.

(d) DENC, PSNC, and Service Company employees with access to CSOI must be prohibited from making any improper indirect use of the data, including directing or encouraging any actions based on the CSOI by employees that do not have access to such information, or by other employees of Dominion Energy or other Affiliates or Nonpublic Utility Operations of DENC and PSNC.

(e) Should the handling or disclosure of CSOI by the Service Company, or another Affiliate or Nonpublic Utility Operation, or its respective employees, result in (i) a violation of DENC's FERC Statement of Policy and Code of Conduct (FERC Code), 18 CFR 358 - Standards of Conduct for Transmission Providers (Transmission Standards), or any other relevant FERC standards or codes of conduct, (ii) the posting of such data on an Open Access Same-Time Information System (OASIS) or other Internet website, or (iii) other public disclosure of the data, DENC and PSNC shall promptly file a statement with the Commission in Docket Nos. E-22, Sub 551C, and G-5, Sub 585C, respectively, describing the circumstances leading to such violation, posting, or other public disclosure describing the circumstances leading to such violation, posting, or other public disclosure, any data required to be posted or otherwise publicly disclosed, and the steps taken to mitigate the effects of the current and prevent any future potential violation, posting, or other public disclosure.

(f) Should any inappropriate disclosure of CSOI occur at any time, DENC or PSNC shall promptly file a statement with the Commission in Dockets No. E-22, Sub 551C, and G-5, Sub 585C, respectively, describing the circumstances of the disclosure, the CSOI disclosed, the results of the disclosure, and the steps taken to mitigate the effects of the disclosure and prevent future occurrences.

(g) Unless publicly noticed and generally available, should the FERC Code, the Transmission Standards, or any other relevant FERC standards or codes of conduct be eliminated, amended, superseded, or otherwise replaced, DENC shall file a letter with the Commission in Docket No. E-22, Sub 551D, describing such action within 60 days of the action, along with a copy of any amended or replacement document.

B. Nondiscrimination

1. General – DENC's and PSNC's employees and representatives shall not unduly discriminate against non-Affiliated entities.

2. Preferences – In responding to requests for Electric Services, Natural Gas Services, or both, DENC and PSNC shall not provide any preference to Dominion Energy, another Affiliate, or a Nonpublic Utility Operation, or to any customers of such an entity, as compared to non-Affiliates or their customers. Moreover, neither DENC, PSNC, Dominion Energy, nor any other Affiliates shall represent to any person or entity that Dominion Energy, another Affiliate, or a Nonpublic Utility Operation will receive any such preference.

3. Application of Tariffs – DENC and PSNC shall apply the provisions of their respective tariffs equally to Dominion Energy, the other Affiliates, the Nonpublic Utility Operations, and non-Affiliates.

4. Requests for Service:

(a) DENC and PSNC shall process all similar requests for Electric Services, Natural Gas Services, or both, in the same timely manner, whether requested on behalf of Dominion Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated entity.

(b) PSNC shall treat similarly situated Shippers in the same manner with respect to the delivery of gas on distribution facilities, contract terms, the scheduling of gas supplies, balancing provisions, and allocation of gas supplies and capacity at city gate stations.

(c) PSNC shall post on its website its criteria for evaluating proposals from Shippers. PSNC shall not give one Shipper any form of preference over other similarly situated Shippers in matters relating to assignment, release, or other transfer of capacity rights on interstate pipeline systems.

5. Speaking for Utility – No Personnel of DENC, PSNC, Dominion Energy, or another Affiliate shall indicate, represent, or otherwise give the appearance to another party that Dominion Energy or another Affiliate speaks on behalf of DENC or PSNC; provided, however, that this prohibition shall not apply to employees of Service Company providing Shared Services or to employees of another Affiliate to the extent explicitly provided for in an affiliate agreement that has been accepted by the Commission. In addition, no Personnel of a Nonpublic Utility Operation shall indicate, represent, or otherwise give the appearance to another party that they speak on behalf of DENC's or PSNC's regulated public utility operations.

6. Advantages – No Personnel of DENC, PSNC, Dominion Energy, another Affiliate, or a Nonpublic Utility Operation shall indicate, represent, or otherwise give the appearance to another party that any advantage to that party with regard to Electric Services or Natural Gas Services exists as the result of that party dealing with Dominion Energy, another Affiliate, or a Nonpublic Utility Operation, as compared with a non-Affiliate.

7. Tying – DENC and PSNC shall not condition or otherwise tie the provision or terms of any Electric Services or Natural Gas Services to the purchasing of any goods

or services from, or the engagement in business of any kind with, Dominion Energy, another Affiliate, or a Nonpublic Utility Operation.

8. Information to Customers:

(a) When any DENC or PSNC Personnel receives a request for information from or provides information to a Customer about goods or services available from Dominion Energy, another Affiliate, or a Nonpublic Utility Operation, the Personnel shall advise the Customer that such goods or services may also be available from non-Affiliated suppliers.

(b) All PSNC information pertaining to interstate pipeline transportation, storage, distribution, or gas supply that is provided to a Gas Marketing Affiliate shall be made available to all Shippers on a contemporaneous, nondiscriminatory, and non-preferential basis by posting the information on its website and provided in a written form upon the request of a Shipper. Aggregate customer information and market data made available to Shippers shall be made available on a similar basis.

(c) PSNC shall post on its website a current list of contact persons and telephone numbers of all gas marketers that are active on its system.

9. Disclosure of Customer Information – Disclosure of Customer Information to Dominion Energy, another Affiliate, or a Nonpublic Utility Operation, or a non-Affiliated entity shall be governed by Section III.A.2. of this Code of Conduct.

10. Unless otherwise directed by order of the Commission, electric generation shall not receive a priority of use from PSNC that would supersede or diminish PSNC's provision of service to its human needs firm residential and commercial customers.

11. PSNC shall file an annual report with the Commission summarizing all requests or inquiries for Natural Gas Services made by a non-utility generator, PSNC's response to the request, and the status of the inquiry.

C. Marketing

1. Joint Marketing – The public utility operations of DENC and PSNC may engage in joint sales, joint sales calls, joint proposals, or joint advertising (a joint marketing arrangement) with their Affiliates and with their Nonpublic Utility Operations, subject to compliance with other provisions of this Code of Conduct and any conditions or restrictions that the Commission may hereafter establish. DENC and PSNC shall not otherwise engage in such joint activities without making such opportunities available to comparable third parties.

2. Affiliate Disclaimers – Neither Dominion Energy nor any of the other Affiliates shall use the names or logos of DENC or PSNC in any communications targeted at DENC's or PSNC's North Carolina service territories without the following disclaimers:

(a) "[Dominion Energy/Affiliate] is not the same company as [DENC/PSNC], and [Dominion Energy/Affiliate] has separate management and separate employees;"
(b) "[Dominion Energy/Affiliate] is not regulated by the North Carolina Utilities Commission or in any way sanctioned by the Commission;"
(c) "Purchasers of products or services from [Dominion Energy/Affiliate] will receive no preference or special treatment from [DENC/PSNC];" and
(d) "A customer does not have to buy products or services from [Dominion Energy/Affiliate] in order to continue to receive the same safe and reliable electric service from DENC or natural gas service from PSNC."

3. Nonpublic Utility Operations Disclaimers:

(a) Nonpublic Utility Operations may not use the names or logos of DENC or PSNC in any communications targeted at DENC's or PSNC's North Carolina service territories without the following disclaimer:

> "[Name of product or service being offered by Nonpublic Utility Operation] is not part of the regulated services offered by [DENC/PSNC] and is not in any way sanctioned by the North Carolina Utilities Commission:"

(b) DENC's Nonpublic Utility Operations may not use the name or logo of DENC in any communications targeted at DENC's North Carolina service territory without the following disclaimers:

(i) "Purchasers of [name of product or service being offered by Nonpublic Utility Operation] from [Nonpublic Utility Operation] will receive no preference or special treatment from DENC;" and
(ii) "A customer does not have to buy this product or service from [Nonpublic Utility Operation] in order to continue to receive the same safe and reliable electric service from DENC."

The required disclaimers in this Section III.C.3.(b) must be sized and displayed in a way that is commensurate with the name and logo so that the disclaimer is at least the larger of one-half the size of the type that first displays the name and logo or the predominant type used in the communication.

D. Transfers of Goods and Services, Transfer Pricing, and Cost Allocation

1. Cross-Subsidies – Cross-subsidies involving DENC or PSNC and Dominion Energy, other Affiliates, or the Nonpublic Utility Operations are prohibited.

2. Charging of Costs – All costs incurred by Personnel of DENC or PSNC for or on behalf of Dominion Energy, other Affiliates, or the Nonpublic Utility Operations shall be charged to the entity responsible for the costs.

3. General Transfer Pricing Guidelines – The following conditions shall apply as a general guideline to the transfer prices charged for goods and services, including the use or transfer of Personnel, exchanged between and among DENC or PSNC, and, Dominion Energy, the other Non-Utility Affiliates, and the Nonpublic Utility Operations, to the extent such prices affect DENC's or PSNC's operations or costs of utility service:

(a) Except as otherwise provided for in this Section III.D., for untariffed goods and services provided by DENC or PSNC to Dominion Energy, a Non-Utility Affiliate, or a Nonpublic Utility Operation, the transfer price paid to DENC or PSNC shall be set at the higher of Market Value or DENC's or PSNC's Fully Distributed Cost.

(b) Except as otherwise provided for in this Section III.D., for goods and services provided, directly or indirectly, by Dominion Energy, a Non-Utility Affiliate other than Service Company, or a Nonpublic Utility Operation to DENC or PSNC, the transfer price(s) charged by Dominion Energy, the Non- Utility Affiliate, and/or the Nonpublic Utility Operation to DENC or PSNC shall be set at the lower of Market Value or Dominion Energy's, the Non-Utility Affiliate's, or the Nonpublic Utility Operation's Fully Distributed Cost(s). If DENC or PSNC does not engage in competitive solicitation and instead obtains the goods or services from Dominion Energy, a Non-Utility Affiliate, or a Nonpublic Utility Operation, DENC and PSNC shall implement adequate processes to comply with this Code provision and related Regulatory Conditions and ensure that in each case DENC's and PSNC's Customers receive service at the lowest reasonable cost, unless otherwise directed by order of the Commission. For goods and services provided by Service Company to DENC, PSNC, and Utility Affiliates, the transfer price charged shall be set at Service Company's Fully Distributed Cost.

(c) Tariffed goods and services provided by DENC and PSNC to Dominion Energy, other Affiliates, or a Nonpublic Utility Operation shall be provided at the same prices and terms that are made available to Customers having similar characteristics with regard to Electric Services or Natural Gas Services under the applicable tariff.

(d) With the exception of gas supply transactions, transportation transactions, or both, between DENC and PSNC, untariffed non-power, non-generation, or non-fuel goods and services provided by DENC or PSNC to DENC, PSNC, or the other Utility Affiliates or by the Utility Affiliates to DENC or PSNC shall be transferred at the supplier's Fully Distributed Cost, unless otherwise directed by order of the Commission.

(e) All PSNC deliveries to DENC pursuant to intrastate negotiated sales or transportation arrangements and combinations of sales and transportation transactions shall be at the same price and terms that are made available to other Shippers having comparable characteristics, such as nature of service (firm or interruptible, sales or transportation), pressure requirements, nature of load (process/heating/electric generation), size of load, profile of load (daily, monthly, seasonal,annual), location on PSNC's system, and costs to serve and rates. PSNC shall maintain records in sufficient detail to demonstrate compliance with this requirement.

(f) All gas supply transactions, interstate transportation and storage transactions, and combinations of these transactions, between DENC and PSNC shall be at the fair market value for similar transactions between non-affiliated third parties. DENC and PSNC shall maintain records, such as published market price indices, in sufficient detail to demonstrate compliance with this requirement.

(g) All of the margins, also referred to as net compensation, received by PSNC on secondary market sales to DENC shall be recorded in PSNC's Deferred Gas Cost Accounts and shall flow through those accounts for the benefit of ratepayers. None of the margins on secondary market sales by PSNC to DENC shall be included in the secondary market transactions subject to the sharing mechanism on secondary market transactions approved by the Commission in its Order Approving Stipulation, dated December 22, 1995, in Docket No. G-100, Sub 67. The sharing percentage on secondary market sales shall not be considered in determining the prudence of such transactions.

4. Shared Services Pricing – To the extent that DENC, PSNC, Dominion Energy, other Affiliates, or the Nonpublic Utility Operations receive Shared Services from Service Company (or its successor), these Shared Services may be jointly provided to DENC, PSNC, Dominion Energy, other Affiliates, or the Nonpublic Utility Operations on a Fully Distributed Cost basis, provided that the taking of such Shared Services by DENC and PSNC is cost beneficial on a service- by-service (e.g., accounting management, human resources management, legal services, tax administration, public affairs) basis to DENC and PSNC. Charges for such Shared Services shall be allocated in accordance with the Service Company cost allocation manual filed with the Commission pursuant to Regulatory Condition 4.5, subject to any revisions or other adjustments that may be found appropriate by the Commission on an ongoing basis.

5. Joint Purchases – DENC, PSNC, and their Utility Affiliates may capture economies-of-scale in joint purchases of goods and services (excluding the purchase of electricity or ancillary services intended for resale unless such purchase is made pursuant to a Commission-approved contract or service agreement), if such joint purchases result in cost savings to DENC's and PSNC's Customers. DENC, PSNC, and their Utility Affiliates may capture economies-of- scale in joint purchases of coal and natural gas, if such joint purchases result in cost savings to DENC's and PSNC's Customers. All joint purchases entered into pursuant to this section shall be priced in a manner that permits clear

identification of each participant's portion of the purchases and shall be reported in DENC's and PSNC's affiliated transaction reports filed with the Commission.

6. Accounting – All permitted transactions between DENC, PSNC, Dominion Energy, other Affiliates, and the Nonpublic Utility Operations shall be recorded and accounted for in accordance with the cost allocation manual required to be filed with the Commission pursuant to Regulatory Condition 4.5 and with Affiliate agreements accepted by the Commission or otherwise processed in accordance with North Carolina law, the rules and orders of the Commission, and the Regulatory Conditions.

7. Information Costs – Costs that DENC and PSNC incur in assembling, compiling, preparing, or furnishing requested Customer Information or CSOI for or to Dominion Energy, other Affiliates, or the Nonpublic Utility Operations shall be recovered from the requesting party pursuant to Section III.D.3. of this Code of Conduct.

8. Transfers of Technology and Trade Secrets – Any technology or trade secrets developed, obtained, or held by DENC or PSNC in the conduct of regulated operations shall not be transferred to Dominion Energy, another Affiliate, or a Nonpublic Utility Operation without just compensation and the filing of 60-days prior notification to the Commission. DENC and PSNC are not required to provide advance notice for such transfers to each other and may request a waiver of this requirement from the Commission with respect to such transfers to Dominion Energy, a Utility Affiliate, a Non-Utility Affiliate, or a Nonpublic Utility Operation. In no case, however, shall the notice period requested be less than 20 business days.

9. Intangible Benefits – DENC and PSNC shall receive compensation from Dominion Energy, other Affiliates, and the Nonpublic Utility Operations for intangible benefits, if appropriate.

E. Regulatory Oversight

1. Affiliate Transactions – The requirements regarding affiliate transactions set forth in G.S. 62-153 shall continue to apply to all transactions between DENC, PSNC, Dominion Energy, and the other Affiliates.

2. Books and Records – The books and records of DENC, PSNC, Dominion Energy, other Affiliates, and the Nonpublic Utility Operations shall be open for examination by the Commission, its staff, and the Public Staff as provided in G.S. 62-34, 62-37, and 62-51.

3. Generator Supply Services:

(a) If PSNC supplies any Natural Gas Services, with the exception of Natural Gas Services provided pursuant to Commission-approved contracts or service agreements, used by DENC to generate electricity, DENC shall file a report with the Commission in its annual fuel and fuel-related cost recovery case demonstrating that the purchase was prudent and the price was reasonable.

(b) To the extent North Carolina law, the orders and rules of the Commission, and the Regulatory Conditions permit Dominion Energy, an Affiliate, or a Nonpublic Utility Operation to supply DENC with Natural Gas Services or other Fuel and Purchased Power Supply Services used by DENC to provide Electric Services to Customers, and to the extent such Natural Gas Services or other Fuel and Purchased Power Supply Services are supplied, DENC shall demonstrate in its annual fuel adjustment clause proceeding that each such acquisition was prudent and the price was reasonable.

F. Utility Billing Format

To the extent any bill issued by DENC, PSNC, Dominion Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated third party includes charges to Customers for Electric Services or Natural Gas Services and non- Electric Services, non-Natural Gas Services, or any combination of such services, from Dominion Energy, another Affiliate, a Nonpublic Utility Operation, or a non- Affiliated third party, the charges for Electric Services and Natural Gas Services shall be separated from the charges for any other services included on the bill. Each such bill shall contain language in bold print stating that the Customer's Electric Services and Natural Gas Services, as applicable, will not be terminated for failure to pay for any other services billed.

G. Complaint Procedure

1. Procedures – DENC and PSNC shall establish procedures to resolve potential complaints that arise due to the relationship of DENC and PSNC with Dominion Energy, the other Affiliates, and the Nonpublic Utility Operations. The complaint procedures shall provide for the following:

(a) Verbal and written complaints shall be referred to a designated representative of DENC or PSNC.
(b) The designated representative shall provide written notification to the complainant within 15 days that the complaint has been received.
(c) DENC or PSNC shall investigate the complaint and communicate the results or status of the investigation to the complainant within 60 days of receiving the complaint.
(d) DENC and PSNC shall each maintain a log of complaints and related records and permit inspection of documents (other than those protected by the attorney/client privilege), by the Commission, its staff, or the Public Staff.

2 Notwithstanding the provisions of Section III.G.1., any complaints received through the Dominion Energy Compliance Line (or its successor), which is a confidential mechanism available to the employees of the Dominion Energy holding company system, shall be handled in accordance with procedures established for the Dominion Energy Compliance Line.

3. Commission – These complaint procedures do not affect a complainant's right to file a formal complaint or otherwise address questions to the Commission or the Public Staff regarding a complaint.

H. Natural Gas/Electricity Competition

DENC and PSNC shall continue to compete against all energy providers to serve those retail customer energy needs that can be legally and profitably served by both electricity and natural gas. The competition between DENC and PSNC shall be at a level that is no less than that which existed prior to the Merger. Without limitation as to the full range of potential competitive activity, DENC and PSNC shall maintain the following minimum standards:

1. PSNC will make all reasonable efforts to extend the availability of natural gas to as many new customers as possible.
2. In determining where and when to extend the availability of natural gas, PSNC will at a minimum apply the same standards and criteria that it applied prior to the Merger.
3. In determining where and when to extend the availability of natural gas, PSNC will make decisions in accordance with the best interests of PSNC, rather than the best interest of DENC.
4. To the extent that either the natural gas industry or the electricity industry is further restructured, DENC and PSNC will undertake to maintain the full level of competition intended by this Code of Conduct subject to the right of DENC, PSNC or the Public Staff to seek relief from or modifications to this requirement by the Commission.

CODE OF CONDUCT
ATTACHMENT

DENC/PSNC CUSTOMER INFORMATION DISCLOSURE AUTHORIZATION

For Disclosure to Affiliates:

DENC's/PSNC's Affiliates offer products and services that are separate from the regulated services provided by DENC/PSNC. These services are not regulated by the North Carolina Utilities Commission. These products and services may be available from other competitive sources.

The Customer authorizes DENC/PSNC to provide any data associated with the Customer accounts(s) residing in any DENC/PSNC files, systems, or databases **[or specify specific types of data]** to the following Affiliate(s):__________________________________. DENC/PSNC will provide this data on a nondiscriminatory basis to any other person or entity upon the Customer's authorization.

ELECTRIC – MERGER

For Disclosure to Non-Affiliates:

The Customer authorizes DENC/PSNC to provide any data associated with the Customer accounts(s) residing in any DENC/PSNC files, systems, or databases **[or specify specific types of data]** to the following non-Affiliate(s): ______________________________

For Disclosure to Nonpublic Utility Operations:

DENC offers optional, market-based products and services that are separate from the regulated services provided by DENC. These services are not regulated by the North Carolina Utilities Commission. These products and services may be available from other competitive sources.

The Customer authorizes DENC to provide any data associated with the Customer accounts(s) residing in any DENC files, systems, or databases **[or specify specific types of data]** for the purpose of offering and providing energy-related products or services to the Customer. DENC will provide this data on a nondiscriminatory basis to any other person or entity upon the Customer's authorization.

DOCKET NO. E-7, SUB 1162

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Carolinas, LLC, for Approval of Renewable Energy and Energy Efficiency Portfolio Standard Cost Recovery Rider Pursuant to N.C.G.S. § 62-133.8 and Commission Rule R8-67	)))))	ORDER APPROVING REPS AND REPS EMF RIDERS AND 2017 REPS COMPLIANCE REPORT

HEARD: Tuesday, June 5, 2018 at 9:30 a.m. in the Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

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

APPEARANCES:

For Duke Energy Carolinas, LLC:

Kendrick C. Fentress, Associate General Counsel, Duke Energy Corporation, 410 South Wilmington Street, NCRH 20/P.O. Box 2551, Raleigh, North Carolina 27601

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

For Carolina Utility Customers Association, Inc.:

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

For North Carolina Sustainable Energy Association:

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

Benjamin Smith, Regulatory Counsel, North Carolina Sustainable Energy Association, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For Southern Alliance for Clean Energy, North Carolina Justice Center, and Natural Resources Defense Council:

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

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

For Carolina Industrial Group for Fair Utility Rates III:

Warren Hicks, Attorney, Bailey & Dixon, LLP, P.O. Box 1351, Raleigh, North Carolina, 27602

For the Using and Consuming Public:

Robert B. Josey, Jr., Staff Attorney, Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, NC, 27699

BY THE COMMISSION: On March 7, 2018, Duke Energy Carolinas, LLC (DEC or the Company) filed its 2017 REPS Compliance Report and application seeking an adjustment to its North Carolina retail rates and charges pursuant to N.C.G.S. § 62-133.8(h) and Commission Rule R8-67, which require the Commission to conduct an annual proceeding for the purpose of determining whether a rider should be established to permit the recovery of the incremental costs incurred to comply with the requirements of the Renewable Energy and Energy Efficiency Portfolio Standard (REPS), N.C.G.S. § 62-133.8(b), (d), (e) and (f), and to true up any under-recovery or over-recovery of compliance costs. DEC's application was accompanied by the testimony and exhibits of Megan W. Jennings, Renewable Compliance Manager, and Veronica I. Williams, Rates and Regulatory Strategy Manager. In its application and pre-filed testimony, DEC sought approval of its proposed REPS Rider, which incorporated the Company's proposed adjustments to its North Carolina retail rates.

On March 28, 2018, DEC filed supplemental testimony and exhibits of witnesses Jennings and Williams.

On March 29, 2018, the Commission issued an Order which set this matter for hearing, established deadlines for the submission of intervention petitions, intervenor testimony, and DEC's rebuttal testimony, required the provision of appropriate public notice, and mandated compliance with certain discovery guidelines.

The following parties filed petitions and were allowed to intervene in this proceeding: North Carolina Sustainable Energy Association, Carolina Utility Customers Association, Inc., Rutherford Electric Membership Corporation (Rutherford EMC), and Blue Ridge Electric Membership Corporation (Blue Ridge EMC). The intervention and participation by the Public Staff are recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e).

On May 21, 2018, DEC filed additional supplemental testimony and revised exhibits of witnesses Jennings and Williams.

On May 23, 2018, the Public Staff filed the affidavits of Sonja R. Johnson, an Accountant in the Accounting Division of the Public Staff, and Jay B. Lucas, an Engineer in the Electric Division of the Public Staff.

On May 29, 2018, DEC and the Public Staff filed a joint motion to excuse all witnesses from the evidentiary hearing, which the Commission granted by an Order issued June 1, 2018.

On June 4, 2018, DEC filed the required affidavits of publication, demonstrating that the public notice of the hearing was published as required by the Commission's March 29, 2018 Order.

This matter came on for hearing as scheduled on June 5, 2018. DEC moved the introduction of the pre-filed testimony and exhibits of DEC witnesses Jennings and Williams, and the Public Staff moved the introduction of the pre-filed affidavits of its witnesses Johnson and Lucas. All pre-filed testimony, exhibits, and affidavits from the DEC and Public Staff witnesses were received into evidence.

Based upon the foregoing, including the testimony, exhibits, and affidavits of the parties' witnesses, the records in the North Carolina Renewable Energy Tracking System (NC-RETS) and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. DEC is a duly organized limited liability company existing under the laws of the State of North Carolina, is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North Carolina, and is subject to the jurisdiction of the North Carolina Utilities Commission as a public utility. DEC is also an electric power supplier as defined in N.C.G.S. § 62-133.8(a)(3). DEC is lawfully before this Commission based upon its application filed pursuant to N.C.G.S. § 62-133.8 and Commission Rule R8-67.

2. For calendar year 2017, the Company was required to meet at least 6% of its previous year's North Carolina retail electric sales by a combination of renewable energy and energy reductions due to the implementation of energy efficiency measures. Also in 2017, energy in the amount of at least 0.14% of the previous year's total electric power sold by DEC to its North Carolina retail customers must have been supplied by solar energy resources.

3. Beginning in 2012, N.C.G.S. § 62-133.8(e) and (f) require DEC and the other electric suppliers of North Carolina, in the aggregate, to procure a certain portion of their renewable energy requirements from electricity generated from swine and poultry waste, based on each electric power supplier's respective pro-rata share derived from the ratio of its North Carolina retail sales as compared to total North Carolina retail sales. In its Order Modifying the Swine and Poultry Waste Set-Aside Requirements and Providing Other Relief (2017 Delay Order), issued on October 16, 2017, in Docket No. E-100, Sub 113, the Commission delayed for one year the Swine Waste Set-Aside requirement, directing that the Swine Waste Set-Aside requirements will commence in 2018. In addition, the 2017 Delay Order lowered the 2017 Poultry Waste Set-Aside Requirement to 170,000 MWh state-wide, maintaining the same level as the 2016 requirement, and delayed by one year the future increases in the Poultry Waste Set-Aside Requirements.

4. Section 62-133.8(h) of the North Carolina General Statutes authorizes an electric power supplier to recover the "incremental costs" of compliance with the REPS requirements through an annual REPS rider. The "incremental costs," as defined in N.C.G.S. § 62-133.8(h)(1), include the reasonable and prudent costs of compliance with REPS "that are in excess of the electric supplier's avoided costs other than those costs recovered pursuant to N.C.G.S § 62-133.9." The term "avoided costs" includes both avoided energy costs and avoided capacity costs.

5. Under Commission Rule R8-67(e)(2), the total costs reasonably and prudently incurred during the test period to purchase unbundled renewable energy certificates (RECs) constitute incremental costs. The projected costs to purchase such RECs during the billing period constitute forecasted incremental costs.

6. DEC has agreed to provide REPS compliance services, including the procurement of RECs, to the following electric power suppliers, pursuant to N.C.G.S. § 62-133.8(c)(2)(e): Blue Ridge EMC, the City of Concord, the Town of Dallas, the Town of Forest City, the Town of Highlands, the City of Kings Mountain, and Rutherford EMC (collectively the Wholesale Customers).

7. DEC has complied with the 2017 solar set-aside requirements, for itself and the Wholesale Customers for which DEC is providing compliance services, through the procurement or generation of 85,576 RECs from solar electric facilities and metered solar thermal energy facilities. DEC has also complied with the 2017 Poultry Waste Set-Aside requirements, for itself and the Wholesale Customers for which DEC is providing compliance services, through the procurement or generation of 77,443 RECs from poultry waste-to-energy facilities, including 20,076 Senate Bill 886 RECs, which are credited as 40,152 poultry waste RECs pursuant to S.L. 2010-195 (Senate Bill 886).

8. DEC and the seven electric power suppliers for which DEC is providing compliance services met their 2017 REPS requirements, including the set-aside requirements as modified by the Commission's Orders issued in Docket No. E-100, Sub 113.

9. DEC is uncertain whether it will be able to comply with the 2018 swine waste set-aside requirements or the 2018 poultry waste set-aside requirements.

10. DEC has RECs in its inventory that were earned by hydroelectric power facilities that are owned by DEC. DEC cannot use these RECs to meet its REPS requirements because DEC's hydroelectric power facilities are renewable energy facilities, but not new renewable energy facilities. DEC's proposal to exchange these RECs for RECs held in the inventory of the North Carolina Electric Membership Corporation (NCEMC) is reasonable and serves the public interest.

11. For purposes of DEC's annual rider established pursuant to N.C.G.S. § 62-133.8(h), the test period for this proceeding is the 16-month period beginning January 1, 2017, and ending April 30, 2018. The billing period for this proceeding is the 12-month period beginning September 1, 2018 and ending August 31, 2019.

12. The research activities funded by DEC during the test period are incremental costs reasonably and prudently incurred by DEC to fund research that encourages the development of

renewable energy, energy efficiency, or improved air quality, and are within the annual $1-million limit established pursuant to N.C.G.S. 62-133.8(h)(1)(b).

13. For purposes of establishing the REPS experience modification factor (EMF) rider in this proceeding, DEC's incremental costs for REPS compliance during the test period were $26,491,680, including the costs incurred for its Wholesale Customers, and these costs were reasonably and prudently incurred. The Company's projected incremental costs for REPS compliance for the billing period total $29,409,151, including the costs incurred for its Wholesale Customers.

14. DEC's sales of RECs reviewed in this proceeding are appropriate, and DEC has accounted for them correctly.

15. DEC appropriately calculated its avoided costs and incremental REPS compliance costs for the test period and billing period, including those avoided and incremental costs specifically related both to the Company's Solar Photovoltaic Distributed Generation (Solar DG) program and to DEC's other owned solar facilities as required by the following Orders: (1) Order Granting Certificate of Public Convenience and Necessity with Conditions, Docket No. E-7, Sub 856 (issued December 31, 2008), (2) Order on Reconsideration, Docket No. E-7, Sub 856 (issued May 8, 2009); (3) Order Transferring Certificate of Public Convenience and Necessity, Docket No. E-7, Sub 1079 (issued May 16, 2016); and (4) Order Transferring Certificate of Public Convenience and Necessity, Docket No. E-7, Sub 1098 (issued May 16, 2016).

16. It is appropriate to approve DEC's request to recover other incremental costs pursuant to N.C.G.S. § 62-133.8(h)(1)(b) as incremental costs reasonably and prudently incurred to comply with the REPS requirements.

17. DEC complied with Commission's Order in Docket No. E-7, Sub 1106 by filing in this proceeding a worksheet detailing its interconnection cost allocation process related to labor and other costs. It is appropriate to require DEC to continue to file a worksheet explaining the discrete costs that DEC includes as "other incremental costs" in all future REPS Rider proceedings.

18. DEC's test period REPS expense (over-) or under-collections were an (over-) collection, including interest, of $(13,250,561) for the residential class, $(7,730,438) for the general service class, and $(1,051,822) for the industrial class, excluding the North Carolina regulatory fee (regulatory fee). The Company appropriately credited to customers' accounts the amounts received from REC suppliers during the test period related to contract amendments, penalties, and other conditions of the supply agreements as follows: $568,919 for residential, $412,380 for general service, and $25,510 for industrial. Total credits to customers' accounts including over-collections and the contract-related credits were $13,819,480 for the residential class, $8,142,818 for the general service class, and $1,077,332 for the industrial class, excluding the regulatory fee.

19. DEC's North Carolina retail prospective billing period expenses for use in this proceeding are $15,315,696 for the residential class, $11,167,611 for the general service class, and $713,415 for the industrial class, excluding regulatory fee.

20. The appropriate monthly REPS EMF riders per customer account, excluding regulatory fee, to be credited to customers during the billing period are $(0.67) for residential accounts, $(2.79) for general service accounts, and $(19.04) for industrial accounts.

21. The appropriate monthly prospective REPS riders per customer account, excluding regulatory fee, to be collected during the billing period are $0.74 for residential accounts, $3.82 for general service accounts, and $12.61 for industrial accounts.

22. The combined monthly REPS and REPS EMF rider charges per customer account, excluding the regulatory fee, to be collected during the billing period are $0.07 for residential accounts, $1.03 for general service accounts, and $(6.43) for industrial accounts. Including the regulatory fee, the combined monthly REPS and REPS EMF rider charges per customer account to be collected during the billing period are $0.07 for residential accounts, $1.03 for general service accounts, and $(6.44) for industrial accounts.

23. DEC's REPS incremental cost rider, including the regulatory fee, to be charged to each customer account for the billing period is within the annual limits established for each class in N.C.G.S. § 62-133.8(h)(4).

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-6

These findings of fact are essentially informational, jurisdictional and procedural in nature and are not contested.

Section 62-133.8(b)(1) of the North Carolina General Statues establishes a REPS requirement for all electric power suppliers in the State. The statute requires each electric public utility to provide a certain percentage of its North Carolina retail sales from various renewable energy or EE resources which are listed in N.C.G.S. § 62-133.8(b)(2) as follows: (a) generating electric power at a new renewable energy facility; (b) using a renewable energy resource to generate electric power at a generating facility other than the generation of electric power from waste heat derived from the combustion of fossil fuel; (c) reducing energy consumption through the implementation of energy efficiency measures; (d) purchasing electric power from a new renewable energy facility; (e) purchasing RECs produced from in-State or out-of-state new renewable energy facilities; (f) using electric power that is supplied by a new renewable energy facility or saved due to the implementation of an EE measure that exceeds the requirements of the REPS in any calendar year as a credit toward the requirements of the REPS in the following calendar year; or (g) implementing electricity demand reduction measures. Each of these measures is subject to additional limitations and conditions. For 2017, DEC must have met a total REPS requirement equal to 6% of its previous year's North Carolina retail electric sales by a combination of these measures.

Section 62-133.8(d) requires a certain percentage of the total electric power sold to retail electric customers in the State, or an equivalent amount of energy, to be supplied by a combination of new solar electric facilities and new metered solar thermal energy facilities. The percentage requirement for solar resources in 2017 was 0.14%.

Section 62-133.8(e) and (f) require DEC and the other electric suppliers of North Carolina, in the aggregate, to procure a certain portion of their renewable energy requirements from electricity generated from swine and poultry waste. Pursuant to the Commission's Order on Pro-Rata Allocation of Aggregate Swine and Poultry Waste Set-Aside Requirements and Motion for Clarification issued on March 31, 2010, in Docket No. E-100, Sub 113, DEC's share of the aggregate State set-aside requirements for energy from swine and poultry waste is based on the ratio of its North Carolina retail kilowatt-hour sales for the previous year divided by the previous year's total North Carolina retail kilowatt-hour sales. Pursuant to the Commission's Order on Pro-Rata Allocation of Aggregate Swine and Poultry Waste Set-Aside Requirements and Motion for Clarification also issued on March 31, 2010, in Docket No. E-100, Sub 113, DEC's share of the aggregate State set-aside requirements for energy from swine and poultry waste is based on the ratio of its North Carolina retail kilowatt-hour sales for the previous year divided by the previous year's total North Carolina retail kilowatt-hour sales. In its 2017 Delay Order, the Commission further delayed for one year the Swine Waste Set-Aside requirement; accordingly, the Swine Waste compliance requirements will now commence in compliance year 2018. The Commission also modified the 2017 Poultry Waste Set-Aside requirements to remain at the same level as the 2016 requirement (an aggregate of 170,000 megawatt -hours of electricity generated via poultry waste divided amongst the electric power suppliers), and delayed by one year the scheduled increases in the requirement (the requirement is scheduled to increase to 700,000 megawatt-hours in the aggregate for all electric power suppliers).

Section 62-133.8(h)(4) requires the Commission to allow an electric power supplier to recover all of its incremental costs incurred to comply with N.C.G.S. § 62-133.8 though an annual rider. Section 62-133.8(h)(1) provides that "incremental costs" means all reasonable and prudent costs incurred by an electric power supplier to comply with the REPS requirements that are in excess of the electric power supplier's avoided costs other than those costs recovered pursuant to N.C.G.S. § 62-133.9. The term "avoided costs" includes both avoided energy and avoided capacity costs.

Commission Rule R8-67(e)(2) provides that the "cost of an unbundled renewable energy certificate to the extent that it is reasonable and prudently incurred is an incremental cost and has no avoided cost component."

Commission Rule R8-67(e)(5) provides that "the REPS EMF rider will reflect the difference between reasonable and prudently incurred incremental costs and the revenues that were actually realized during the test period under the REPS rider then in effect."

In its 2017 compliance report, DEC stated that it provided energy resources and compliance reporting services for Blue Ridge EMC, the City of Concord, the Town of Dallas, the Town of Forest City, the Town of Highlands, the City of Kings Mountain, and Rutherford EMC, as allowed by N.C.G.S. § 62-133.8(c)(2)(e).

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7-9

The evidence supporting these findings of fact is found in the testimony and exhibits of DEC witnesses Jennings and Williams, and in the affidavit of Public Staff witness Lucas. In addition, the Commission takes judicial notice of the information contained in the North Carolina Renewable Energy Tracking System (NC-RETS). DEC's 2017 REPS Compliance Report, as revised in DEC's filings of March 28, 2018 in this docket, was admitted into evidence as Revised Jennings Exhibit No. 1.

DEC witness Jennings testified that DEC submitted its 2017 REPS compliance report as Jennings Exhibit No. 1, as revised in DEC's filing on March 28, 2018 in this docket, and that the report provided the information required by Commission Rule R8-67(c) in the aggregate for DEC and the Wholesale Customers for which DEC has agreed to provide REPS compliance services.

Witness Jennings further testified that DEC has submitted for retirement 3,627,191 RECs to meet its total requirement for 2017. She defined the "total requirement" as DEC's overall REPS requirement. Within this total, the Company has submitted for retirement 85,576 RECs to meet the Solar Set-Aside requirements, and 37,291 RECs, along with 20,076 SB 886 RECs (which count as 40,152 Poultry Waste RECs) to meet the Poultry Waste Set-Aside requirements. The billing period for this Application covers two separate compliance reporting periods with different requirements for each period. In 2018, the Company estimates that it will be required to submit for retirement 5,951,836 RECs to meet the requirements of N.C.G.S. § 62-133.8(b), or its total requirement. Within this total, the Company is also required to retire the following to comply with the requirements of N.C.G.S. § 62-133.8(d), (e) and (f), respectively: 119,038 solar RECs, 41,664 swine waste RECs, and 318,866 poultry waste RECs. In 2019, the Company estimates that it will be required to submit for retirement a total of 6,102,936 RECs to meet its total REPS requirements. Within this total, the Company projects that it will be required to retire approximately 122,062 solar RECs, 42,725 swine waste RECs, and 403,218 poultry waste RECs to meet the requirements set out in N.C.G.S. § 62-133.8(d), (e), and (f), respectively.

Witness Jennings testified that DEC has met its Solar Set-Aside requirement for the test period by procuring and producing 85,576 solar RECs and that, pursuant to NC-RETS Operating Procedures, the Company has submitted these RECs for retirement by transferring them from the Duke Energy Electric Power Supplier Account to the Duke Energy Compliance Sub-Account and the Sub-Accounts of its Wholesale Customers.

Witness Jennings further testified that the Company has complied with its general REPS requirement for 2017. Pursuant to NC-RETS Operating Procedures, the Company submitted for retirement 3,504,324 RECs to meet the general REPS requirement (DEC's total requirement, net of the Solar, Swine Waste and Poultry Waste Set-Aside requirements). Specifically, the RECs to be used for 2017 compliance have been transferred from the NC-RETS Duke Energy Electric Power Supplier account to the Duke Energy Compliance Sub-Account and the Sub-Accounts of the Wholesale Customers.

In her direct testimony, Company witness Jennings testified that compliance with both the Poultry Waste Set-Aside requirement and the Swine Waste Set-Aside requirement is dependent on the performance of energy developers on current contracts and new waste-to-energy projects scheduled to come online. Two poultry waste facilities that were operational in 2017 encountered operational issues and had to shut down to perform plant modifications. Both facilities are expected to be on-line in late 2018, but 2018 production will be lower than originally expected. Witness Jennings additionally reported that, as part of efforts to comply with the swine waste requirements, DEC entered into contracts to purchase directed biogas from swine waste in the Midwest for generating electric power at its Dan River combined cycle facility. DEC began to receive biogas from one of the Midwest projects beginning in the summer of 2017. However, the other Midwest project encountered extreme weather in the summer of 2017 that caused significant damage, leading the project to declare force majeure and terminate its contract with DEC. Witness Jennings further testified that the current swine waste projects have encountered difficulties in achieving the full REC output of their contracts due to issues including local opposition to siting of the facilities, the inability to secure firm and reliable sources of swine waste feedstock from waste producers in North Carolina, and technological challenges encountered in ramping up production.

Public Staff witness Lucas recommended that the Commission approve DEC's 2017 REPS compliance report. Specifically, he testified that for 2017 compliance, DEC needed to obtain a sufficient number of RECs and energy efficiency certificates (EECs) derived from any eligible sources so that the total equaled 6% of the total 2016 North Carolina retail electricity sales made by DEC and the Wholesale Customers. Witness Lucas additionally stated that DEC needed to obtain sufficient solar RECs to equal 0.14% of the total 2016 North Carolina retail electricity sales made by DEC and the Wholesale Customers, and to obtain sufficient RECs equal to DEC and the Wholesale Customers' pro-rata share of the 170,000 poultry waste RECs required by N.C.G.S. § 62-133.8(f), and as modified pursuant to the Commission's 2017 Delay Order. The 2017 Delay Order also delayed the 2017 swine waste set-aside requirements under N.C.G.S. § 62-133.8(e) for an additional year.

No party disputed that DEC had fully complied with the applicable REPS requirements, or argued that DEC's REPS compliance report should not be approved.

Based on the foregoing and the entire record herein, the Commission finds that DEC and the seven Wholesale Customers for which it is providing REPS compliance services have complied with the REPS requirements for 2017, as modified by the Commission's 2017 Delay Order. Therefore, the Commission concludes that DEC's 2017 REPS compliance report should be approved, and that the RECs and EECs in the related NC-RETS compliance sub-accounts for 2017 should be permanently retired. Finally, the Commission finds that DEC is uncertain whether it will be able to comply with the poultry waste and swine waste set-aside requirements for 2018 and that the Company is committed to satisfying these requirements by continuing to pursue procurement of these resources in a reasonable and prudent manner.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence supporting this finding of fact is found in the testimony of DEC witness Jennings and in the affidavit of Public Staff witness Lucas.

Witness Jennings testified that DEC has RECs in its inventory that it cannot use for its own REPS compliance because the RECs were earned by hydroelectric power facilities owned by DEC that are renewable energy facilities, not new renewable energy facilities.[1] Witness Jennings further testified that DEC has discussed with NCEMC exchanging a portion of these RECs for an equal number of RECs in NCEMC's inventory that DEC could use for its REPS compliance. She noted

[1] See Order Accepting Registration of Renewable Energy Facilities, Docket No. E-7, Subs 886, 887, 888, 900, 903, and 904 (issued July 31, 2009) (July 31, 2009 Order); and Order Accepting Registration of Renewable Energy Facilities, Docket Nos. E-7, Subs 942, 943, 945 and 946 (issued December 9, 2010).

that, unlike DEC, NCEMC could use the RECs earned by the hydroelectric power facilities for its REPS compliance because N.C.G.S. § 62-133.8(c)(2)(d) allows EMCs and municipalities to meet their REPS requirements through the purchase of RECs derived from renewable energy facilities (as opposed to new renewable energy facilities). Witness Jennings further testified that this exchange would benefit DEC's customers because it would allow DEC to meet part of its general REPS requirements through the RECs exchanged with NCEMC at no cost to DEC's customers rather than purchase additional RECs from new renewable energy facilities. In addition, NCEMC's customers would be held harmless in the transaction as this exchange would simply replace RECs in NCEMC's inventory with different RECs that NCEMC could use to meet its REPS compliance requirements.

Public Staff witness Lucas testified that the Public Staff recommends that the Commission allow the proposed exchange of RECs between DEC and NCEMC because it would benefit both parties and would not harm the customers of either electric power supplier.

Based on the foregoing and the entire record herein, the Commission finds that the proposed exchange of RECs between DEC and NCEMC is reasonable and serves the public interest. Therefore, the Commission concludes that the proposed exchange of RECs should be approved, and that DEC and NCEMC should be authorized to implement the proposed exchange.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence supporting this finding is procedural in nature, found in the testimony DEC witness Williams and the affidavits of Public Staff witnesses Johnson and Lucas, and is not contested.

Commission Rule R8-67(e)(3) provides that the test period for REPS rider proceedings shall be the same as that used by the utility in its fuel charge adjustment proceedings, which is specified in Commission Rule R8-55(c) for DEC to be the 12 months ending December 31 of each year. Commission Rule R8-67(e)(5) provides that "[t]he REPS EMF rider will reflect the difference between reasonable and prudently incurred incremental costs and the revenues that were actually realized during the test period under the REPS rider then in effect." Therefore Company witness Williams initially testified that the test period or EMF period used for this proceeding was the twelve months beginning on January 1, 2017, and ending December 31, 2017. Commission Rule R8-67(e)(5) further provides" and that "[u]pon request of the electric public utility, the Commission shall also incorporate in this determination the experienced over-recovery or under-recovery of the incremental costs up to thirty (30) days prior to the date of the hearing, provided that the reasonableness and prudence of these costs shall be subject to review in the utility's next annual REPS cost recovery proceeding." Commission Rule R8-67(e)(4) also directs that the REPS and REPS EMF riders shall be in effect for a fixed period, which "shall coincide, to the extent practical, with the recovery period for the cost of fuel and fuel-related cost rider established pursuant to Rule R8-55." In its current fuel charge adjustment proceeding, Docket No. E-7, Sub 1163, and in this proceeding, DEC proposed that its rate adjustments take effect on September 1, 2018, and remain in effect for a 12-month period. This period is referred to as the billing period.

In her Additional Supplemental Testimony, DEC witness Williams requested to update the EMF period so that DEC's over-recovery of costs experienced in the months of January through April, 2018, can be incorporated into DEC's proposed EMF rider. This would result in an EMF period from January 1, 2017 through April 30, 2018 (Updated EMF Period). Witness Williams explained that the over-recovery resulted from significantly lower actual poultry REC purchases than originally projected and incorporated into the REPS riders billed and resulting revenues collected during the Updated EMF Period.

In his affidavit, Public Staff witness Lucas stated that the Public Staff has reviewed DEC's proposed Updated EMF Period and the costs incurred during that period. He further stated that the Public Staff agrees with DEC's requested Updated EMF period, but noted that the Public Staff had not been able to fully audit the additional expenses and revenues included in the Updated EMF Period. Therefore, he recommended that the test period for DEC's REPS cost recovery rider filed in 2019 remain as January 1, 2018 through December 31, 2018, to allow for the Public Staff's complete review of revenues and expenses for the first four months of 2018.

Based on the foregoing and the entire record herein, the Commission finds that DEC's Updated EMF Period is appropriate for use in this proceeding. Therefore, the Commission finds that the test period for use in this proceeding is the 16-month period beginning January 1, 2017, and ending April 30, 2018. Further, as recommended by the Public Staff, the Commission finds that it is appropriate to make clear that the Updated EMF Period authorized by this Order does not alter the test period to be used in DEC's application for REPS cost recovery that will be filed in 2019, which shall remain as the period January 1, 2018 through December 31, 2018, allowing for a complete review of the revenues and expenses incurred during that test period.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence supporting this finding of fact is found in the testimony and exhibits of DEC witnesses Jennings and Williams.

Witness Jennings sponsored Confidential Revised Jennings Exhibit No. 3 as an exhibit to her testimony, wherein she identified the "Research," "Solar Rebate Program" and "Other Incremental" costs that the Company has incurred or projects to incur in association with REPS compliance. With respect to research costs, witness Williams demonstrated that the research costs are under the $1 million per year cap established in N.C.G.S. § 62-133.8(h)(1)(b). Revised Williams Exhibit No. 1.

Consistent with the Commission's orders in prior REPS proceedings, witness Jennings provided testimony and exhibits on the results and status of various studies, the costs of which DEC is including for recovery in its incremental REPS cost for the calendar year 2017 test period. Specifically, her testimony provided detailed information on the following research and development costs incurred by the Company associated with the REPS riders:

- CAPER, PV Synchronous Generator (PVSG) – In 2017, the Company worked with North Carolina State University (NC State) and Clemson University, through the Center for Advanced Power Engineering Research, on a project to develop and demonstrate a

40 kW PVSG system. The results of this project can be found in Jennings Exhibit No. 5. This project will continue in 2018.

- CAPER, Distributed Generation Valuation – In 2017, the Company worked with NC State and the University of North Carolina at Charlotte (UNCC) through CAPER, on a project to properly value the distributed generation in relation to its impacts on the grid, and to determine the best practices for the southeast region. The first phase of the project aims to review recently conducted studies on the value of distributed generation. The phase one results can be found in Jennings Exhibit No. 6. This project will continue in 2018.
- Closed Loop Biomass – The Company continues to support a closed-loop biomass research project to better understand yield potential for various woody crops, including Loblolly Pine, Hybrid Poplar, Hybrid Aspen, Sweetgum, Willow and Cottonwood trees. Crop production levels may take several years to reach full maturity. American Forest Management (AFM) provides project management support and periodic updates to the Company, as seen in Jennings Exhibit No. 7. In addition to its regular crop assessments, AFM started collecting woody biomass samples from various plots in 2017, which were provided to Mineral Labs so that the lab could perform Ultimate Analysis on each woody biomass sample. The results of these analyses as well as a sample report from Mineral Labs are shown in Jennings Exhibit No. 8.
- Coalition for Renewable Natural Gas – The Company joined the Coalition for Renewable Natural Gas in 2017 to add a valuable resource of knowledge and public policy advocacy in this growing sector of potential animal waste supply. The Coalition for Renewable Natural Gas provides its members with exclusive whitepapers, support on model pipeline gas specifications and access to other members for discussions on current and future projects.
- Electric Power Research Institute (EPRI) – In 2017, the Company subscribed to the following EPRI programs and seeks to recover their costs via the REPS rider: Program 193 – Renewable Generation, which includes Program PS193C – Solar. EPRI designates such study results as proprietary or as trade secrets and licenses such results to EPRI members, including DEC. As such, the Company may not disclose the information publicly. Non-members may access these studies for a fee. Information regarding access to this information can be found at http://www.epri.com/Pages/Default.aspx.
- NC State University's Future Renewable Electric Energy Delivery and Management (FREEDM) Systems Center – Duke Energy supports NC State's FREEDM Center through annual membership dues. The FREEDM partnership provides Duke Energy with the ability to influence and focus research on materials, technology, and

products that will enable the utility industry to transform the electric grid into a 2-way power flow system supporting distributed generation.

- Institute for Electrical and Electronics Engineers (IEEE) 1547 Conformity Assessment – The IEEE 1547 Conformity Assessment Steering Committee has been working to develop industry standard tools and methodologies to assure consistent and comprehensive compliance prior to utility grid interconnection sign off. IEEE and the Company share a common goal to accelerate and broaden industry adoption through the development and publication of well-designed and managed conformity assessment and certification programs. This project was about establishment and execution of an IEEE 1547 Commissioning Test demonstration for solar installation within the eGRid laboratory located at Clemson University. The project formally commissioned the operation of a 50 kW inverter, established an operational test bed for more advanced interconnection evaluation. The results of this project can be found in Jennings Confidential Exhibit No. 9.
- Distributed Energy Resource – Islanding Detection and Control (DER-IDC) – There is growing consensus in the industry that as DER grows in its penetration levels, the effectiveness of anti-islanding schemes currently in use in inverters and protective relaying schemes will degrade, and that future schemes will likely need to involve some sort of communications. Accordingly, DEC has engaged in an initial study to look at wide-scale communications methods that could be used to solve this growing concern. DEC contracted with Northern Plains Power Technologies (NPPT), an engineering consulting firm, to study data collected from Duke Energy facilities and research potential algorithms and communications methods that would be effective for communications-based Islanding Detection and Control methods. In 2017, NPPT helped the Company thoroughly evaluate the feasibility of the first desired communication technology called eLoran. There are further phases planned for this project in 2017. As part of the data collection effort, protection/control/monitoring equipment was purchased and installed at the Company's Marshall, McAlpine, and Rankin R&D sites. This equipment included several satellite clocks and a real-time automation controller. The Company also contracted with Xtensible Solutions, an information technology and services company, to develop the use-case requirements and data model for microgrids. The results of this feasibility study can be found in Jennings Confidential Exhibit No. 10. In addition, DEC contracted with Green Energy Corp, which developed the data translator for local access and filtering of streaming phasor measurement unit at distribution measurement equipment back to a phaser data

concentrator in the back-office. A status report for this project can be found in Jennings Exhibit No. 11.

- Loyd Ray Farms – The Company partnered with Duke University to develop a pilot-scale, sixty-five kilowatt (kW) swine waste-to-energy facility, which initiated operation and began producing renewable energy in 2011. Jennings Exhibit No. 12 summarizes the project's progress through December 31, 2017.
- Marshall Solar Site Algorithm – In 2017, the Company continued to work with UNCC on a project to utilize the operational data to design and implement an autonomous active and reactive power dispatch algorithm with PV farms and/or Battery Energy Storage system on any feeder considering DMS coordination. The results of this project can be found in Jennings Confidential Exhibit No. 13.
- Mini-DVAR Project – In 2016, the Company started a project to investigate a new technology manufactured by American Superconductor Corporation which makes a device called Mini-DVAR. This device can potentially be used for voltage stability/VAR support for renewable energy applications such as voltage compliance, grid reliability, efficiency, energy savings and grid integration of distributed PV. The project also included engineering design of a protection scheme with Schweitzer Engineering Laboratories, and the procurement of switch gear from ABB. In 2017, the Company completed the following tasks of the project: (1) power quality meter installation for base line data collection; (2) design and implementation of the direct transfer trip for the mini-DVAR device; (3) mini-DVAR device field installation and commissioning; and (4) test run of the mini-DVAR to verify it is fully functional. This project will continue in 2018.
- Rocky Mountain Institute (RMI) – The Company participates in eLab, a forum sponsored by RMI, composed of a number of North Carolina and nationally based entities, and organized to overcome barriers to economic deployment of distributed energy resources in the U.S. electric sector. Specifically, the Company seeks to gauge customer desires related to distributed resources and provide ideas of potential long-term solutions for distributed energy resources and microgrids.
- Swine Extrusion/Poultry Mortality – The Animal and Poultry Waste Management Center (APWMC) at NC State University – In 2017, the Company began support of the various projects being undertaken by the APWMC. The initial work is centered on drying swine lagoon solids and poultry mortalities at a farm- based level to create a higher MMBtu fuel that can be safely and easily transported to a central plant for combustion. A detailed description of the project along with future testing plans can be found in Jennings Confidential Exhibit No. 14.

The Commission finds that the costs incurred to fund the foregoing research activities during the test period are costs reasonably and prudently incurred to fund research that encourages the development of renewable energy efficiency, or improved air quality, and that these costs are incremental costs recoverable pursuant to N.C.G.S. § 62-133.8(h)(1)(b). The Commission further finds that the total costs incurred to fund these research activities during the test period are within the $1 million annual limit provided in N.C.G.S. § 62-133.8(h)(1)(b). In addition, the Commission finds that the Company has complied with the requirement to file study results or information about how to access study results for research conducted with REPS rider funds and that it is appropriate to require DEC to continue to include that information in future REPS rider applications. Therefore, the Commission concludes that DEC should be allowed to recover these incremental costs through the REPS rider charges authorized by this order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13-16

The evidence supporting these findings of fact is found in the testimony and exhibits of DEC witnesses Jennings and Williams, as well as in the affidavits of Public Staff witnesses Johnson and Lucas.

DEC witness Williams testified regarding the calculation of DEC's avoided costs and its incremental costs of compliance with REPS requirements, based on incurred and projected costs provided by witness Jennings. Consistent with Commission Rule R8-67(e)(2), which provides that the cost of an unbundled REC is an incremental cost with no avoided cost component, witness Williams included in incremental costs the total amount of costs incurred during the test period for unbundled REC purchases. Witness Williams identified the total retail and wholesale incremental costs incurred during the test period as $ 26,491,680, 2nd Revised Williams Exhibit No. 1, p. 1, and the projected incremental costs for the billing period as $ 29,409,151. Williams Exhibit No. 1, p. 2. Further, the projected costs of unbundled REC purchases discussed by witness Jennings during the billing period are included as estimated billing period incremental costs.

Witness Williams testified that, consistent with Commission Rule R8-67(a)(2), DEC's approved avoided cost rates are set forth in Rate Schedule PP-N, Purchased Power Non-Hydroelectric, and Rate Schedule PP-H, Purchased Power Hydroelectric, and Schedule PP rate schedules (collectively, Schedule PP). For executed purchased power agreements, where the price of the REC and energy are bundled, the Company used annualized combined capacity and energy rates shown on the Company's Exhibit No. 3, filed in Docket No. E-100, Sub 106; Exhibit No. 3 in Docket No. E-100, Sub 117; Exhibit No. 3 in Docket No. E-100, Sub 127; Exhibit No. 3 in Docket No. E-100, Sub 136; Exhibit No. 3 in Docket No. E-100, Sub 140; or Attachment H in Docket No. E-100, Sub 148 (depending on the dates the contracts were executed). For those purchased power agreements with terms that did not correspond with the durational terms for which rates were established in the avoided cost proceeding (i.e., two, five, ten, or fifteen-year durations), DEC computed avoided cost rates for the particular term of the purchased power agreements using the same inputs and methodology used for the Schedule PP rates approved in Docket No. E-100, Subs 106, 117, 127, 136, 140, and Sub 148, respectively. Witness Williams also stated that the estimated avoided cost components of energy and REC purchased power agreements effective during the prospective billing period were calculated in the same manner.

DEC's Solar Programs and Facilities

With respect to DEC's Solar DG program, witness Williams testified that DEC determined the avoided cost using a process similar to that described for a purchased power agreement with a non-standard duration. The inputs and methodology used for the Schedule PP rates approved in Docket No. E-100, Sub 117 were used to determine the annualized combined capacity and energy rates for the twenty-year term, corresponding to the expected life of the solar facilities. DEC similarly estimated its avoided cost and incremental cost for its new Solar PV facilities.

Regarding the Company's other owned solar facilities, orders approving the transfers of Certificates of Public Convenience and Necessity (CPCN) were issued by the Commission on May 16, 2016 for both the Mocksville (Docket No. E-7, Sub 1098) and the Monroe (Docket No. E-7, Sub 1079) facilities, and the order approving the CPCN for construction of the Woodleaf Solar Facility was issued on June 16, 2016 (DEC Solar PV Orders). The 15 MW Mocksville Solar Facility was placed in service in December 2016, and the 60 MW Monroe Solar Facility was placed in service in April 2017. An annual revenue requirement, including capital and operations and maintenance costs, was calculated for each project for all years of the expected service life of the project. The present value of the total project revenue requirement was levelized over the project life to produce a level annual revenue requirement, which was compared to avoided cost to determine any annual incremental cost subject to recovery through the REPS rider. The Woodleaf Solar Facility is expected to be in service by year-end 2018. The Company also calculated an estimated annual levelized revenue requirement for the Woodleaf Solar Facility applicable to the billing period.

The avoided cost for these projects is determined in similar fashion to the method used to determine avoided cost for the Company's Solar DG program. The total annual revenue requirements per megawatt hour (MWh) for the facilities, computed based on updated tax benefit assumptions and actual completed project costs as available, were greater than the applicable avoided costs per MWh, as was the case when the projects were submitted for approval in the CPCN proceedings. The Commission in its DEC Solar PV Orders limited cost recovery for these projects in the Company's REPS riders to the equivalent of the standard REC offer price that DEC was offering to qualifying facilities at the time the purchase agreements were executed for the facilities. The current annual levelized total revenue requirement per MWh for each facility, computed based on updated tax benefit assumptions and actual completed project cost, as available, is greater than the applicable levelized avoided cost per MWh, as was the case when each project was submitted for approval in the applicable CPCN proceeding. Company witness Williams testified that the Company included for cost recovery in this REPS rider only the percentage of annual levelized cost equivalent to the standard REC offer price as approved by the Commission in its DEC Solar PV Orders.

The DEC Solar PV Orders also required in the appropriate REPS rider and general rate case proceedings that DEC itemize the actual monetization of all the following tax benefits included in the Company's revenue requirement analysis of each facility:

(a) the federal Section 199 deduction;
(b) the federal Investment Tax Credit (ITC) of 30% of the cost of eligible property;

(c) the five-year Modified Accelerated Cost Recovery System (MACRS) tax depreciation; and
(d) a property tax abatement of 80% on solar property.

Company witness Williams testified that the Company analyzed the monetization of the estimated tax benefits associated with the DEC Solar PV facilities to comply with the conditions in the DEC Solar PV Orders. For the Mocksville and Monroe Solar Facilities, the Company updated its original models of estimated annual revenue requirements to reflect its actual experience to date and estimated future timing of the realization of tax benefits. She explained that, in performing these updates, the original estimated project costs were retained and the tax benefit assumptions were updated to isolate the impact of the revenue requirements of the change in tax benefits achieved or expected to be achieved. Because the Woodleaf Solar Facility is not yet under construction, a complete analysis of tax benefit assumptions specific to that project was not available. Therefore, according to witness Williams, the Company only included a forecast of levelized cost limited to the approved avoided cost plus the incremental cost calculated at the cap specified by the Commission in its DEC Solar PV Orders.

Company Witness Williams also discussed the impacts of the Federal Tax Cuts and Jobs Act (the Tax Act), which was enacted on December 22, 2017, on the revenue requirement calculations for the DEC Solar PV Facilities. The Tax Act reduced the corporate federal income tax rate to 21% from 35% and eliminated the federal Section 199 manufacturing deduction, both of which affected the revenue requirement calculations for the DEC Solar PV Facilities. With respect to the Mocksville and Monroe Solar Facilities, the Company originally assumed that they would qualify for five-year MACRS tax depreciation. Witness Williams testified that at the time the applications for CPCNs for the Monroe and Mocksville Solar Facilities were made federal bonus depreciation was not available for these solar facilities. She further stated that in late 2015, however, Congress extended bonus depreciation such that both DEC-owned solar projects qualified for it. Thus, she explained that the Company expects to take the five-year MACRS depreciation on an adjusted basis of the solar asset after first taking the 50% bonus depreciation. Taking the bonus depreciation in conjunction with the five-year MACRS depreciation results in a decrease in total project cost per MWh. Witness Williams testified that realizing the tax benefit of the bonus depreciation, however, results in creating tax net operating losses, which in turn delays the Company's ability to monetize ITC and alters the basis on which MACRS is calculated. As she explained in the previous DEC REPS recovery proceeding, separately identifying the monetary effect of any delay in realizing any of the other tax benefits is not useful because the delay is linked to and results from the ability to utilize favorable bonus depreciation.

Witness Williams further explained that beginning in 2018, the Tax Act eliminates the Section 199 tax deduction, and therefore the associated reduction is removed from the composite tax rate utilized in the revenue requirement calculations. Federal ITC benefits were originally assumed to be realized in 2018 for the Mocksville Solar Facility and in 2021 for the Monroe Solar Facility, but DEC now expects to experience a delay in realizing the federal ITC benefits because it anticipates lacking sufficient taxable income against which it can take the tax credit. The Company's ability to take bonus depreciation related to many of its assets placed in service prior to the deadline established by the Tax Act, combined with the updated forecast timing of utilization of the other tax credits, contribute to the estimated lack of taxable income for utilization of the

ITC. Finally, witness Williams testified that the Company expects to realize the 80% property tax abatement as originally assumed in its estimated revenue requirements analysis.

Witness Williams also testified that the reduction in the corporate federal income tax rate from 35% to 21% affected the calculation of deferred taxes and the rates used to calculate the return on rate base as well as the levelization of the annual revenue requirement. These effects are reflected in the revenue requirement calculations beginning in year 2018. Furthermore, the accumulated deferred income tax (ADIT) balances as of year-end 2017 are reduced in the revenue requirement calculations by an estimate of the excess associated with the reduction in the federal income tax; the revenue requirement calculations beginning in year 2018 incorporate the adjusted ADIT balance.

Other Incremental and Solar Rebate Program Costs

In addition to costs incurred or projected to be incurred for bundled or unbundled RECs, witness Williams identified the "Other Incremental," "Solar Rebate Program," and "Research" costs that DEC has incurred or projects to incur in association with REPS compliance. 2nd Revised and Revised Williams Exhibit No. 1, p. 1-2. Likewise, witness Jennings identified "Other Incremental Cost," "Solar Rebate Program Costs and "Research Cost" related to REPS compliance. Revised Jennings Confidential Exhibit Nos. 2 and 3. Witness Jennings testified that "Other Incremental Costs" include labor costs associated with REPS compliance activities and non-labor costs associated with administration of REPS compliance. Witness Jennings also listed the labor costs by activity, as directed by the Commission in its August 16, 2016, Order Approving REPS Rider and REPS EMF Rider and 2015 REPS Compliance, in Docket No. E-7, Sub 1106, and witness Jennings confirmed that all internal interconnection-related labor costs and non-labor costs have not been included for recovery in this filing, per the Commission's Order in Docket No. E-2, Sub 1109. Jennings Confidential Exhibit No. 3 and Revised Confidential Exhibit No. 3. Witness Williams included the other incremental and research costs that were incurred in 2017 in the EMF calculation. She explained that these costs are estimated for the billing period and included in the proposed REPS rider. She also testified that an amount equal to the annual amortization of Solar Rebate Program costs incurred pursuant to N.C.G.S. § 62-155(f) applicable to the billing period is also included for recovery in the proposed REPS rider.

Witness Jennings provided additional detail on the inclusion of Solar Rebate Program costs for recovery in the proposed REPS rider. As required by N.C.G.S. § 62-155(f), DEC filed an application for approval of its Solar Rebate Program in Docket Nos. E-7, Sub 1166 and E-2, Sub 1167. On April 3, 2018, in Docket Nos. E-7, Sub 1166 and E-2 Sub 1167, the Commission issued an Order Modifying and Approving the Solar Rebate Program. Through the Solar Rebate Program, DEC offers reasonable incentives to residential and nonresidential customers for the installation of small customer-owned or leased solar energy facilities participating in the Company's net metering tariff. Witness Jennings explained that, consistent with N.C.G.S. §§ 62-155(f) and 62-133.8(h), the Company had included labor and non-labor costs projected to be incurred in the billing period related to implementation of the Solar Rebate Program. Witness Jennings detailed these costs, which include the annual amortization of incentives paid to customers and program administration costs, including labor, information technology, and marketing costs. Jennings Confidential Exhibit No. 3 and Revised Confidential Exhibit No. 3.

DEC witness Jennings also reported that DEC sold poultry waste RECs during the test period to other electric suppliers in North Carolina to enable the state's electric power suppliers to comply with the aggregate Poultry Waste Set-Aside requirement. Witness Jennings confirmed that the sales did not negatively impact compliance and that the proceeds were credited back to the Company's retail and wholesale REPS customers.

Public Staff witness Johnson also testified that after its review of the Company's filings and numerous responses to both written and verbal data requests, the Public Staff had "a high confidence level" that the Company had removed all interconnection-related labor costs from its request for recovery in accordance with Company guidelines and that the Company's efforts to remove interconnection-related costs were reasonable.

Conclusions

Based on the foregoing and the entire record in this proceeding, the Commission finds that DEC appropriately calculated its avoided costs and incremental REPS compliance costs for the test period and the billing period. Public Staff witnesses Johnson and Lucas both confirmed that, as part of its investigation, the Public Staff had reviewed the REPS compliance costs included in DEC's proposed REPS rider, and recommended that the Commission approve the proposed rider amounts. No party disputed DEC's methodology for calculating its avoided costs or its incremental costs incurred during the test period or projected to be incurred during the billing period, or DEC's accounting for its sales of RECs.

The Commission notes that this is the first REPS rider proceeding in which DEC has included costs associated with its Solar Rebate Program for recovery through the REPS rider. Section 62-155(f) authorizes DEC to recover all reasonable and prudent costs of incentives provided to customers and program administrative costs by amortizing the total program incentives distributed during a calendar year and administrative costs over a 20-year period, including a return component adjusted for income taxes at the utility's overall weighted average cost of capital established in its most recent general rate case, which shall be included in the costs recoverable by the public utility pursuant to N.C.G.S.§ 62-133.8(h). Additionally, N.C.G.S. § 62-133.8(h), as amended by House Bill 589, provides that an electric power supplier's cost recovery and customer charges under the REPS rider may include incremental costs incurred to "provide incentives to customers, including program costs, incurred pursuant to N.C.G.S. § 62-155(f)." Therefore, the Commission finds that DEC's inclusion of its Solar Rebate Program costs for recovery through the billing period is appropriate in this proceeding.

In addition, the Commission finds that DEC's sale of poultry RECs appropriately offset costs incurred during the Updated EMF Period. Accordingly, the Commission finds that, for purposes of establishing the REPS EMF rider in this proceeding, DEC's reasonably and prudently incurred costs for REPS compliance during the test period were $26,491,680, including the costs incurred for its Wholesale Customers. Further, the Commission finds that the Company appropriately projected incremental costs for REPS compliance during the billing period totaling $29,409,151, including the incremental costs projected to be incurred for the Wholesale Customers. Finally, the Commission finds that DEC appropriately calculated the costs of its Solar DG program and DEC's other owned solar projects for inclusion in the REPS rider. Therefore, the Commission concludes that, for the purposes of establishing the REPS rider charges in this proceeding, DEC should be authorized to recover the foregoing expenses as incremental costs reasonably and prudently incurred to comply with the REPS requirements.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 17-23

The evidence supporting these findings of fact is found in the testimony and exhibits of DEC witnesses Jennings and Williams, and in the affidavits of Public Staff witnesses Johnson and Lucas.

DEC Witness Williams demonstrated that DEC's total North Carolina retail test period over-collections (including interest) of $13,250,561 for the residential class, $7,730,438 for the general service class, and $1,051,822 for the industrial class. 2nd Revised Williams Exhibit No.2. Witness Williams further demonstrated that additional credits for contract receipts by customer class are $568,919 for residential, $412,380 for general service, and $25,510 for industrial. 2nd Revised Williams Exhibit No. 4. Total over-collections and contract-related credits by class for the EMF period are $13,819,480 for residential, $8,142,818 for general service, and $1,077,332 for industrial. Witness Williams calculated the proposed North Carolina retail monthly per-account REPS EMF credits (excluding regulatory fee) as $(0.67) for residential accounts, $(2.79) for general service accounts, and $(19.04) for industrial accounts. 2nd Revised Williams Exhibit No. 4. She also testified that she calculated the projected North Carolina retail REPS costs for the billing period of $15,315,696 for the residential class, $11,167,611 for the general service class, and $713,415 for the industrial class. See 2nd Revised Williams Exhibit No. 4. Witness Williams demonstrated that the proposed monthly prospective REPS riders per customer account, excluding the regulatory fee, to be collected during the billing period are $0.74 for residential accounts, $3.82 for general service accounts, and $12.61 for industrial accounts. 2nd Revised Williams Exhibit No. 4. The combined monthly REPS and REPS EMF rider charges per customer account, excluding regulatory fee, to be collected during the billing period are thus $0.07 for residential accounts, $1.03 for general service accounts, and $(6.43) for industrial accounts. Including the regulatory fee, the combined monthly REPS and REPS EMF rider charges per customer account to be collected during the billing period are $0.07 for residential accounts, $1.03 for general service accounts, and $(6.44) for industrial accounts. Company witness Williams also demonstrated that the Company's REPS incremental cost rider to be charged to each customer account for the billing period is within the annual cost cap established for each customer class in N.C.G.S. § 62-133.8(h)(4). 2nd Revised Williams Exhibit No. 4.

Public Staff witness Johnson stated in her affidavit that as a result of its investigation, the Public Staff recommended that the Company's proposed annual REPS EMF increment/(decrement) amounts and monthly EMF riders for each customer class be approved. Witness Johnson also stated that, excluding the regulatory fee, the annual decrement REPS EMF riders are $(8.06), $(33.44) and $(228.49) and the monthly decrement REPS EMF riders are $(0.67), $(2.79), and $(19.04), per retail customer account, for residential, general service, and industrial customers, respectively.

Public Staff witness Lucas stated in his affidavit that the Public Staff had reviewed the costs that are included in the proposed, revised rates and that the Public Staff took no issue with them. He recommended that the Commission approve DEC's proposed prospective monthly, per customer account REPS rider amounts in the following amounts: $0.74 for residential accounts, $3.82 for general service accounts, and $12.61 for industrial accounts, excluding regulatory fee.

Based upon the foregoing and the entire record herein, the Commission finds that DEC's calculations of its over collection during the test period, its incremental costs projected to be incurred during the billing period, and the resulting REPS and REPS EMF rider charges for each customer class are reasonable and appropriate. The Commission further finds that the REPS and REPS EMF rider charges are below the following annual per-account limits established in N.C.G.S. § 62-133.8(h)(4): $27.00 for residential, $150.00 for general service/commercial, and $1,000.00 for industrial. Finally, the Commission finds that the total incremental costs authorized to be recovered from DEC's customers in this proceeding are below the annual limit established in N.C.G.S. 62-133.8(h)(3) and (4). Therefore, the Commission concludes that DEC should be authorized to recover the total incremental costs incurred during the test period and projected to be incurred during the billing period, through the REPS and REPS EMF rider charges in the amounts described herein.

IT IS, THEREFORE, ORDERED as follows:

1. That DEC shall establish a REPS rider as described herein, in the amounts approved herein, and that this rider shall remain in effect for a 12-month period beginning on September 1, 2018, and expiring on August 31, 2019;

2. That DEC shall establish an REPS EMF rider as described herein, in the amounts approved herein, and that this rider shall remain in effect for a 12-month period beginning on September 1, 2018, and expiring on August 31, 2019;

3. That DEC shall file the appropriate rate schedules and riders with the Commission in order to implement the provisions of this Order as soon as practicable, but not later than ten (10) days after the date that the Commission issues orders in both this docket and in Docket No. E-7, Sub 1163;

4. That DEC shall work with the Public Staff to prepare a joint notice to customers of the rate changes ordered by the Commission in this docket, as well as in Docket No. E-7, Sub 1163, and the Company shall file such notice for Commission approval as soon as practicable, but not later than ten (10) days of the date of this order;

5. That DEC's 2017 REPS compliance report shall be, and hereby is, approved, and the RECs in DEC's 2017 compliance sub-accounts in NC-RETS and those of the Wholesale Customers shall be retired;

6. That DEC shall file in all future REPS rider applications the results of studies the costs of which were, or are proposed to be, recovered through the REPS EMF rider and REPS rider charges and, for those studies that are subject to confidentiality agreements, information regarding whether and how parties can access the results of those studies; and

7. That DEC shall continue to file a worksheet explaining the discrete costs that DEC includes as "other incremental costs" in all future REPS Rider proceedings.

ISSUED BY ORDER OF THE COMMISSION.
This the 17th day of August, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

DOCKET NO. E-7, SUB 1163

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Energy Carolinas, LLC Pursuant to N.C. Gen. Stat. § 62-133.2 and NCUC Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities	)	ORDER APPROVING FUEL CHARGE ADJUSTMENT

HEARD: Tuesday, June 5, 2018, at 9:30 a.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

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

APPEARANCES:

For Duke Energy Carolinas, LLC:

Jack Jirak, Associate General Counsel, Duke Energy Corporation, NCRH 20/P.O. Box 1551, Raleigh, North Carolina 27602-1551

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

For Carolina Utility Customers Association, Inc.:

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

For North Carolina Sustainable Energy Association:

Peter Ledford, Benjamin Smith, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For Sierra Club:

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

For Carolina Industrial Group for Fair Utility Rates III:

Warren Hicks, Bailey & Dixon, LLP, P. O. Box 1351, Raleigh, North Carolina 27602

For the Using and Consuming Public:

Dianna W. Downey, Staff Attorney, Robert B. Josey, Staff Attorney, Public Staff, North Carolina Utilities Commission, 430 N. Salisbury Street, 4326 MSC. Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On March 7, 2018, Duke Energy Carolinas, LLC (Duke Energy Carolinas, DEC, or the Company) filed an application pursuant to N.C. Gen. Stat. § 62-133.2 and Commission Rule R8-55 regarding fuel and fuel-related cost adjustments for electric utilities, along with the testimony and exhibits of Kimberly D. McGee, Eric S. Grant, Joseph A. Miller, Jr., Scott L. Batson, and Kevin Y. Houston.

Petitions to intervene were filed by the North Carolina Sustainable Energy Association (NCSEA) on March 16, 2018; by Carolina Utility Customers Association, Inc. (CUCA) on April 10, 2018; by Carolina Industrial Group for Fair Utility Rates III (CIGFUR) on May 17, 2018; and by the Sierra Club on May 21, 2018. The Commission granted NCSEA's petition to intervene on March 23, 2018, CUCA's petition to intervene on April 11, 2018, CIGFUR's petition to intervene on May 18, 2018, and the Sierra Club's petition on May 30, 2018.

On March 26, 2018, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice (Scheduling Order) in which the Commission set this matter for hearing; established deadlines for the submission of intervention petitions, intervenor testimony, and DEC rebuttal testimony; required the provision of appropriate public notice; and mandated compliance with certain discovery guidelines.

The intervention of the Public Staff is recognized pursuant to N.C. Gen. Stat. § 62-15(d) and Commission Rule R1-19(e).

On May 15, 2018, DEC filed the supplemental testimony, exhibits and work papers of Kimberly D. McGee, which reflected an increase in the amount requested in the original application.

On May 18, 2018, DEC filed a request for expedited review and approval of the proposed Second Public Notice. On May 21, 2018, the Commission issued an Order Requiring Publication of Second Public Notice.

On May 21, 2018, the Public Staff filed the testimony and exhibits of Darlene P. Peedin and Dustin Metz, which was subsequently corrected on May 22, 2018.

On May 30, 2018, DEC filed a motion to excuse Scott L. Batson and to allow Steven D. Capps to adopt Mr. Batson's pre-filed testimony. On May 31, 2018, the Commission granted the motion.

On May 31, 2018, DEC filed the rebuttal testimony of Steven D. Capps and Forest W. Rogers.

On May 31, 2018, DEC and the Public Staff filed a joint motion requesting that certain witnesses be excused from appearance at the expert witness hearing. On June 1, 2018, the Commission issued an Order excusing DEC witnesses McGee, Grant, Miller, and Houston, and Public Staff witness Peedin from appearing at the expert witness hearing.

On June 4, 2018, DEC filed affidavits of publication indicating that the initial public notice had been provided in accordance with the Commission's Scheduling Order dated March 26, 2018. On June 6, 2018, DEC filed affidavits of publication indicating that the second public notice had been provided in accordance with the Commission's Order dated May 21, 2018.

The case came on for hearing as scheduled on June 5, 2018. The prefiled direct and supplemental testimony of DEC's witnesses and the prefiled affidavits of the Public Staff's witnesses were received into evidence. No public witnesses appeared at the hearing.

On July 19, 2018, DEC and the Public Staff filed proposed orders.

Based upon the Company's verified application, the testimony, affidavits, and exhibits received into evidence at the hearing, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. Duke Energy Carolinas is a duly organized corporation existing under the laws of the State of North Carolina, is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North Carolina, and is subject to the jurisdiction of the Commission as a public utility. Duke Energy Carolinas is lawfully before this Commission based upon its application filed pursuant to N.C. Gen. Stat. § 62-133.2.

2. The test period for purposes of this proceeding is the 12 months ended December 31, 2017 (test period).

3. In its application and direct and supplemental testimony including exhibits in this proceeding, DEC requested a total increase of approximately $58.3 million as revised to its North Carolina retail revenue requirement associated with fuel and fuel-related costs, excluding the regulatory fee. The fuel and fuel-related cost factors requested by DEC included Experience Modification Factor (EMF) riders to take into account fuel and fuel-related cost under-recoveries and over-recoveries experienced during the test period and through March 2018, with an overall under-recovery of approximately $73.3 million.

4. For the test year, DEC achieved an actual nuclear capacity factor equal to 95.87% that exceeded the NERC five-year weighted industry average nuclear capacity factor of 88.76%.

5. The nuclear capacity factor of DEC during the test year avoided the rebuttable presumption of imprudence in Commission Rule R8-55.

6. The Company's baseload plants were managed prudently and efficiently during the test period so as to minimize fuel and fuel-related costs.

7. The Company's fuel and reagent procurement and power purchasing practices during the test period were reasonable and prudent.

8. The test period per book system sales are 85,087,285 megawatt-hours (MWh). The test period per book system generation (net of auxiliary use and joint owner generation) and purchased power is 91,830,315 MWh and is categorized as follows:

Net Generation Type	MWh
Coal	25,573,401
Natural Gas, Oil and Biomass	10,964,809
Nuclear	44,387,125
Hydro – Conventional	1,517,922
Hydro Pumped Storage	(868,059)
Solar DG	125,812
Purchased Power – subject to economic dispatch or curtailment	7,355,868
Other Purchased Power	2,100,330
Catawba Interchange	673,107
Total Net Generation	91,830,315

9. The appropriate nuclear capacity factor for use in this proceeding is 93.31%.

10. The North Carolina retail test period sales, adjusted for customer growth and weather, for use in calculating the EMF are 56,823,684 MWh. The adjusted North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Adjusted MWh Sales
Residential	21,099,293
General Service/Lighting	23,106,793
Industrial	12,617,598
Total	56,823,684

11. The projected billing period (September 2018-August 2019) sales for use in this proceeding are 86,966,251 MWh on a system basis and 57,030,345 MWh on a North Carolina retail basis. The projected billing period North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Projected MWh Sales
Residential	21,325,336
General Service/Lighting	23,055,058
Industrial	12,649,951
Total	57,030,345

12. The projected billing period system generation and purchased power for use in this proceeding in accordance with projected billing period system sales is 92,085,162 MWh and is categorized as follows:

Generation Type	MWh
Coal	24,506,235
Gas Combustion Turbine (CT) and Combined Cycle (CC)	15,192,940
Nuclear	43,840,571
Hydro	4,927,068
Net Pumped Storage Hydro	(3,999,271)
Solar Distributed Generation (DG)	162,037
Purchased Power	7,455,582
Total	92,085,162

13. The appropriate fuel and fuel-related prices and expenses for use in this proceeding to determine projected system fuel expense are as follows:

a. The coal fuel price is $24.75/MWh.
b. The gas CT and CC fuel price is $25.32/MWh.
c. The appropriate expense for ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions (collectively, "Reagents") is $34,275,781.
d. The total nuclear fuel price (including Catawba Joint Owners generation) is $6.53/MWh.

e. The total system purchased power cost (including the impact of Joint Dispatch Agreement (JDA) Savings Shared) is \$35.61/MWh.
f. System fuel expense recovered through intersystem sales is \$35,970,078.

14. The projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are \$1,013,394,952.

15. The Company's North Carolina retail jurisdictional fuel and fuel-related expense under-collection for purposes of the EMF was approximately \$73.3 million, consisting of an under-recovery for the residential, general service/lighting, and industrial classes of approximately \$20.7 million, \$24.7 million and \$27.9 million, respectively.

16. The increase in customer class fuel and fuel-related cost factors from the amounts approved in Docket No. E-7, Sub 1129, should be allocated between the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology that was approved by the Commission in that docket.

17. The appropriate prospective fuel and fuel-related cost factors for this proceeding for each of DEC's rate classes, excluding the regulatory fee, are as follows: 1.7003¢/kilowatt-hour (kWh) for the Residential class; 1.8314¢/kWh for the General Service/Lighting class; and 1.8020¢/kWh for the Industrial class.

18. The appropriate EMF increments established in this proceeding, excluding the regulatory fee, are as follows: 0.0980¢/kWh for the Residential class; 0.1068¢/kWh for the General Service/Lighting class; and 0.2213¢/kWh for the Industrial class.

19. The total net fuel and fuel-related costs factors for this proceeding for each of DEC's rate classes, excluding the regulatory fee, are as follows: 1.7983¢/kWh for the Residential class; 1.9382¢/kWh for the General Service/Lighting class; and 2.0233¢/kWh for the Industrial class.

20. The base fuel and fuel-related costs as approved in Docket No. E-7, Sub 1146 of 1.7828¢/kWh, 1.9163¢/kWh, and 2.0207¢/kWh for the Residential, General Service/Lighting, and Industrial customer classes, respectively will be adjusted by amounts equal to (0.0825)¢/kWh, (0.0849)¢/kWh, and (0.2187)¢/kWh for the Residential, General Service/Lighting, and Industrial customer classes, respectively. The resulting approved fuel and fuel-related costs will be further adjusted by EMF increments totaling 0.0980¢/kWh, 0.1068¢/kWh, and 0.2213¢/kWh for the Residential, General Service/Lighting, and Industrial customer classes, respectively.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding of fact is essentially informational, procedural, and jurisdictional in nature and is uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

N.C. Gen. Stat. § 62-133.2(c) sets out the verified, annualized information that each electric utility is required to furnish to the Commission in an annual fuel and fuel-related cost adjustment proceeding for a historical 12-month test period. Commission Rule R8-55(b) prescribes the 12 months ending December 31 as the test period for DEC. The Company's filing in this proceeding was based on the 12 months ended December 31, 2017.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence for this finding of fact is contained in the Application, the direct and supplemental testimony of Company witness McGee, and the entire record in this proceeding. This finding is not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4-6

The evidence for these findings of fact is contained in the direct testimony of Company witnesses Batson and Miller, the rebuttal testimony of Company witnesses Capps and Rogers and the direct testimony of Public Staff witness Metz.

Pursuant to N.C. Gen. Stat. § 62-133.2(d) and Commission Rule R8-55, the burden of proof, as to the correctness and reasonableness of any charge and as to whether the test year fuel costs were reasonable and prudently incurred, is on the utility. For purposes of determining the EMF rider, a utility must achieve either (a) an actual system-wide nuclear capacity factor in the test year that is at least equal to the national average capacity factor for nuclear production facilities based on the most recent five-year period available as reflected in the most recent NERC Generating Availability Report, appropriately weighted for size and type of plant, the NERC average, or (b) an average system-wide nuclear capacity factor, based upon a two-year simple average of the system-wide capacity factors actually experienced in the test year and the preceding year, that is at least equal to the NERC average. in order to avoid a presumption that the utility imprudently incurred the increased fuel costs and that disallowance of those costs is appropriate.

Company witness Batson[1] testified that the most recently published NERC Generating Unit Statistical Brochure (NERC Brochure) indicates an average capacity factor of 88.76% for the period 2012 through 2016 for comparable units (pressurized water reactors on a capacity-rated basis with capacity ratings at and above 800 MWs).

Company witness Batson testified that the Company's seven nuclear units operated at a system average capacity factor of 95.87% during the test period. Tr., pp. 59-60. This capacity factor, as well as the Company's 2-year average capacity factor of 96.13%, exceeded the NERC five-year industry weighted average capacity factor of 88.76%.

[1] By motion filed on May 30, 2018, DEC moved to excuse witness Batson from appearing at the evidentiary hearing and to allow witness Capps to adopt witness Batson's testimony. The Commission granted the motion by order dated May 31, 2018.

Witness Batson also testified that for the 18th consecutive year, DEC's seven nuclear units achieved a system average capacity factor exceeding 90%, ending the year, which included four refueling outages. In addition, he testified that DEC's nuclear units achieved the second best annual generation in the Company's history, falling just below the record output achieved in 2016. Id. McGuire Unit 1 established a new breaker-to-breaker run of 523.86 days leading into the unit's fall refueling outage. Id. Both McGuire units completed refueling outages during 2017, with both units setting new refueling outage duration records. Id. With a continuous cycle run of just over 715 days, Oconee Unit 2 also established a new breaker-to-breaker record leading into its fall refueling outage. The Catawba station established a new annual generation record during 2017. Id. Catawba Unit 1 established new monthly generation records during 7 of the 12 months in 2017, and Unit 1's spring refueling outage duration of 24.2 days was the second best in the unit's history. Id. Catawba Unit 2's annual generation of just over 10,377 GWHs was the second highest output in the unit's history. Id.

Company witness Miller testified concerning the performance of DEC's fossil/hydro assets. He stated that the primary objective of the Company's fossil/hydro generation department is to safely provide reliable and cost-effective electricity to DEC's customers. Tr. at 46-48. Witness Miller further stated that DEC achieves compliance with all applicable environmental regulations and maintains station equipment and systems in a cost-effective manner to ensure reliability. The Company also takes action in a timely manner to implement work plans and projects that enhance the safety and performance of systems, equipment, and personnel, consistent with providing low-cost power for its customers.

Company witness Miller testified that the Company's generating units operated efficiently and reliably during the test period. He explained that several key measures are used to evaluate operational performance, depending on the generator type: (1) equivalent availability factor (EAF), which refers to the percent of a given time period a facility was available to operate at full power, if needed (EAF is not affected by the manner in which the unit is dispatched or by the system demands; it is impacted, however, by planned and unplanned (i.e., forced outage time); (2) net capacity factor (NCF), which measures the generation that a facility actually produces against the amount of generation that theoretically could be produced in a given time period, based upon its maximum dependable capacity (NCF is affected by the dispatch of the unit to serve customer needs); (3) equivalent forced outage rate (EFOR), which represents the percentage of unit failure (unplanned outage hours and equivalent unplanned derated hours); a low EFOR represents fewer unplanned outage and derated hours, which equates to a higher reliability measure; and, (4) starting reliability (SR), which represents the percentage of successful starts. Tr., pp. 49-50.

Company witness Miller presented the following chart, which shows operation results, as well as results from the most recently published NERC Generating Availability Brochure for the period 2012 through 2016, and is categorized by generator type:

Generator Type	Measure	Review Period DEC Operational Results	2012-2016 NERC Average	Nbr of Units
Coal-Fired Test Period	EAF	78.5%	79.5%	789
	NCF	42.7%	57.6%	
	EFOR	4.8%	8.0%	
Coal-Fired Summer Peak	EAF	95.9%	n/a	n/a
Total CC Average	EAF	92.3%	84.8%	301
	NCF	81.4%	53.0%	
	EFOR	0.07%	5.5%	
Total CT Average	EAF	84.7%	87.6%	826
	SR	99.4%	98.1%	
Hydro	EAF	88.8%	81.1%	1,120

Witness Miller testified that Marshall Unit 3 completed a major turbine overhaul in Spring 2017, which included main turbine and boiler feed pump rotor maintenance. Allen Unit 3 completed an outage in Spring 2017 to replace the low pressure turbine rotor. Marshall Unit 1 completed an outage in Fall 2017. Tr. at 51. The primary purpose of this outage was to replace the HP and LP turbine rotors. Belews Creek Unit 1 completed major boiler maintenance in Fall 2017, which included secondary super heat inlet and outlet header replacements.

Witness Miller also testified that the CC fleet performed planned outages at Dan River CC and Buck CC in Spring 2017. The primary purpose of the Dan River CC outage was to perform a boroscope and heat recovery steam generator inspection. The primary purpose of the Buck CC outage was to perform a boroscope inspection on each combustion turbine. Within the hydro fleet, Cowans Ford Unit 1 had a major generator overhaul, controls upgrade, and installed a dissolved oxygen system.

Public Staff witness Metz testified that the Company met the standard of nuclear performance in Commission Rule R8-55(k) with an actual system-wide nuclear capacity factor during the test year that exceeded the NERC weighted average nuclear capacity factor. Additionally, he agreed that the Company's two-year simple average of its system-wide nuclear capacity factor exceeded the NERC average nuclear capacity factor. He testified that had DEC not met this standard, a rebuttable presumption would have been created that DEC imprudently incurred increased fuel costs during the test year. He stated that in the Public Staff's opinion, meeting the standard in Commission Rule R8-55(k) does not mean that the Company has met the burden of proving that all of its fuel costs were reasonable and were prudently incurred. It simply overcomes the presumption of imprudence. He stated that a utility can meet or exceed the NERC average overall, but still be shown to have had substandard performance at one or more individual units during the test year that could have reasonably been prevented based on what was reasonably known or reasonably should have been known at that time. In this case, while DEC avoided the presumption of imprudence under the Rule, an investigation of specific actions, decisions, and performance during specific events was still warranted to determine whether the increased fuel costs associated with replacement power should be excluded. Tr., pp. 106-107.

Witness Metz testified that there was one outage during the test year at Oconee Unit 3 that began on July 24, 2017, and lasted approximately 30 hours that was within the Company's control and could have reasonably been avoided. But for the outage, the fuel costs incurred to serve DEC's customers would have been lower and the proposed EMF to customers in this case would have been less. Therefore, he recommended that the resulting replacement power costs of $433,911, on a North Carolina retail basis, was not reasonably and prudently incurred and should not be borne by ratepayers. Tr., p. 107.

Witness Metz testified that he arrived at his recommendation after reviewing the Company's application, testimony, Root Cause Evaluation (RCE) reports or the equivalent, data request responses, and participating in a teleconference with the Company to make sure he fully understood the pertinent facts. Tr., pp. 108, 127-128.

Witness Metz testified that the Oconee outage resulted from:

> [p]reventive maintenance [taking place in the Relay House on a Power Circuit Breaker (PCB) Breaker Failure Relay (BFR) that] was inadvertently actuated.
>
> ...
>
> The Apparent Cause Evaluation (ACE) team identified two Apparent Causes for the PCB-58 BFR actuation and associated U3 [Oconee Unit 3] reactor trip. The first Apparent Cause is a lack of rigor by the Transmission technicians to utilize appropriate Human Performance Tools for ensuring actions are performed on the intended components. The second Apparent Cause is a lack of coordination between the Transmission and Nuclear organizations in implementation of the NSIA/NSOG interface.[1]

Tr., pp. 108-109.

Witness Metz testified that, in summary, Relay Technicians (RTs) from the Company's Transmission organization were performing routine maintenance immediately outside of the plant (i.e., the switchyard area where the power generation output of the plant is interconnected with the transmission system). This involved connecting test equipment to a breaker failure relay (PCB-57). During the course of their work, a RT lost orientation of the location of the PCB-57 relay on which the tests were being conducted. This loss of orientation led the RT to misidentify the relay that was under test. As a result, the RT connected to and then tested the wrong relay (PCB-58, located directly below PCB-57), causing PCB-58 to operate. In other words, the RT connected test equipment to an operational, in-service relay, causing it to perform an unintended operation. This operation caused Oconee Unit 3 to "trip" offline, thus shutting down the unit. Tr., pp. 108-110.

Witness Metz testified that the purpose of the test was to ensure the proper operation of the power circuit breaker (PCB) relay for a transmission line. The test should have caused PCB-57 to actuate, changing its electrical state from either closed to open or vice versa. The transmission

[1] Metz Confidential Exhibit 3, ACE Report, p. 3.

line (Asbury line) associated with PCB-57 was already out of service, so the actuation from the test should have only been a simulation. However, because the test was performed in error on the wrong relay (PCB-58), the test caused Oconee Unit 3 to experience a load rejection-like event, initiating the safety/shutdown systems within the generation plant. The outage lasted approximately 29.52 hours before the unit was back online. Tr., p. 110.

Witness Metz described the factors or contributing events that resulted in the outage. The first factor or contributing event was an organizational weakness that led to a communication breakdown between two intra-Company organizations, Nuclear and Transmission (referred to within Metz Confidential Exhibit 3, the ACE Report, as NSIA and NSOG). Prior to this forced outage event, the Nuclear organization identified single point vulnerabilities (critical components that could cause a trip of, or equivalent detrimental function to, a unit) as per the station [Oconee] applicable plant procedures. The Nuclear organization placed labels on the single point vulnerabilities, or SPVs, to alert others to their location. The Nuclear organization also required a work order and specific risk screening for any work performed within two feet of any SPV. Witness Metz testified that the SPV "two feet limit" procedure was about six months old at the time of the unit trip and had not been delivered to the Transmission organization, even though Transmission personnel worked on or near equipment designated as SPVs. Witness Metz stated that the failure of the Nuclear organization to properly inform the Transmission organization prevented the RTs (who were members of the Transmission organization) from understanding the potential ramifications or risks of working on or near equipment designated as SPVs. Thus, as discussed in the ACE Report, the RTs did not understand the meaning of the single point vulnerability signage posting that was placed by the Nuclear organization in the relay house/building and specifically on PCB-58. In addition, because the RTs were not familiar with the procedure, the work order and special risk assessment required under station procedure was not performed. Witness Metz asserted that had the procedure been understood and followed, or had the RTs taken the time to question the existence and purpose of the special signage, it is reasonable to presume that the risks associated with working near PCB-58 would have been identified and steps taken to avoid erroneously actuating PCB-58, thus preventing the Unit 3 outage from occurring. Tr., pp. 110-112, 135-136.

According to witness Metz, a second contributing factor was a failure to properly risk screen the work to be performed by the RTs. According to Company procedures, all work within two feet of an SPV required a work order and specific risk screening. However, prior to the RTs performing the test or work on PCB-57, the "station did not identify and properly risk screen this work," as it was within two feet of PCB-58, a labeled SPV. (See Metz Confidential Exhibit 3, p. 14 showing PCB-58 and PCB-59 labeled SPV and their proximity to PCB-57). Station personnel failed to follow these prescribed procedures. The Company acknowledged this failure in a response to a Public Staff data request, attached as Exhibit 4 to witness Metz's testimony. Station personnel should have briefed and then worked with the RTs to prevent interaction with other components in the electrical cabinet. Tr., pp. 110-111,128-129. In his summary, witness Metz characterized these failures as organizational mismanagement.

Witness Metz further testified that the lack of understanding regarding SPVs was compounded by a third factor or contributing event. He stated that multiple indicators demonstrate that the RTs did not fully appreciate the risk associated with their task and they failed to use required Human Performance (HP) procedures and practices to effectively mitigate risk. The ACE Report indicates that the RTs should have used HP barriers to mitigate risk, and more importantly, the RTs acknowledged in interviews that they knew that they should have been using them. "[T]he technicians did understand that they were working near the generator breakers (trip sensitive components as indicated on the label) and that a BFR on a generator breaker would open both Unit 3 generator breakers. It is expected that additional barriers would have been used to ensure the correct component was worked. This was not done."[1] Further, an excerpt from the Cause Analysis (CA) Report states as follows (emphasis added):[2]

> Incomplete pre-job brief
>
> > Did not capture crew make-up (RT 2 typically works with different crew).
> > Subsequent pre-job briefs were not documented/performed (RT3 left and returned no pre-job brief documented, no pre-job brief to refocus when asked to re-test relay).
> > <u>Roles and responsibilities were not defined</u>.
> > <u>Had "N/A" under inadvertent operation section</u>.
> > No additional Hazards were identified on form.
>
> Critical Thinking/Protection Circuit Procedure form was filled out the morning of the job.
>
> Critical Thinking/Protection Circuit Procedure form was <u>not properly filled out</u>, the front page was not completed. <u>The critical thinking questions, critical thinking checklist, and identify additional traps section were left blank</u>.
>
> Critical thinking/Protection Circuit Procedure was vague and lacked detail. The procedure did not have the critical steps identified. The Relay Technicians were not using circle and slash for place keeping (they were using an electronic version of circle and slash) nor were there time stamps on their activities.
>
> <u>Peer check was not used (crew stated they used it during the day on this job, just not at the time the error occurred). It was a known expectation to use it</u>.
>
> <u>HP Toolkit was not used-crew discussed and decided it was more of a hindrance than (sic) a help (barriers would be in the way, clips could pull wires out). Crew felt the HP Toolkit was not applicable.</u>
> <u>Self-check was not used by RT3 placing the test leads</u>.
> Improper 3-way communication was utilized.

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[1] Metz Confidential Exhibit 3, ACE Report, p. 14.

[2] Metz Confidential Exhibit 2, CA Report, pp. 5-6.

> There was no questioning attitude from the crew on what "Single Point of Vulnerability" meant on the front of the panel below the relay they were working on.
>
> The crew had an inaccurate risk perception of the importance of correction component identification. They were working above the BF relay for a Unit 3 breaker.
>
> Human Performance Factors
>
> Assumptions:
>
> > RT3 assumed he was on the correct relay.
> > The crew assumed HP tools were a hazard and decided not to utilize them.
>
> Roles and responsibilities were not clearly defined in the pre-job brief. They also changed. RT2 made the test lead connections the first time and RT3 made the test connections the second time.
>
> Delays: There were delays in the work due to the relay not testing properly.
>
> Inaccurate risk perception: The Relay Crew did not see the risk in getting on the wrong component and that the wrong component could be the Unit breaker BF relay.
>
> Relay Technicians did not stop the job when the commissioner asked them to continue testing late in the day after they removed the test leads from the relay they were testing.[1]
>
> The rear of the PCB58 and PCB59 BF relays in panel MF3 are not labeled with Single Point of Vulnerability labels.

Tr., pp. 112-114.

Witness Metz explained the importance of HP tools or practices. HP tools or practices are actions taken to mitigate known or identified risks prior to performing work in areas that are known to have vulnerabilities. Such risk mitigation can include: (1) creating unified procedures; (2) a positive culture and work environment; (3) identifying appropriate tools for use on a particular job; (4) generalized and risk specific personal protective equipment; and (5) implementation of a feedback loop for improving the overall process. Each step in the risk mitigation process is equivalent to creating an additional layer of protection. It is critical to determine if and when there are enough steps in place to prevent certain unintended actions or consequences, or to determine

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[1] "The crew did not hold a pre-job brief to refocus. ... RT3 did not allow enough time for confirmation of the 3 way communication before placing the test leads on the incorrect terminal points." Metz Confidential Exhibit 2, CA Report, p. 3.

if any barriers already in place make the overall task or job either overly burdensome, or create new risks. In summary, the intent of Human Performance tools is to create a sufficient number of barriers to prevent discrete events from causing unwanted or unrecoverable actions (e.g., in this particular instance, connecting test leads to the wrong piece of equipment and causing Oconee Unit 3 to trip). Tr., pp. 116-117.

Witness Metz testified that in this case, just one week prior to the actions that resulted in the forced outage, two of the three RTs attended a meeting where "HP tool use being mandatory was discussed... The Relay Technicians stated that they knew it was an expectation to use the toolkit."[1] [emphasis added] According to witness Metz, it is not reasonable to have attended a meeting emphasizing the "mandatory" use of HP tools, and then arrive at a conclusion that "HP toolkit [use] was not applicable"[2] through self- or group-determination absent a minimum of supervisory notification and on-site representation to peer check or independently assess the risks involved. He testified that the RTs deliberately and knowingly failed to use DEC's human performance tools and that in his opinion, had these important tools been used properly, the outage could have reasonably been avoided. Tr., pp. 117-118.

Duke Energy's Human Performance Standard Tools were stipulated into evidence at the hearing as Public Staff Metz Exhibit 5. Tr., p. 133; Official Exhibits, p. 131. This exhibit lists Duke's 13 human performance tools, what they are for, and how and when they are to be applied. According to this list, the "Pre-Job Brief" is a "[d]eliberate meeting of job participants that focuses on everyone's understanding of job scope, requirements, hazards, risks and defenses." As described above and on page 9 of the CA Report, the Oconee outage Pre-Job Brief was vague, and several sections were not filled out or were improperly filled out. According to the HP Incident Form located on page 22 of the CA Report, the RTs did not use nine of Duke's 13 standard HP tools, including: 2-minute drill, self-check, 3-way communication, peer check, concurrent verification, independent verification, procedure use and adherence, qualify, validate, verify, and stop when unsure. The reviewers of the RTs' actions concluded that those nine HP tools were needed and represented a latent organizational weakness in procedures and documents.

Witness Metz testified that the evidence shows that the RTs understood there were risks associated with their work and knowingly disregarded the human performance tools that would have mitigated that risk. The Company acknowledged in response to a Public Staff data request that RTs understood they were working near generator breakers and that the breakers could impact unit operations. However, the RTs discussed the human performance tools and did not use human performance barriers because they had performed the work before and discounted the risk, and "because they were afraid they would be in the way of their work."[3] Tr., p. 118.

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1 Metz Confidential Exhibit 2, CA Report, pp. 5-6.

2 Metz Confidential Exhibit 2, CA Report, p. 5.

3 Metz Confidential Exhibit 2 CA Report, p. 2. The CA Report specifically states, "The wire identifying clips were not used because they were afraid they would pull the wires out of the crimped connection if they did not open the clip all the way when removing them."

Witness Metz asserted that while the work area[1] could be somewhat disorienting to an untrained individual or someone not familiar with internal cabinet wiring, based on his experience and professional opinion, neither the wiring nor the configuration layout of the terminal blocks and wire terminations is uncommon, but are typical of an industry norm. According to witness Metz, the Company confirmed in response to a data request that it is common practice for breaker failure relays to be in the same cabinet for multiple PCBs. In other words, the presentation of the equipment under test was not extraordinary and should not have caused particular confusion for the Company's experienced RTs. Witness Metz asserted that irrespective of worker experience, it is without question that in circumstances similar to the pictures shown in Metz Confidential Exhibit 2, the CA Report, pages 14-15, care must be taken to ensure that the planned and necessary work is being performed on the correct equipment without interfering with other equipment. He asserted that the failure of the RTs to exercise proper care by using human performance practices to ensure that they were working on the correct relay (in the absence of labeling on the rear of the cabinet) is not consistent with fundamentally sound work practices. He reiterated that in his opinion, the outage could have reasonably been avoided had the Company personnel utilized the human performance systems and practices put in place to prevent errors. Tr., pp. 118-119.

Witness Metz testified that it is not the Public Staff's position that all human performance errors are preventable or that the Company should be held accountable for anything less than perfection in the operation of its nuclear plants. During the test year for this proceeding, just as with any fuel proceeding, planned and unplanned outages occurred. Witness Metz stated that as someone with significant experience working in not only the nuclear industry, but in industrial environments in general, he fully understands that operational events happen and that perfection cannot occur as long as the human element is involved. On the other hand, some events, when Company management or personnel do not follow required procedures or do not use due diligence, are clearly preventable. He asserted that the outage at Oconee Unit 3 is one such outage. As stated in the ACE Report, "<u>The human performance practices by the Transmission Personnel were a last line of defense. The failure of this last line of defense allowed the event to occur</u>. However, station defenses that were either missing, inadequate or not used also failed to prevent this event." [emphasis added] Intra-Company organizations did not properly communicate, coordinate, or take notice of Company procedures put in place for the very purpose of mitigating risks associated with SPVs that could cause the shutdown of a generation unit. He asserted that the Company is ultimately responsible for (1) ensuring that its employees are properly trained and made aware of Company policies and procedures and (2) that its employees perform work that properly accounts for known risks that may result in a plant shutdown or damage. Not holding DEC accountable for these types of outages results in ratepayers bearing the full cost of more expensive replacement power. According to witness Metz, the Company's failure to notify the Transmission organization of procedures related to SPVs and to risk screen the RTs' work is Company mismanagement.. In addition, there were breakdowns of Company procedures on several levels; moreover, there was a deliberate failure to use established human performance practices to mitigate risk. Therefore, this was a reasonably preventable outage, and as between the Company and ratepayers, the Company should be responsible for the additional costs. Tr., pp. 115-116.

[1] Metz Confidential Exhibit 2, CA Report, pp. 14-15.

During Commission questioning, witness Metz was asked about several hypothetical examples of exemplary actions of Company personnel that resulted in preventing an outage and asked whether it would be appropriate to offset the Oconee outage costs at issue in this case with the costs avoided due to the hypothetical actions of the employees. Witness Metz testified that he would still recommend that the Commission exclude the replacement power costs of the Oconee outage. Tr., pp. 138-139, 142. He testified that even if the facts were to show generally that the capacity factor for DEC's plants were well above the NERC average and that DEC's plants are better constructed, better maintained and were able to avoid forced outages better than anybody else, he would still recommend a disallowance for the Oconee outage costs. He stated that based on the General Statutes and Commission Rules, if the costs are imprudent or unreasonable, they should be disallowed and the ratepayers should not have to pay for them. Tr., pp. 139-140. He also testified that based upon his personal experience of working in electrical control cabinets, it is more likely than not that had the RT's used the HP Toolkit, the incident would not have happened. He also stated that if he were a team or group leader for the relay technician group performing work in this particular case, a level of management oversight for him would be reasonable and likely as he planned for and then delegated work activities, and that he would expect to be held accountable for the workers and the work actions that take place under his oversight. Tr., pp. 143-144.

DEC witnesses Capps and Rogers, from the Nuclear and Transmission organizations within the Company, respectively, testified on rebuttal regarding witness Metz's testimony that the outage at Oconee 3 was "reasonably avoidable" and that the resulting replacement power costs should be disallowed. They testified that the evidence shows that the outage resulted from an isolated incident in which well-trained and seasoned employees made errors in judgment despite reasonable and prudent training and processes implemented by Company management. They noted that witness Metz testified that he is not holding the Company to a standard of perfection. However, they testified that witness Metz's recommended disallowance of replacement power costs arising from an isolated, non-recurring outage that was the result of reasonable but ultimately flawed judgment, despite the fact that witness Metz has identified no evidence of flaws in the Company's overall policies and procedures and despite the fact that the performance of DEC's nuclear fleet has far exceeded industry average, effectively does hold the Company to a standard of perfection. Tr., pp. 15-151.

Witnesses Capps and Rogers stated that witness Metz appears to base his recommendation on the fact that the outage was "reasonably avoidable". In their view, witness Metz's standard for disallowance is not in accord with Commission precedent. Instead, they testified that the Commission's prior decisions have established that the key issue is whether management decisions were made in a reasonable manner at an appropriate time on the basis of what was reasonably known or should have been known at the time. They believe that Commission precedent establishes that the focus of the Commission's review should be on the decisions of management and not on the decision of a particular employee in performing a particular task. Tr., pp. 150-151.

Witnesses Capps and Rogers stated that in this case, witness Metz fails to offer evidence sufficient to establish that the Company's management decisions were unreasonable given what was known at the time. To the contrary, the quality of the Company's management is demonstrated first and foremost by the overall performance of its nuclear fleet and this level of performance is simply not achievable without an overall culture of excellence. The training, standards and practices put in place by DEC management are reasonable and have directly resulted in exceptional overall performance that has benefited all customers. Tr., p. 151.

More specifically, witnesses Capps and Rogers testified that the Company's ongoing implementation of the SPV program is a prime example of its focus on continued improvements and the Company is proud of the program as implemented to date. The focus on the SPV program from its inception has been on the Nuclear organization and the Company has continued to evolve and develop the program – moving from an initial focus on equipment reliability programs to a more broad focus on reliability of components and eventually expanding beyond the plant property into the switchyard. However, they contend that penalizing DEC for not implementing the SPV program into the Transmission organization would serve as a disincentive to the principles of continual improvement that have always guided the Company. Moreover, they testified that the Company has been productive in addressing switchyard interface issues through other avenues and has a demonstrated track record of success in this area, working with industry organizations like the Electric Power Research Institute, the Institute of Nuclear Power Operations (INPO), and the North American Transmission Forum. Tr., pp. 151-152.

Witnesses Capps and Rogers cited the use of the HP tools in the Transmission organization as another example of continual improvement. They stated that Company management has implemented an HP program that is in line with industry best practices and has contributed to the overall successful performance of its nuclear fleet. Further, they testified that even if the Commission chooses to look past the actions of management and specifically examines the particular decisions of the individual employees in this instance, they contended that the evidence shows that witness Metz oversimplifies the use of HP tools and ignores the "on the ground" reality that the Company's personnel are expected to utilize discretion in applying the HP tools based on each situation. In this case, witnesses Capps and Rogers testified that the RTs in question did utilize certain HP tools but also exercised discretion in the use of the HP tools in a manner that was not without basis in experience, but ultimately not in accord with the standards set by management. In their own opinion, this incident highlights the fact that, from time to time, errors in judgment will occur on the part of the individual employees despite adequate training and standards. However, such errors do not equate to imprudent management that would serve as a basis for cost disallowance in accordance with the Commission's precedents. They testified that the Company's management made reasonable decisions in a reasonable manner and at an appropriate time based on what was reasonably known or should have been reasonably known at the time, and the isolated, non-recurring errors in judgment of certain employees should not serve as a basis for disallowance. Tr., pp. 152-153.

Witnesses Capps and Rogers noted that witness Metz expressly acknowledged that he is not alleging that DEC has inadequate policies or cultures, which they believe is obvious given the excellent operational performance of DEC's nuclear fleet that is not achievable without efficient and prudent management. They explained that DEC's exemplary performance is attributable to DEC's dedicated and highly trained workforce. In the Nuclear organization, formal training programs are established and accredited by the INPO and the National Nuclear Accrediting Board. When performance fails to meet expectations, the Nuclear organization completes rigorous self-critical investigations to identify enhancements to reduce and minimize future challenges.

Every opportunity to learn from internal and external events is embraced as the Nuclear organization strives for continuous improvement. Similarly, in the Transmission organization, RTs attend a rigorous technical program that includes a four-year initial training program consisting of 200 plus hours of classroom, online, and field training, annually. RTs are also required to attend a minimum of 20 hours each year of continuing education to maintain and improve technical and human performance skills. Tr., pp. 153-154.

Witnesses Capps and Rogers testified that the Company is continually engaged in efforts to improve its operations and maintenance practices in order to achieve even greater levels of safety and reliability. As the Company identifies avenues of improvement, it seeks to implement such improvements in a disciplined and thoughtful manner. However, considering the breadth and complexity of the work performed within the Nuclear and Transmission organizations, identified areas of improvement cannot, in every instance, be addressed immediately or in a comprehensive manner. They contended that penalizing the Company for implementing an identified improvement incrementally serves as a disincentive for continual improvement and, instead, encourages the Company to implement improvements only when it can be sure that it is ready to do so comprehensively across every organization. The interest of customers is best served when the Company is encouraged to pursue continual improvement even where such improvements can, over time, be more efficiently and comprehensively implemented. Tr., pp. 154-156.

They noted that witness Metz focuses repeatedly on whether the outage could have "reasonably been avoided", but witness Metz himself indicated that he had not identified any "inadequate policies" or any failure of DEC to "promote and encourage operational excellence overall." They testified that virtually all outages that involve some form of human error could, in some sense, have "reasonably been avoided." However, they contended the evidence shows that the Company's overall management of the nuclear fleet during the test period was reasonable and prudent. Tr., pp. 156-157.

Witnesses Capps and Rogers addressed the challenges of human error in the context of nuclear operations and maintenance activities and noted that, on a daily basis, highly skilled and trained technicians perform thousands of challenging technical tasks to ensure safety and reliability of the nuclear fleet. While management puts structures and methodologies in place to guide and inform the performance of such tasks, it is ultimately the Company's personnel that must execute each task. They stated that "on the ground" reality is that humans will occasionally make error in judgment despite even the most prudent and vigilant management efforts, a fact that was acknowledged by witness Metz. However, they testified that does not mean that DEC expects forced outages caused by human error. To prevent human errors, witnesses Capps and Rogers explained that both the Nuclear and Transmission organizations have formal human performance training curriculum and human performance standards that are reinforced and verified by formal peer and management observations. Lower level human performance challenges, often classified as "near misses," are aggressively reported, tracked, and shared across these organizations. Working with industry groups, both these organizations leverage not only internal learnings, but learnings across the industry. Procedures and processes are designed with a keen focus on identifying and mitigating human error traps. Id.

ELECTRIC – MISCELLANEOUS

Witnesses Capps and Rogers testified that the Company's number one priority in every instance is safety. However, the Company also continually seeks to balance two additional primary objectives: (1) achieving extremely high levels of reliability and (2) minimizing costs for customers. Witnesses Capps and Rogers noted there is an unavoidable relationship between costs and reliability. Pouring more resources and processes into plant operations will, all things being equal, generally lead to higher levels of reliability. In spending more money, the Company could deploy even more resources and processes that would likely allow the Company to limit even further the already small number of human errors that could occur at its nuclear facilities. However, in their opinions, the Company's performance metrics, combined with its low operating costs, demonstrates that the Company is striking the right balance. Tr., pp. 158-159.

Regarding witness Metz's heavy reliance on the Company's RCA and ACE reports, witnesses Capps and Rogers stated that such reports are, by design, hindsight-based and highly self-critical in nature and are intended to identify every direct and contributing cause of an incident, along with all potential avenues for improvement. These reports are not designed to assess whether the actions of management were reasonable and prudent given what was known at the time. However, in relying heavily on these reports, witness Metz is not necessarily able to obtain or appreciate the broader context of the outage and decisions and events that lead to the particular outage. For example, witnesses Capps and Rogers explained that this outage involved so-called switchyard interface issues. Such challenges arise where two distinct, highly skilled Nuclear and Transmission organizations are working in a physical location in which their respective assets overlap. Each organization has their own practices, policies, and procedures. Switchyard interface issues challenge utilities across the industry and there are industry working groups and other resources that specifically focus attention on how to best anticipate and solve switchyard interface issues. The RCA and ACE reports are not intended to give the larger, industry context for these outages and therefore do not always provide detail regarding these broader industry challenges. But the fact that the industry as a whole is facing these issues is an important piece of evidence that should be considered is assessing whether Company management's actions were reasonable. Had witness Metz explored this issue further and looked beyond these reports, he would have discovered that the Company's switchyard interface structures and practices have been specifically reviewed by an industry working group and found to be extremely high quality relative to the industry. In the opinion of witnesses Capps and Rogers, it is unreasonable to make an assessment of the prudence of the Company's management actions without understanding the context of the issue and the larger state of the industry as it relates to switchyard interface issues. They stated that the Commission should consider that the Company has implemented structures and processes that are found to be exemplary relative to the industry when assessing the reasonableness of Company management actions. Tr., pp. 159-161.

With respect to the two RTs involved in this incident, witness Rogers stated that they had completed every aspect of the Company's specially tailored training program for Transmission RTs. This comprehensive technical training includes both theoretical and application-specific training and is conducted in a variety of settings over the first few years of employment. RTs also participate in a weekly meeting that is designed to ensure the latest policies and programs are communicated in a timely manner and that applicable training is provided to foster continual improvement. Field supervisors are expected to spend a significant portion of time observing and coaching technicians in the field. RTs are typically paired such that one senior technician can bring the benefit of practical, real world experience to each task and provide continuous training specific to the work at hand. The senior technician on this Preventive Maintenance team, which was specifically focused on performing this type of work, had over four years experience as a transmission relay technician and had performed tasks similar in nature more than two hundred times. The other technician has received similar training and had performed similar tasks over one hundred times. During the twelve months prior to the outage incident, these two RTs had completed approximately 350 work orders and no adverse trends or findings had been detected and there was no history of performance challenges. Tr., pp. 161-162.

Witnesses Capps and Rogers also testified that the Company does not have any history of repeated errors involving work in the switchyard and noted that witness Metz made no such allegation. In fact, there has not been another outage at a DEC nuclear plant involving switchyard interface issues in over a decade, despite countless maintenance tasks occurring in the switchyard. Witness Capps testified that it was his understanding that the Commission has expressly held that a repeated error is a key indicator of imprudent management. Tr., pp. 163-163.

Witnesses Capps and Rogers also explained that an SPV is a critical component whose failure would directly cause an automatic or manual trip of a reactor or turbine. Noting that witness Metz alleges that the failure of the Nuclear organization to properly inform the Transmission organization of SPV procedures prevented the RTs from understanding the potential ramification or risks of working equipment designated as SPVs, witnesses Capps and Rogers stated that the implementation of the SPV program has been an evolving process in which the Company has gradually expanded the scope of the program while continually refining the specific processes and methodologies. Most recently, following a 2016 event, the Company developed a procedure to guide work requirements within two feet of equipment identified as a SPV. Efforts to implement the SPV program in the Nuclear organization was reasonable and they again contended that it would not be a good regulatory policy to require that such improvement be implemented perfectly or not at all. In their opinion, DEC's implementation of the SPV program was reasonable. Tr., pp. 163-164.

Regarding the role of the Switchyard Coordinator, they stated that this position is responsible for coordination of transmission maintenance activities with the nuclear plant for work affecting the nuclear switchyard, which includes providing oversight, as required, of transmission field work activities to ensure that plant work requirements and good work practices are being maintained. In this case, witnesses Capps and Rogers stated that there were a number of factors that influenced the Switchyard Coordinator's assessment of risk and decision including the facts that the particular RTs involved in this incident were well-trained and experienced and that similar relay testing has been performed successfully many times. In light of these factors, the Switchyard Coordinator prioritized other responsibilities over providing oversight to the relay work. They justified that the reality is that plant personnel must make judgment calls regarding how best to allocate available resources and such decisions are inevitable as the Company balances the goals of minimizing costs and maximizes reliability. The Switchyard Coordinator was in fact expressly charged with providing oversight only as required. The error in judgment of the Switchyard Coordinator was based upon the fact that an SPV was within the area of work to be performed, but again highlights the fact that this outage resulted from less than optimal, though not wholly unreasonable, judgments of particular employees. Tr., pp. 165-167.

Witnesses Capps and Rogers also testified that the Nuclear cause analyses typically assesses whether internal or external operating experience (OE) was available that if utilized could have allowed the Company to avoid the event. The Nuclear ACE concluded that his event was not OE Preventable. They stated that this suggests that this event was somewhat unique and therefore not foreseeable. Id.

Witness Rogers testified that "HP tools" is a general term that refers to a whole suite of tools and techniques. In the Transmission organization, HP tools consist of physical HP barriers and HP techniques. The physical HP barriers include various markers and flags that can be utilized to physically identify specific work areas for various purposes. HP techniques are more general principles and practices used to ensure quality work. He stated that DEC's efforts to implement HP programs in the Transmission organization are actually on the forefront of the industry. However, there is not a standard set of HP tools that must be utilized on every assignment. Both the physical tools and techniques must be adapted to the specifics of each scenario. It is the expectation within the Transmission organization that the technicians assess each situation to determine what HP tools are appropriate for the task at hand in light of the specific tasks being performed and the strengths and weaknesses of the technicians performing the tasks. Witness Rogers stated that these RTs had been trained in use of the HP tools; however, the HP toolkit of physical barriers provided to the RTs was relatively new at the time of the event. Therefore, the RTs were likely still adapting to the toolkits and determining how to use the tools most effectively. Regarding witness Metz's allegation that the RTs "failed to use required HP procedures and practices to effectively mitigate risk", witness Rogers stated that this allegation oversimplifies the use of HP tools by implying the use of each and every one of the HP tools is mandatory in each and every case. The RTs did understand that, in general, use of the HP tools is mandatory, but also understand that use of the HP tools is not a rote process and requires the use of discretion and judgment on the part of employees. Therefore, he contended that it is an overstatement for witness Metz to assert that the RTs "deliberately and knowingly failed to use DEC's human performance tools." Further, witness Metz's testimony does not make clear that the RTs did actually utilize a number of HP tools at the time of the incident, including: , pre-job brief, procedure use, place keeping techniques, stop when unsure, and three way communication. The fact that the RTs used some but not all of the HP tools is significant in witness Rogers' opinion because it demonstrates that these employees were trained in the HP tools and understood their importance. Tr., pp. 166-168.

Witness Rogers noted that the RTs could have used flagging or identifying clips to identify the correct relay but choose not to do so. He noted that witness Metz specifically highlights this failure as a part of the basis for his recommendation. According to witness Rogers, the RTs elected not to utilize the physical HP barriers due to fear of inducing an inadvertent trip or outage when placing or removing the clips. Witness Rogers stated that it was not completely unreasonable for the RTs to conclude that use of the clips was risky because there are many examples of incidents arising from inadvertent bumping or disturbance of a relay including while installing HP barriers. Utilizing the clips could have heightened the potential for just such an occurrence. Ultimately, witness Rogers believed that that the RTs should have used the clips, but their decision was grounded in a true risk. In his opinion, it is not possible for prudent management to completely prevent mistakes like this from happening, even when Company management establishes adequate training and related protocols. However, he stated that such isolated instances should not be equated to imprudent management that would give rise to a disallowance, particularly in this context where customers have received immense benefit in the form of lower fuel costs from superior performance resulting from Company management's efforts. Tr., pp. 168-169.

Witness Rogers added that these employees had performed tasks similar in nature many times without previous error. In fact, these RTs had performed the relay test on the correct relay several times during the same day. While management strenuously encourages employees to follow established protocols no matter how familiar a task is or how many times it has been successfully completed in the past, the reality is that recurring tasks can often lead employees to human error. However, he stated that the occurrence of such incidents from time to time does not indicate any imprudent management. Tr., pp. 169-170.

According to witness Rogers, other factors impacted the RTs and contributed to the error. The RTs encountered a technical hurdle while completing the relay testing that they did not expect. As trained and in accordance with HP tools, the RTs stopped and called technical support to seek further guidance. Witness Rogers stated that the frequent starting and stopping of the work, the additional mental distraction and the unexpected duration of the task contributed to the circumstances resulting in the error. Tr., pp. 170-171.

Finally, witnesses Capps and Rogers commented on witness Metz's statement that DEC is "ultimately responsible for (1) ensuring that its employees are properly trained and made aware of Company policies and procedures and (2) that its employees perform work that properly accounts for known risks that may result in a plant shutdown or damage." They stated that DEC agrees with the first portion of witness Metz's statement and they believe that in this instance, the employees were properly trained in all aspects as set forth in their testimony. However, witnesses Capps and Rogers testified that the second portion of witness Metz's statement once again mischaracterizes the Commission's standard and appears to impose a standard that is more akin to one of perfection. According to them, the Commission's prudence standard focuses on the decisions of management and not on the discrete, individual decisions of each employee. Furthermore, they stated that the Commission has expressly stated that perfection is not the applicable standard. Yet, witness Metz's standard – that all employees at all times should perform work in every instance in a manner that "accounts for known risks" – is in essence a "back door" perfection standard. Tr., p. 171.

COMMISSION DISCUSSION

The fuel adjustment statute, N.C. Gen. Stat. § 62-133.2(d), provides that the burden of proof as to the correctness and reasonableness of the charge and as to whether the cost of fuel and fuel-related costs were reasonably and prudently incurred is on the utility, and the Commission shall allow only that portion of fuel costs prudently incurred under efficient management and economic operations. Under N.C.G.S. § 62-133.2(d1), the Commission is required to establish standards with which to measure management efficiency in minimizing fuel costs. Commission Rule R8-55(k) provides that for purposes of determining the EMF rider, a utility must achieve either (a) an actual system-wide nuclear capacity factor in the test year that is at least equal to the national average capacity factor for nuclear production facilities based on the most recent 5-year period available as reflected in the most recent NERC Generating Availability Report, appropriately weighted for size and type of plant or (b) an average system-wide nuclear capacity factor, based upon a two-year simple average of the system-wide capacity factors actually experienced in the test year and the preceding year, that is at least equal to the national average capacity factor for nuclear production facilities based on the most recent 5-year period available as reflected in the most recent NERC Generating Availability Report, appropriately weighted for size and type of plant. If a utility does not achieve either standard, a presumption is created that the utility incurred the increased cost of fuel and fuel-related costs imprudently, and a disallowance of the increased costs is appropriate.

As previously noted, the Company's nuclear fleet achieved a capacity factor above the NERC average, rendering the rebuttable presumption of imprudence under Commission Rule R8-55(k) inapplicable. Thus, based upon the provisions of the fuel adjustment statute, the question before the Commission is whether the Company has met its burden of proving that the replacement power costs resulting from the Oconee Unit 3 outage in July 2017 were reasonable and were prudently incurred under efficient management and economic operations.

The Commission has stated the general prudency standard as follows:

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

78 North Carolina Utilities Commission Report, 238 at 251-52 (1988). In its Order Deciding Contested Issues and Requiring Compliance Filing (DENC Order) entered January 25, 2018, in Docket No. E-22, Sub 546, the Commission set forth three general guidelines for determining whether a utility's actions or omissions were imprudent:

1. Whether the utility's actions were reasonable based on the information known to the utility at the time.

2. Whether the utility's actions were reasonable based on the information that the utility reasonably should have known at the time.

3. Whether there were repeated errors that the utility failed to discover due to inaccurate record keeping or other deficiencies, or failed to correct in a reasonable time or manner.

DENC Order, p. 9. In determining whether the utility's actions or omissions were imprudent, the Commission in the DENC Order looked at whether the outages could have reasonably been prevented by the Company given the information it knew at the time, and whether the outages resulted from unreasonable or imprudent management. DENC Order, p. 13. The Commission also considered whether applicable procedures were followed. DENC Order, pp. 14-15. In the DENC Order, the Commission undertook a review of the specific facts underlying the outages at issue. In investigating the prudence of DENC's actions that led to the outages, Root Cause Evaluations, or reports that document a utility's investigation of the causes of and contributing factors to specific outages, were considered. DENC Order, p. 12. The Commission ultimately concluded that the DENC outages could not have reasonably been prevented, and the replacement power costs associated with the outages were reasonably and prudently incurred under efficient management and economic operations. DENC Order, pp. 13-17. However, the Commission encouraged the Public Staff to continue presenting its concerns about utility operations to the Commission. DENC Order, p. 19. In the Commission's June 22, 2018 Order Accepting Stipulation Deciding Contested Issues, and Requiring Revenue Reduction in Docket No. E-7, Sub 1146, (DEC Order), the Commission found that challenging prudence "requires a detailed and fact intensive analysis." DEC Order, p. 258.

The Oconee Unit 3 July 2017 outage lasting approximately 30 hours resulted in approximately $434,000 of additional purchased power costs on a North Carolina retail jurisdictional basis. The issue in this case resulted from a negligently conducted test in the plant's switchyard. Overall, during the test year and in years prior to the test year, DEC's nuclear fleet has performed well in excess of the NERC average capacity performance metrics against which the Commission and the nuclear industry assess performance of nuclear units. In fact, the evidence shows that during the test year, DEC's nuclear fleet achieved the second best annual generation in the Company's history. The Public Staff argues that irrespective of the level of overall performance of DEC's nuclear fleet, the Commission should impose a $434,000 replacement power cost disallowance for the Oconee outage. DEC argues that the negligently performed test should not be attributable to mismanagement, constituting imprudent management, and any outage in the nature of the one at issue, no matter the duration, no matter the amount of additional purchase power costs, and irrespective of the level of overall performance at the nuclear fleet, should be borne by the ratepayer.

The Commission finds both positions flawed in the context of the facts of this case. The unrefuted evidence is that DEC's employees performing the testing tasks made mistakes. Further, the task was not one performed by a lineman on a distribution transformer resulting in a temporary outage of a homeowner or two. The test was to ensure proper operation of the power circuit breaker relay for a transmission line in the nuclear plant switchyard. The test was performed on the wrong relay, resulting in the shutdown of the generation unit. On the other hand, the Company has implemented structures and processes that are found to be exemplary relative to the industry when assessing the reasonableness of Company management actions and the training, standards and practices put in place by DEC management have directly resulted in exceptional overall performance that has benefited all customers. The overall sound practices and good management performance demonstrated by DEC is a fact the Commission cannot ignore.

The Commission determines based on the particular facts of this case not to accept the Public Staff recommended adjustment. DEC's overall nuclear performance in comparison to the NERC nuclear average performance was such that the Commission concludes, as discussed more fully below, that the errors of DEC's employee are outweighed and offset by DEC's overall operational decisions that on balance worked to the advantage of the ratepayer. If, hypothetically, DEC's performance would have been no better than the NERC average and the outage would have lasted longer and the purchased power costs would have been at the multimillion dollar level, with a material impact on customers' bills, or other factors affected the outcome, the Commission's decision very well could be different. A nuclear plant outage resulting from negligent testing by a DEC employee within the plant's switchyard cannot result in significant purchase power costs to be borne fully by ratepayers based solely on DEC having in place procedures that, if appropriately followed, would have avoided the outage. DEC's management bears responsibility for hiring employees who can follow instructions when performing important tasks.

As discussed below, the gravity of the conduct, the level and sufficiency of management supervision and procedures, the qualifications of employees, the findings in the reports assessing the contributing factors to the outage, the extent to which overzealous use of RCEs might impede thorough use of them, the overall nuclear capacity factors and extraneous factors contributing to them, for example, are all relevant. In rendering this decision, the Commission is not saying that every time the Company's nuclear fleet performance exceeds the NERC average by eight percentage points and the excess purchased power costs are only $434,000, no disallowance will be approved. Each case must be decided on its own merits. The Commission observes that the facts with respect to each usage period and each outage tend to be *sui generis* and must be analyzed and addressed independently. In establishing fuel charge adjustments, the Commission is exercising its legislative, ratemaking authority. As such, its decisions are not *stare decisis*.

The Commission determines that in cases such as these excessive emphasis easily can be devoted to presumptions and burden of proof. Seldom, if ever, will they be decided on an absence in the record of evidence of what the Company at issue did, the reasons for its actions and the context in which its actions were taken. Usually, as here, the cases are decided on the merits after a careful review of substantial evidence produced on behalf of parties filing direct and responsive testimony. While the Company would be remiss in relying solely on the fact that its performance exceeded the nuclear average during the period in question, when evidence of negligence or imprudence is presented, the statutes in Chapter 62 and Commission Rule R8-55 are not a "heads, I win, tails, you lose," so that failure to meet the NERC average is probative but exceedance of the nuclear average is not. The utility always has the ultimate burden of proof and persuasion, and intervening parties must support their allegations with affirmative evidence. Just as evidence of failure to meet the NERC average is probative, however, evidence of performance exceeding the average along with other probative evidence of record is evidence that the Commission should consider in making its decision.

DEC concedes that the RT conducting the test in the Oconee switchyard made a mistake when he attached testing equipment to a relay on a live transmission line, rather than attaching the testing equipment to the relay that was intended to be tested, which was on a line not in use. However, DEC takes the position that there was no management imprudence because the RT was properly trained, and was provided with reasonable safety guidelines, but nonetheless failed to perform his job correctly.

The Public Staff takes the position that the RT failed to follow appropriate safety procedures, that DEC failed to properly ensure that it had communicated its safety procedures to the RT, and that the RTs' actions were negligence that constitutes imprudence by DEC. The Public Staff relies heavily on DEC's RCA and ACE reports. The Commission agrees that such reports are probative evidence, and the Commission gives them some weight. However, the Commission also notes that the RCA and ACE reports are made in hindsight, and that their main purpose is to assist management in identifying every possible contributing cause of an outage, and the ways in which it can be prevented in the future. As witnesses Capps and Rogers testified, the reports are not designed to assess whether the actions of management were reasonable and prudent based on what was known at the time.

Witness Metz described the test being performed and the cause of the Oconee outage as follows:

> [T]his involved connecting test equipment to a breaker failure relay (PCB-57). During the course of their work, a RT lost orientation of the location of the PCB-57 relay on which the tests were being conducted. This loss of orientation led the RT to misidentify the relay that was under test. As a result, the RT connected to and then tested the wrong relay (PCB-58, located directly below PCB-57), causing PCB-58 to operate. In other words, the RT connected test equipment to an operational, in-service relay, causing it to perform an unintended operation. This operation caused Oconee Unit 3 to "trip" offline, thus shutting down the unit.

Tr., pp. 109-110.

In essence, DEC's employee made a mistake. Employees sometimes fail to follow proper procedures that have been communicated to them in a reasonable manner, and, consequently, they make mistakes. However, every employee mistake resulting in a plant outage does not necessarily signify imprudence on the part of the utility. In the present case, the Commission gives substantial weight to the testimony of DEC witnesses Capps and Rogers regarding DEC's implementation of its safety guidelines and procedures. In particular, they testified that in the Transmission organization RTs attend a rigorous technical program that includes a four-year initial training program consisting of 200 plus hours of classroom, online, and field training. In addition, RTs are required to attend a minimum of 20 hours each year of continuing education to maintain and improve technical and human performance skills. With regard to DEC's Nuclear organization, they testified that formal training programs are established and accredited by the INPO and the National Nuclear Accrediting Board. In addition, the Commission notes that Public Staff witness Metz generally concurred that DEC had created training, safety procedures and HP tools sufficient to prevent the RT's mistake had they been fully utilized.

Further, the Commission gives substantial weight to the testimony of witnesses Capps and Rogers that DEC has implemented an HP program that is in line with industry best practices. They also testified that witness Metz oversimplified the use of HP tools and ignored the "on the ground" reality that the Company's personnel are expected to use discretion in applying the HP tools based on each situation. According to witnesses Capps and Rogers, in the present situation the RTs utilized certain HP tools, but also exercised discretion in the use of the HP tools in a manner that was not without basis in experience, though ultimately not in accord with the standards set by management. They attributed this to the fact that, from time to time, errors in judgment will occur on the part of the individual employees despite adequate training and standards. They further testified that the Company's management made reasonable decisions in a reasonable manner and at an appropriate time based on what was reasonably known or should have been reasonably known at the time. The Commission is not persuaded by the evidence that there was some reasonable additional training or safety measure that DEC could have employed that would have prevented the RT from making this mistake in identifying the proper relay to be tested.

Finally, as noted above, the Commission gives some weight to the fact that during the test year, and in years prior to the test year, DEC's nuclear fleet has performed well in excess of the NERC average capacity performance metrics against which the Commission and the nuclear industry assess performance of nuclear units. In fact, the evidence shows that during the test year, DEC's nuclear fleet achieved the second best annual generation in the Company's history. This record of high performance is probative evidence of DEC's prudence in operating its nuclear fleet in a reasonable and safe manner.

The Commission appreciates the detailed investigation of the Public Staff in evaluating the Oconee outage and encourages the Public Staff to continue investigating and presenting its concerns about utility operations so that the Commission might remain the ultimate decision-maker with respect to these types of issues. . However, in this instance the Commission declines to order the replacement cost disallowance as recommended by the Public Staff. Based on a preponderance of the evidence in this docket, the Commission finds and concludes that DEC implemented reasonable and adequate safety procedures to prevent the RT mistakes that were made at Oconee, and that DEC's actions were prudent based on the information that DEC knew, or reasonably should have known, at the time. As a result, the Commission concludes that the replacement power costs associated with this outage were reasonably and prudently incurred under efficient management and economic operations.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

Commission Rule R8-52(b) requires each electric utility to file a Fuel Procurement Practices Report at least once every 10 years and each time the utility's fuel procurement practices change. The Company's updated fuel procurement practices were filed with the Commission in Docket No. E-100, Sub 47A in December 2014, and were in effect throughout the 12 months ending December 31, 2017. In addition, the Company files monthly reports of its fuel and fuel-related costs pursuant to Commission Rule R8-52(a). Further evidence for this finding of fact is contained in the testimony of Company witnesses McGee, Grant, Miller, and Houston.

Company witness McGee testified that DEC's fuel procurement strategies that mitigate volatility in supply costs are a key factor in DEC's ability to maintain lower fuel and fuel-related rates. Tr., pp. 27-28. Other key factors include DEC's diverse generating portfolio mix of nuclear, coal, natural gas, and hydro; lower natural gas prices; the capacity factors of its nuclear fleet; the combination of DEP's and DEC's respective skills in procuring, transporting, managing and blending fuels and procuring reagents; the increased and broader purchasing ability of the combined Company; and the joint dispatch of DEP's and DEC's generation resources.

Company witness Grant described DEC's fossil fuel procurement practices, set forth in Grant Exhibit 1. Tr., pp. 36-40. Those practices include computing near and long-term consumption forecasts, determining and designing inventory targets, inviting proposals from all qualified suppliers, awarding contracts based on the lowest evaluated offer, monitoring delivered coal volume and quality against contract commitments, conducting short-term and spot purchases to supplement term supply, and obtaining natural gas transportation for the generation fleet through a mix of long term firm transportation agreements, and shorter term pipeline capacity purchases.

According to witness Grant, the Company's average delivered cost of coal per ton for the test period was $74.90 per ton, compared to $82.54 per ton in the prior test period, representing a decrease of approximately 9%. Tr., pp. 36-37. This includes an average transportation cost of $26.46 per ton in the test period, compared to $24.92 per ton in the prior test period, representing an increase of approximately 6%. Witness Grant further testified that the Company's average price of gas purchased for the test period was $3.65 per Million British Thermal Units (MMBtu), compared to $3.34 per MMBtu in the prior test period, representing an increase of approximately 9%.

Witness Grant stated that DEC's coal burn for the test period was 9.7 million tons, compared to a coal burn of 9.8 million tons in the prior test period, representing a decrease of approximately 1%. Tr., pp. 36-37. The Company's natural gas burn for the test period was 80.8 MMBtu, compared to a gas burn of 89.0 MMBtu in the prior test period, representing a decrease of approximately 9%. The primary contributing factors were changes in (1) weather driven demand, and (2) commodity prices.

Witness Grant stated that DEC's current coal burn projection for the billing period is 8.1 million tons, compared to 9.7 million tons consumed during the test period. Tr., p. 38. DEC's billing period projections for coal generation may be impacted due to changes from, but not limited to, the following factors: (1) delivered natural gas prices versus the average delivered cost of coal; (2) volatile power prices; and (3) electric demand. Combining coal and transportation costs, DEC projects average delivered coal costs of approximately $73.12 per ton for the billing period compared to $74.90 per ton in the test period.

Witness Grant testified that this cost, however, is subject to change based on, but not limited to, the following factors: (1) exposure to market prices and their impact on open coal positions; (2) the amount of non-Central Appalachian coal DEC is able to consume; (3) performance of contract deliveries by suppliers and railroads which may not occur despite DEC's strong contract compliance monitoring process; (4) changes in transportation rates; and (5) potential additional costs associated with suppliers' compliance with legal and statutory changes, the effects of which can be passed on through coal contracts.

Witness Grant further testified that DEC's current natural gas burn projection for the billing period is approximately 138.1 MMBtu, which is an increase from the 80.8 MMBtu consumed during the test period. Tr., p. 39. The net increase in DEC's overall natural gas burn projections for the billing period versus the test period is driven by (1) the new Lee combined cycle facility, which is scheduled to become commercially available in early 2018, and (2) the inclusion of natural gas generation at Cliffside as a result of the dual fuel conversion becoming commercial available in late 2018. The current average forward Henry Hub price for the billing period is $2.98 per MMBtu, compared to $3.11 per MMBtu in the test period. Projected natural gas burn volumes will vary based on factors such as, but not limited to, changes in actual delivered fuel costs and weather driven demand.

ELECTRIC – MISCELLANEOUS

According to witness Grant, DEC continues to maintain a comprehensive coal and natural gas procurement strategy that has proven successful over the years in limiting average annual fuel price changes while actively managing the dynamic demands of its fossil fuel generation fleet in a reliable and cost effective manner. Tr., pp. 39-40. Aspects of this procurement strategy include having an appropriate mix of contract and spot purchases for coal, staggering coal contract expirations which thereby limit exposure to market price changes, diversifying coal sourcing as economics warrant, as well as working with coal suppliers to incorporate additional flexibility into their supply contracts. The Company expects to address any spot and long-term coal requirements throughout this year with any potential competitively bid purchases, if made, taking into account projected coal burns, as well as coal inventory levels.

Witness Grant also testified that the Company has implemented natural gas procurement practices that include periodic Request for Proposals and shorter-term market engagement activities to procure and actively manage a reliable, flexible, diverse, and competitively priced natural gas supply that includes contracting for volumetric optionality in order to provide flexibility in responding to changes in forecasts.

According to witness Grant, DEC continues to maintain a short-term financial natural gas hedging plan to manage fuel cost risk for customers via a disciplined, structured execution approach. Tr., p. 40.

Section 62-133.2(a1)(3) of the North Carolina General Statutes permits DEC to recover the cost of "ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions." Company witness Miller testified that the Company has installed pollution control equipment in order to meet various current federal, state, and local reduction requirements for nitrogen oxide (NO_X) and sulphur oxide (SO_X) emissions. The selective non-catalytic reduction technology (SCR) that DEC currently operates on the coal-fired units uses ammonia or urea for NO_x removal. Tr., p. 45. The SNCR technology employed at Allen station and Marshall Units 1, 2 and 4 injects urea into the boiler for NO_x removal. All DEC coal units have wet scrubbers installed which use crushed limestone for sulfur dioxide (SO_2) removal. Cliffside Unit 6 has a state-of-the-art SO_2 reduction system which couples a wet scrubber (e.g., limestone) and dry scrubber (e.g., quicklime). SCR equipment is also an integral part of the design of the Buck and Dan River CC's, in which aqueous ammonia (19% solution of NH_3) is introduced for NO_x removal.

Company witness Miller further testified that overall, the type and quantity of chemicals used to reduce emissions at the Company's plants varies depending on the generation output of the unit, the chemical constituents in the fuel burned, and the level of emissions reduction required. Tr., p. 52. He stated that the Company is managing the impacts, favorable or unfavorable, as a result of changes to the fuel mix and/or changes in coal burn due to competing fuels and utilization of non-traditional coals. He also stated that the goal is to effectively comply with emissions regulations and provide the most efficient total-cost solution for operation of the unit.

Company witness Houston testified as to DEC's nuclear fuel procurement practices, which include computing near and long-term consumption forecasts, establishing nuclear system inventory levels, projecting required annual fuel purchases, requesting proposals from qualified suppliers, negotiating a portfolio of long-term contracts from diverse sources of supply, and monitoring deliveries against contract commitments. Tr., pp. 73-74. Witness Houston explained that for uranium concentrates as well as conversion and enrichment services, long-term contracts are used extensively in the industry to cover forward requirements and ensure security of supply. He also stated that throughout the industry, the initial delivery under new long-term contracts commonly occurs several years after contract execution. For this reason, DEC relies extensively on long-term contracts to cover the largest portion of its forward requirements. By staggering long-term contracts over time for these components of the nuclear fuel cycle, DEC's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out the Company's exposure to price volatility. He further stated that diversifying fuel suppliers reduces the Company's exposure to possible disruptions from any single source of supply. Due to the technical complexities of changing fabrication services suppliers, DEC generally sources these services to a single domestic supplier on a plant-by-plant basis, using multi-year contracts.

Pursuant to N.C.G.S. §§ 62-133.2(a1)(4), (5), (6), and (7), DEC can recover the cost of non-capacity power purchases subject to economic dispatch or economic curtailment; capacity costs of power purchases associated with qualifying facilities subject to economic dispatch; certain costs associated with power purchases from renewable energy facilities; and the fuel costs of other power purchases. Company witness Grant testified that DEC considers the latest forecasted fuel prices, transportation rates, planned maintenance and refueling outages at generating units, generating unit performance parameters, and expected market conditions, in order to determine the most economic and reliable means of serving their customers. Tr., p. 36.

No party presented or elicited testimony contesting the Company's fuel and reagent procurement and power purchasing practices. Based upon the fuel procurement practices report, the evidence in the record, and the absence of any direct testimony to the contrary, the Commission concludes that these practices were reasonable and prudent during the test period.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness McGee.

According to the exhibits sponsored by Company witness McGee, the test period per book system sales were 85,087,285 MWh, and test period per book system generation and purchased power amounted to 91,830,315 MWh (net of auxiliary use and joint owner generation). The test period per book system generation and purchased power are categorized as follows (McGee Exhibit 6):

Net Generation Type	MWh
Coal	25,573,401
Natural Gas, Oil and Biomass	10,964,809
Nuclear	44,387,125
Hydro – Conventional	1,517,922
Hydro Pumped Storage	(868,059)

Solar DG	125,812
Purchased Power – subject to economic dispatch or curtailment	7,355,868
Other Purchased Power	2,100,330
Catawba Interchange	673,107
Total Net Generation	91,830,315

The evidence presented regarding the operation and performance of the Company's baseload generation facilities is discussed in the Evidence and Conclusions for Finding of Fact Nos. 4-6.

No party took issue with the portions of witness McGee's exhibits setting forth per books system sales, generation by fuel type, and purchased power. Therefore, based on the evidence presented and noting the absence of evidence presented to the contrary, the Commission concludes that the per books levels of test period system sales of 85,087,285 MWh and system generation and purchased power of 91,830,315 MWh are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence supporting this finding of fact is contained in the direct testimony and exhibits of Company witness Batson.

Commission Rule R8-55(d)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent NERC Generating Availability Report, adjusted to reflect the unique, inherent characteristics of the utility's facilities and any unusual events. The Company proposed using a 93.31% capacity factor in this proceeding based on the operational history of the Company's nuclear units and the number of planned outage days scheduled during the billing period. Tr., p. 67. This proposed capacity factor exceeds the five-year industry weighted average capacity factor of 88.76% for the period 2011-2015 as reported in the NERC Brochure during the period of 2012 to 2016.

Based upon the requirements of Commission Rule R8-55(d)(1), the historical and reasonably expected performance of the DEC system, and the fact that the Public Staff did not dispute the Company's proposed capacity factor, the Commission concludes that the 93.31% nuclear capacity factor, and its associated generation of 58,688,771 MWh, are reasonable and appropriate for determining the appropriate fuel and fuel-related costs in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10-12

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness McGee.

On her Exhibit 4, Company witness McGee set forth the test year per books North Carolina retail sales, adjusted for weather and customer growth, of 56,823,684 MWh, comprised of Residential class sales of 21,099,293 MWh, General Service/Lighting class sales of 23,106,793 MWh, and Industrial class sales of 12,617,598 MWh.

Witness McGee used projected billing period system sales, generation, and purchased power to calculate the proposed prospective component of the fuel and fuel-related cost rate. The projected system sales level used, as set forth on Revised McGee Exhibit 2, Schedule 1, is 86,966,251 MWh. The projected level of generation and purchased power used was 92,085,162 MWh (calculated using the 93.31% capacity factor found reasonable and appropriate above), and was broken down by witness McGee as follows, as set forth on that same schedule:

Generation Type	MWh
Coal	24,506,235
Gas Combustion Turbine (CT) and Combined Cycle (CC)	15,192,940
Nuclear	43,840,571
Hydro	4,927,068
Net Pumped Storage Hydro	(3,999,271)
Solar Distributed Generation (DG)	162,037
Purchased Power	7,455,582
Total	92,085,162

As part of her Workpaper 7, Company witness McGee also presented an estimate of the projected billing period North Carolina retail Residential, General Service/Lighting, and Industrial MWh sales. The Company estimates billing period North Carolina retail MWh sales to be as follows:

N.C. Retail Customer Class	Projected MWh Sales
Residential	21,325,336
General Service/Lighting	23,055,058
Industrial	12,649,951
Total	57,030,345

These class totals were used in McGee Exhibit 2, Schedule 1, in calculating the total fuel and fuel-related cost factors by customer class.

Based on the evidence presented by the Company, the Public Staff's acceptance of the amounts presented by the Company, and the absence of evidence presented to the contrary, the Commission concludes that the projected North Carolina retail levels of sales set forth in the Company's exhibits (normalized for customer growth and weather), as well as the projected levels of generation and purchased power, are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 13

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witnesses McGee and Grant and the affidavit of Public Staff witness Metz.

Company witness McGee recommended fuel and fuel-related prices and expenses, for purposes of determining projected system fuel expense, as follows:

A. The coal fuel price is $24.75/MWh.
B. The gas CT and CC fuel price is $25.32/MWh.
C. The appropriate expense for ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions (collectively, Reagents) is $34,275,781.
D. The total nuclear fuel price (including Catawba Joint Owners generation) is $6.53/MWh.
E. The total system purchased power cost (including the impact of Joint Dispatch Agreement (JDA) Savings Shared) is $35.61/MWh.
F. System fuel expense recovered through intersystem sales is $35,970,078.

These amounts are set forth on or derived from Revised McGee Exhibit 2, Schedule 1. The total adjusted system fuel and fuel-related expense, based in part on the use of these amounts, is utilized to calculate the prospective fuel and fuel-related cost factors recommended by the Company and the Public Staff.

In his testimony, Public Staff witness Metz stated that, based upon the investigation of Public Staff, the projected fuel and reagent costs set forth in the Company's testimony are reasonable and were calculated appropriately.

No other party presented evidence on the level of DEC's fuel and fuel-related prices and expenses.

Based upon the evidence in the record as to the appropriate fuel and fuel-related prices and expenses, the Commission concludes that the fuel and fuel-related prices recommended by Company witness McGee and accepted by the Public Staff for purposes of determining projected system fuel expense are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness McGee and the affidavit of Public Staff witness Metz.

Consistent with N.C.G.S. § 62-133.2(a2), McGee Workpaper 10 shows that the annual increase in the aggregate amount of fuel-related expenses associated with non-capacity purchased power costs, qualifying facility capacity costs, and renewable energy costs does not exceed two and one half percent of DEC's total North Carolina jurisdictional gross revenues for 2017.

According to McGee Exhibit 2, Schedule 1, the projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $1,013,394,952. Public Staff witness Metz did not take issue with her calculation.

Aside from the Company and the Public Staff, no other party presented or elicited testimony contesting the Company's projected fuel and fuel-related costs for the North Carolina retail jurisdiction. Based upon the evidence in the record and the absence of any direct testimony to the contrary, the Commission concludes that the Company's projected total fuel and fuel-related cost for the North Carolina retail jurisdiction of $1,013,394,952 is reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15-19

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness McGee and the affidavits of Public Staff witnesses Metz and Peedin.

Company witness McGee presented DEC's original fuel and fuel-related expense under-collection and prospective fuel and fuel-related cost factors. Company witness McGee's supplemental testimony and revised exhibits set forth the final and revised projected fuel and fuel-related costs, the amount of under-collection for purposes of the EMF, the method for allocating the increase in fuel and fuel-related costs, the composite fuel and fuel-related cost factors, and the EMFs along with exhibits and workpapers to correct an error in the wholesale weather normalization adjustment and updating the EMF to incorporate the fuel and fuel related cost recovery balance for January through March 2018, pursuant to Commission Rule R8-55(d)(3).

DEC witness McGee Revised Exhibit 3 shows that the EMF riders proposed by DEC are based on DEC's calculated and reported North Carolina retail fuel and fuel-related cost under-recoveries of $20.7 million, $24.7 million, and $27.9 million for the Residential, General Service/Lighting, and Industrial classes, respectively. She recommended that DEC's EMF riders for each customer class be based on these net fuel and fuel-related cost under-recovery amounts and on the Company's proposed normalized North Carolina retail sales of 21,099,293 MWh for the residential class, 23,106,793 MWh for the general service/lighting class, and 12,617,598 MWh for the industrial class, as proposed by the Company. These amounts produce EMF increment riders for each North Carolina retail customer class as follows, excluding the regulatory fee:

Residential	0.0980 cents per kWh
General Service/Lighting	0.1068 cents per kWh
Industrial	0.2213 cents per kWh

Company witness McGee calculated the Company's proposed fuel and fuel-related cost factors using a uniform bill adjustment method. She stated that the increase in fuel costs from the amounts approved in Docket No. E-7, Sub 1129, should be allocated between the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology utilized in past DEC fuel cases approved by this Commission. No party opposed the use of this allocation method.

Public Staff witnesses Peedin and Metz presented the under-collection amounts, EMF increments, and prospective fuel and fuel-related cost factors recommended by the Public Staff, which included the $433,911 adjustment to replacement power costs recommended by witness Metz. However, as discussed above in the Evidence and Conclusions for Finding of Fact Nos. 4-6, the Commission finds that DEC's baseload plants were managed prudently and efficiently during the test period.

Based upon the testimony and exhibits in the record, the Commission concludes that DEC's projected fuel and fuel-related cost of $1,013,394,952 for the North Carolina retail jurisdiction for use in this proceeding is reasonable. The Commission also concludes that (1) DEC's EMFs proposed in this proceeding, excluding the regulatory fee and (2) DEC's prospective fuel and fuel-related cost factors proposed in this proceeding for each of DEC's rate classes are appropriate. Additionally, the Commission concludes that DEC's increase in fuel and fuel-related costs from the amounts approved in Docket No. E-7, Sub 1129 should be allocated between the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology approved by this Commission in DEC's past fuel cases.

The following tables summarize the impact of the rates approved in this case and the rates approved in Docket No. E-7 Sub 1129 (excluding regulatory fee).

Approved in Docket No. E-7, Sub 1129 (excluding regulatory fee):

Description	Residential cents/kWh	General cents/kWh	Industrial cents/kWh
Base Fuel	2.3182	2.3182	2.3182
Prospective Component	(0.5354)	(0.4019)	(0.2975)
EMF Component	(0.1081)	(0.0764)	(0.0711)
Total Fuel Factor	1.6747	1.8399	1.9496

Approved in this Docket No. E-7, Sub 1163 (excluding regulatory fee):

Description	Residential cents/kWh	General cents/kWh	Industrial cents/kWh
Base Fuel	1.7828	1.9163	2.0207
Prospective Component	(0.0825)	(0.0849)	(0.2187)
EMF Component	0.0980	0.1068	0.2213
Total Fuel Factor	1.7983	1.9382	2.0233

Summary of Differences Sub 1163 — 1129 (excluding regulatory fee):

Description	Residential cents/kWh	General cents/kWh	Industrial cents/kWh
Base Fuel	(0.5354)	(0.4019)	(0.2975)
Prospective Component	0.4529	0.3170	0.0788
EMF Component	0.2061	0.1832	0.2924
Total Fuel Factor	0.1236	0.0983	0.0737

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 20

The evidence for this finding of fact is contained in the testimony of Company witness McGee and in the affidavits of Public Staff witnesses Peedin and Metz and is discussed in more detail in Evidence and Conclusions for Finding of Fact No. 5.

The Commission has carefully reviewed the evidence and record in this proceeding. The test period and projected fuel and fuel-related costs, and the proposed factors, including the EMF, are not opposed by any party except for the Public Staff's proposed adjustment to DEC's replacement power costs for the Oconee outage discussed above. Accordingly, the overall fuel and fuel-related cost calculation, incorporating the conclusions reached herein, results in net fuel and fuel-related cost factors of 1.7983¢/kWh for the Residential class, 1.9382¢/kWh for the General Service/Lighting class, and 2.0233¢/kWh for the Industrial class, excluding regulatory fee, consisting of the prospective fuel and fuel-related cost factors of 1.7003¢/kWh, 1.8314¢/kWh, and 1.8020¢/kWh, EMF increments of 0.0980¢kWh, 0.1068¢kWh, and 0.2213¢/kWh, all respectively, excluding the regulatory fee.

IT IS, THEREFORE, ORDERED:

1. That, effective for service rendered on and after September 1, 2018, DEC shall adjust the base fuel and fuel-related costs in its North Carolina retail rates of 1.7828¢/kWh, 1.9163¢/kWh, and 2.0207¢/kWh for the Residential, General Service/Lighting, and Industrial classes, respectively as approved in Docket No. E-7, Sub 1146, by amounts equal to (0.0825)¢/kWh, (0.0849)¢/kWh, and (0.2187)¢/kWh for the Residential, General Service/Lighting, and Industrial classes, respectively, and further, that DEC shall adjust the resulting approved fuel and fuel-related costs by EMF increments of 0.0980¢/kWh for the Residential class, 0.1068¢/kWh for the General Service/Lighting class, and 0.2213¢/kWh for the Industrial class (excluding the regulatory fee). The EMF increments are to remain in effect for service rendered through August 31, 2019.

2. That DEC shall file appropriate rate schedules and riders with the Commission in order to implement these approved rate adjustments as soon as practicable.

3. That DEC shall work with the Public Staff to prepare a notice to customers of the rate changes ordered by the Commission in this docket, as well as in Docket No. E-7, Sub 1162, and the Company shall file such notice for Commission approval as soon as practicable, but not later than ten (10) days after the Commission issues orders in both dockets.

ISSUED BY ORDER OF THE COMMISSION.
This the 20th day of August, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. E-7, SUB 1164

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Carolinas, LLC, for Approval of Demand-Side Management and Energy Efficiency Cost Recovery Rider Pursuant to N.C. Gen. Stat. § 62-133.9 and Commission Rule R8-69	)))))	ORDER APPROVING DSM/EE RIDER AND REQUIRING FILING OF CUSTOMER NOTICE

HEARD: On Tuesday, June 5, 2018, in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

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

APPEARANCES:

For Duke Energy Carolinas, LLC:

Kendrick C. Fentress, Duke Energy Carolinas, LLC, P.O. Box 1551, Raleigh, North Carolina 27602

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For the North Carolina Sustainable Energy Association:

Benjamin Smith and Peter H. Ledford, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For the Carolina Utility Customers Association, Inc.:

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

For the North Carolina Justice Center, Natural Resources Defense Council, and the Southern Alliance for Clean Energy:

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

For The Carolina Industrial Group for Fair Utility Rates III:

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

For the Using and Consuming Public:

Lucy E. Edmondson, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699

BY THE COMMISSION: Pursuant to N.C. Gen. Stat. § 62-133.9(d) the North Carolina Utilities Commission (Commission) is authorized to approve an annual rider to the rates of electric public utilities, outside of a general rate case, for recovery of all reasonable and prudent costs incurred for adoption and implementation of new demand-side management (DSM) and energy efficiency (EE) measures. The Commission is also authorized to award incentives to electric companies for adopting and implementing new DSM/EE measures, including, but not limited to, appropriate rewards based on (1) the sharing of savings achieved by the DSM and EE measures and/or (2) the capitalization of a percentage of avoided costs achieved by the measures. Commission Rule R8-69(b) provides that every year the Commission will conduct a proceeding for each electric public utility to establish an annual DSM/EE rider to recover the reasonable and prudent costs incurred by the electric utility in adopting and implementing new DSM/EE measures previously approved by the Commission pursuant to Commission Rule R8-68. Further, Commission Rule R8-69(b) provides for the establishment of a DSM/EE experience modification factor (EMF) rider to allow the electric public utility to collect the difference between reasonable and prudently incurred costs and the revenues that were actually realized during the test period under the DSM/EE rider then in effect. Commission Rule R8-69(c) permits the utility to request the inclusion of utility incentives (the rewards authorized by the statute), including net lost revenues (NLR), in the DSM/EE rider and the DSM/EE EMF rider.

In the present proceeding, Docket No. E-7, Sub 1164, on March 7, 2018, Duke Energy Carolinas, LLC (DEC or the Company), filed an application for approval of its DSM/EE rider (Rider EE[1] or Rider 10) for 2019[2] (Application) and the direct testimony and exhibits of Carolyn T. Miller, Manager, Rates and Regulatory Strategy for DEC, and Robert P. Evans, Senior Manager – Strategy and Collaboration for the Carolinas in the Company's Market Solutions Regulatory Strategy and Evaluation group.

On March 29, 2018, the Commission issued an Order scheduling a hearing for June 5, 2018, establishing discovery guidelines, providing for intervention and testimony by other parties, and requiring public notice.

The intervention of the Public Staff – North Carolina Utilities Commission (Public Staff) is recognized pursuant to N.C. Gen. Stat. § 62-15(d) and Commission Rule R1-19(e). On March 16, 2018, the North Carolina Sustainable Energy Association (NCSEA) filed a petition to intervene, which was granted on March 23, 2018. On April 10, 2018, the Carolina Utility

[1] DEC refers to its DSM/EE Rider as "Rider EE"; however, this rider includes charges intended to recover both DSM and EE revenue requirements.

[2] The Rider EE proposed in this proceeding is the Company's tenth Rider EE and includes components that relate to Vintages 2014, 2015, 2016, 2017, 2018, and 2019 of the Revised Mechanism. For purposes of clarity, the aggregate rider is referred to in this Order as "Rider 10" or the proposed "Rider EE." Rider 10 is proposed to be effective for the rate period January 1, 2019, through December 31, 2019.

Customers Association, Inc. (CUCA) filed a petition to intervene, which was granted on April 11, 2018. On May 1, 2018, the North Carolina Justice Center (NC Justice Center) and the Southern Alliance for Clean Energy (SACE), filed a petition to intervene, and on May 21, 2018, Natural Resources Defense Council (NRDC, collectively, NC Justice Center) filed a petition to intervene. These petitions were granted on May 2 and 30, 2018, respectively. The Carolina Industrial Group for Fair Utility Rates III (CIGFUR) filed a petition to intervene on May 17, 2018, which was granted on May 18, 2018.

On May 21, 2018, the Public Staff and NC Justice Center filed a motion for an extension of time in which to file intervenor testimony to May 22, 2018, and to file rebuttal testimony to June 1, 2018. The motion was granted by the Commission on May 21, 2018.

On May 22, 2018, NC Justice Center filed the testimony of Chris Neme, co-founder and Principal of Energy Futures Group; and the Public Staff filed the testimony and exhibits of Michael C. Maness, Director of the Accounting Division; David M. Williamson, Engineer in the Electric Division; and Eric L. Williams, Financial Analyst in the Economic Research Division.

On June 1, 2018, DEC filed the joint rebuttal testimony of Timothy J. Duff, General Manager of Customer Regulatory Strategy and Evaluation at Duke Energy Business Services LLC, and Richard G. Stevie, Ph.D., Vice President of Forecasting at Integral Analytics, Inc.; and the rebuttal testimony and exhibits of witnesses Miller and Evans.

On June 1, 2017, DEC filed a motion to excuse witness Miller and NC Justice Center filed a motion to excuse witness Neme from appearing at the June 5, 2018, expert witness hearing. On June 4, 2017, the Commission issued an order granting both motions.

The case came on for hearing as scheduled on June 5, 2018. No public witnesses appeared at the hearing.

On July 13, 2018, DEC filed a late-filed exhibit containing information relating to the My Home Energy Report Program that was requested by Presiding Commissioner Brown-Bland during the expert witness hearing.

On July 19, 2018, the Public Staff filed a letter indicating that it had completed its review of DEC's 2017 DSM/EE program costs and had found no exceptions.

On July 20, 2018, the parties filed briefs or proposed orders, as allowed by the Commission.

<u>Other Pertinent Proceedings:</u>
<u>Docket Nos. E-7, Subs 831, 938, 979, 1032, and 1130, and E-100, Sub 148</u>

On February 9, 2010, the Commission issued an Order Approving Agreement and Joint Stipulation of Settlement Subject to Certain Commission-Required Modifications and Decisions on Contested Issues in DEC's first DSM/EE rider proceeding, Docket No. E-7, Sub 831 (Sub 831 Order). In the Sub 831 Order, the Commission approved, with certain modifications, the

Agreement and Joint Stipulation of Settlement (Sub 831 Settlement) between DEC, the Public Staff, SACE, the Environmental Defense Fund (EDF), National Resources Defense Council (NRDC), and the Southern Environmental Law Center (SELC), which described the modified save-a-watt mechanism (Sub 831 Mechanism), pursuant to which DEC calculated, for the period from June 1, 2009 until December 31, 2013, the revenue requirements underlying its DSM/EE riders based on percentages of avoided costs, plus compensation for NLR resulting from EE programs only. The Sub 831 Mechanism was approved as a pilot (Sub 831 Pilot) with a term of four years, ending on December 31, 2013.

On February 15, 2010, the Company filed an Application for Waiver of Commission Rule R8-69(a)(4) and R8-69(a)(5) in Docket No. E-7, Sub 938 (Sub 938 Waiver Application), requesting waiver of the definitions of "rate period" and "test period." Under the Sub 831 Mechanism, customer participation in the Company's DSM and EE programs and corresponding responsibility to pay Rider EE are determined on a vintage year basis. A vintage year is generally the 12-month period in which a specific DSM or EE measure is installed for an individual participant or group of participants.[1] For purposes of the modified save-a-watt portfolio of programs, the Company applied the vintage year concept on a calendar-year basis for administrative ease for the Company and its customers. Pursuant to the Sub 938 Waiver Application, "test period" is defined as the most recently completed vintage year at the time of the Company's DSM/EE rider application filing date.[2]

On February 24, 2010, in Docket No. E-7, Sub 938, the Commission issued an Order Requesting Comments on the Company's Sub 938 Waiver Application. After receiving comments and reply comments, the Commission entered an Order Granting Waiver, in Part, and Denying Waiver, in Part (Sub 938 Waiver Order) on April 6, 2010. In this Order, the Commission approved the requested waiver of R8-69(d)(3) in part, but denied the Company's requested waiver of the definitions of "rate period" and "test period."

On May 6, 2010, DEC filed a Motion for Clarification or, in the Alternative, for Reconsideration, asking that the Commission reconsider its denial of the waiver of the definitions of "test period" and "rate period," and that the Commission clarify that the EMF may incorporate adjustments for multiple test periods. In response, the Commission issued an Order on Motions for Reconsideration on June 3, 2010 (Sub 938 Second Waiver Order), granting DEC's Motion. The Sub 938 Second Waiver Order established that the rate period for Rider EE would align with the 12-month calendar year vintage concept utilized in the Commission-approved save-a-watt approach (in effect, the calendar year following the Commission's order in each annual DSM/EE cost recovery proceeding), and that the test period for Rider EE would be the most

[1] Vintage 1 is an exception in terms of length. Vintage 1 is a 19-month period beginning June 1, 2009, and ending December 31, 2010, as a result of the approval of DSM/EE programs prior to the approval of the Sub 831 Mechanism.

[2] In the Sub 938 Second Waiver Order issued June 3, 2010, the Commission concluded that DEC should true up all costs during the save-a-watt pilot through the EMF rider provided in Commission Rule R8-69(b)(1). The modified save-a-watt approach approved in the Sub 831 Order required a final calculation after the completion of the four-year program, comparing the cumulative revenues collected related to all four vintage years to amounts due the Company, taking into consideration the applicable earnings cap.

recently completed vintage year at the time of the Company's Rider EE cost recovery application filing date.

On February 8, 2011, in Docket No. E-7, Sub 831, the Commission issued its Order Adopting "Decision Tree" to Determine "Found Revenues" and Requiring Reporting in DSM/EE Cost Recovery Filings in Docket No. E-7, Sub 831 (Sub 831 Found Revenues Order), which included, in Appendix A, a "Decision Tree" to identify, categorize, and net possible found revenues against the NLR created by the Company's EE programs. Found revenues may result from activities that directly or indirectly result in an increase in customer demand or energy consumption within the Company's service territory.

On November 8, 2011, in Docket No. E-7, Sub 979, the Commission issued its Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice (Sub 979 Order), in which it approved the Evaluation, Measurement, and Verification (EM&V) agreement (EM&V Agreement) reached by the Company, SACE, and the Public Staff. Pursuant to the EM&V Agreement, for all EE programs, with the exception of the Non-Residential Smart $aver Custom Rebate program and the Low-Income EE and Weatherization Assistance program, actual EM&V results are applied to replace all initial impact estimates back to the beginning of the program offering. For the purposes of the vintage true-ups, these initial EM&V results are considered actual results for a program until the next EM&V results are received. The new EM&V results are then considered actual results going forward and will be applied prospectively for the purposes of truing up vintages from the first day of the month immediately following the month in which the study participation sample for the EM&V was completed. These EM&V results will then continue to apply and be considered actual results until superseded by new EM&V results, if any. For all new programs and pilots, the Company will follow a consistent methodology, meaning that initial estimates of impacts will be used until DEC has valid EM&V results, which will then be applied back to the beginning of the offering and will be considered actual results until a second EM&V is performed.

On February 6, 2012, in the Sub 831 docket, the Company, SACE, and the Public Staff filed a proposal regarding revisions to the program flexibility requirements (Flexibility Guidelines). The proposal divided potential program changes into three categories based on the magnitude of the change, with the most significant changes requiring regulatory approval by the Commission prior to implementation; less extensive changes requiring advance notice prior to making such program changes; and minor changes being reported on a quarterly basis to the Commission. The Commission approved the joint proposal in its July 16, 2012 Order Adopting Program Flexibility Guidelines.

On October 29, 2013, the Commission issued its Order Approving DSM/EE Programs and Stipulation of Settlement in Docket No. E-7, Sub 1032 (Sub 1032 Order), which approved a new cost recovery and incentive mechanism for DSM/EE programs (Sub 1032 Mechanism) and a portfolio of DSM and EE programs to be effective January 1, 2014, to replace the cost recovery mechanism and portfolio of DSM and EE programs approved in Docket No. E-7, Sub 831. In the Sub 1032 Order, the Commission approved an Agreement and Stipulation of Settlement, filed on August 19, 2013, and amended on September 23, 2013, by and between DEC, NCSEA, EDF, SACE, the South Carolina Coastal Conservation League, NRDC, the Sierra Club, and the Public Staff, which incorporates the Sub 1032 Mechanism (Sub 1032 Stipulation).

Under the Sub 1032 Stipulation, as approved by the Commission, the portfolio of DSM and EE programs filed by the Company was approved with no specific duration (unlike the programs approved in Sub 831, which explicitly expired on December 31, 2013). Additionally, the Sub 1032 Stipulation also provided that the Company's annual DSM/EE rider would be determined according to the Sub 1032 Stipulation and the terms and conditions set forth in the Sub 1032 Mechanism, until otherwise ordered by the Commission. Under the Sub 1032 Stipulation, the Sub 1032 Mechanism was to be reviewed in four years. Pursuant to the Sub 1032 Stipulation, any proposals for revisions to the Sub 1032 Mechanism were to be filed by parties along with their testimony in the annual DSM/EE rider proceeding.

The overall purpose of the Sub 1032 Mechanism is to (1) allow DEC to recover all reasonable and prudent costs incurred for adopting and implementing new DSM and EE measures; (2) establish certain requirements, in addition to those of Commission Rule R8-68, for requests by DEC for approval, monitoring, and management of DSM and EE programs; (3) establish the terms and conditions for the recovery of NLR (net of found revenues) and a Portfolio Performance Incentive (PPI) to reward DEC for adopting and implementing new DSM and EE measures and programs; and (4) provide for an additional incentive to further encourage kilowatt-hour (kWh) savings achievements. The Sub 1032 Mechanism includes the following provisions, among several others: (a) the mechanism shall continue until terminated pursuant to Commission Order; (b) modifications to Commission-approved DSM/EE programs will be made using the Flexibility Guidelines; (c) treatment of opted-out and opted-in customers will continue to be guided by the Commission's Orders in Docket No. E-7, Sub 938, with the addition of an additional opt-in period during the first week in March of each year; (d) the EM&V Agreement shall continue to govern the application of EM&V results; and (e) the determination of found revenues will be made using the Decision Tree approved in the Sub 831 Found Revenues Order. Like the Sub 831 Mechanism, the Sub 1032 Mechanism also employs a vintage year concept based on the calendar year.[1]

On August 23, 2017, in Docket No. E-7, Sub 1130 (Sub 1130), the Commission approved certain revisions to the Sub 1032 Mechanism effective January 1, 2018 (Revised Mechanism). The Sub 1032 Mechanism was revised to (1) set out how the avoided costs are determined for purposes of calculating the PPI, (2) specify the avoided costs to be used for purposes of program approval, and (3) specify the avoided costs to be used in calculating ongoing cost-effectiveness, as well as setting out a procedure for modification or closure of programs that are no longer cost-effective.

Specifically in Sub 1130, paragraph 69 of the Sub 1032 Mechanism, which describes how avoided costs are determined for purposes of calculating the PPI, was revised such that for Vintage 2019 and beyond, the program-specific avoided capacity benefits and avoided energy benefits will be derived from the underlying resource plan, production cost model, and cost inputs that generated the avoided capacity and avoided energy credits reflected in the most recent

[1] Each vintage under the Sub 1032 Mechanism and the Revised Mechanism is referred to by the calendar year of its respective rate period (e.g., Vintage 2018).

Commission-approved Biennial Determination of Avoided Cost Rates as of December 31 of the year immediately preceding the annual DSM/EE rider filing date. For the calculation of the underlying avoided energy credits to be used to derive the program-specific avoided energy benefits, the calculation will be based on the projected EE portfolio hourly shape, rather than the assumed 24x7 100-megawatt (MW) reduction typically used to represent a qualifying facility (QF).

Additionally, Paragraph 19 of the Sub 1032 Mechanism was revised to specify that the avoided costs used for purposes of program approval filings would also be determined using the method outlined in revised Paragraph 69. The specific Biennial Determination of Avoided Cost Rates used for each program approval filing would be derived from the rates most recently approved by the Commission as of the date of the program approval filing. Paragraph 23 of the Sub 1032 Mechanism was revised, and Paragraphs 23A-D were added, to specify which avoided costs should be used for determining the continuing cost-effectiveness of programs and actions to be taken based on the results of those tests. Pursuant to Paragraph 23, each year the Company files an analysis of the current cost-effectiveness of each of its DSM/EE programs as part of the DSM/EE rider filing. New Paragraph 23A requires the use of the same method for calculating the avoided costs outlined in the revisions to Paragraph 69 to determine the continued cost-effectiveness for each program. Like revised Paragraph 69, Paragraph 23A specifies that the avoided capacity and energy costs used to calculate cost-effectiveness will be derived from the avoided costs underlying the most recent Commission-approved Biennial Determination of Avoided Cost Rates as of December 31 of the year immediately preceding the annual DSM/EE rider filing date. New Paragraphs 23B through 23D address the steps that will be taken if specific DSM/EE programs continue to produce Total Resource Cost (TRC) test results less than 1.00 for an extended period. For any program that initially demonstrates a TRC of less than 1.00, the Company shall include in its annual DSM/EE rider filing a discussion of the actions being taken to maintain or improve cost-effectiveness, or alternatively, its plans to terminate the program. If a program demonstrates a prospective TRC of less than 1.00 in a second DSM/EE rider proceeding, the Company shall include a discussion of what actions it has taken to improve cost-effectiveness. If a program demonstrates a prospective TRC of less than 1.00 in a third DSM/EE rider proceeding, the Company shall terminate the program effective at the end of the year following the DSM/EE rider order, unless otherwise ordered by the Commission.

The Sub 1032 Mechanism, as revised by the Sub 1130 Order, is set forth in Public Staff witness Maness Exhibit II and referred to herein as the "Mechanism."

<u>Docket No. E-7, Sub 1164</u>

Based upon consideration of DEC's Application, the pleadings, the testimony and exhibits received into evidence at the hearing, the parties' briefs and the record as a whole, the Commission now makes the following

FINDINGS OF FACT

1. DEC is a public utility with a public service obligation to provide electric utility service to customers in its service area in North Carolina and is subject to the jurisdiction of the Commission.

2. The Commission has jurisdiction over this Application pursuant to the Public Utilities Act. A utility may petition the Commission for approval of an annual rider to recover all reasonable and prudent costs incurred for the adoption and implementation of new DSM and EE measures pursuant to N.C. Gen Stat. § 62-133.9 and Commission Rules R8-68 and R8-69. The Commission finds that it has the authority to consider and approve the relief the Company is seeking in this docket.

3. For purposes of this proceeding, DEC has requested approval of costs and incentives related to the following DSM/EE programs to be included in Rider 10: Energy Assessments program; EE Education program; Energy Efficient Appliances and Devices; Residential Smart $aver EE program; Multi-Family EE program; My Home Energy Report (MyHER); Income-Qualified EE and Weatherization program; Power Manager; Non-Residential Smart $aver Energy Efficient Food Service Products program; Non-Residential Smart $aver Energy Efficient HVAC Products program; Non-Residential Smart $aver Energy Efficient IT Products program; Non-Residential Smart $aver Energy Efficient Lighting Products program; Non-Residential Smart $aver Energy Efficient Process Equipment Products program; Non-Residential Smart $aver Energy Efficient Pumps and Drives Products program; Non-Residential Smart $aver Custom program; Non-Residential Smart $aver Custom Energy Assessments program; PowerShare; PowerShare Call Option (canceled effective January 31, 2018); Small Business Energy $aver; Smart Energy in Offices (canceled effective June 30, 2018); EnergyWise for Business; and Non-Residential Smart $aver Performance Incentive.

4. Pursuant to Paragraph 19 of the Mechanism, the Income-Qualified EE and Weatherization program is not required to pass the TRC or UCT tests in order to be eligible for inclusion in the Company's portfolio. No further action by the Company is required with respect to this program.

5. The Non-Residential Smart $aver Custom Energy Assessments and EnergyWise for Business programs are cost-effective under DEC's calculation of avoided capacity costs.

6. The Residential Smart $aver EE program should not be suspended at this time. The Company should propose modifications to this program no later than October 31, 2018, with the goal of restoring the TRC score to 1.0 or greater. The Company should include a discussion of the impact of these modifications and other actions it has taken to improve cost-effectiveness in next year's DSM/EE rider proceeding.

7. Due to both the short amount of time it has been in place and the anticipated increase in cost-effectiveness, the Non-Residential Smart $aver Performance Incentive Program does not require additional scrutiny at this time. If the program does not project cost-effectiveness for Vintage 2020, pursuant to Paragraph 23B of the Mechanism, the Company should provide a

discussion of the actions being taken to maintain or improve cost-effectiveness, or alternatively, its plans to terminate the program in its next DSM/EE rider proceeding.

8. For purposes of inclusion in Rider 10, the Company's portfolio of DSM and EE programs is cost-effective.

9. The EM&V reports filed as Evans Exhibits A, D, E, F, G, H, I, J, K, and L are acceptable for purposes of this proceeding and should be considered complete for purposes of calculating program impacts.

10. The EM&V report for the Non-Residential Smart $aver Custom program (Evans Exhibit B) should be revised as discussed by Public Staff witness Williamson and refiled in the next DSM/EE rider proceeding.

11. The acceptance of the EM&V report for the MyHER program (Evans Exhibit C) should be postponed and addressed in next year's proceeding pending completion of the Public Staff's review.

12. Pursuant to the Commission's Sub 938 Second Waiver Order and the Sub 1032 Order, the rate period for the purposes of this proceeding is January 1, 2019 through December 31, 2019.

13. Rider 10 includes EMF components for Vintage 2017 DSM and EE programs. Consistent with the Sub 938 Second Waiver Order, the test period for these EMF components is the period from January 1, 2017, through December 31, 2017 (Vintage 2017).

14. DEC's proposed rates for Rider 10 are comprised of both prospective and EMF components. The prospective components include factors designed to collect program costs and the PPI for the Company's Vintage 2019 DSM and EE programs, as well as the first year of NLR for the Company's Vintage 2019 EE programs; the second year of NLR for Vintage 2018 EE programs; and the third year of NLR for Vintage 2017 EE programs. The EMF components include true-ups of Vintage 2017 program costs, NLR, and PPI, as well as true-ups for PPI and NLR for Vintages 2014, 2015 and 2016.

15. It is appropriate to reduce the Company's proposed level of 2019 estimated kWh sales for each Non-Residential vintage/factor combination by 3.90%, to hold open the true-up process for Rider 10 until the total actual amount of Rider 10 revenues collected can be reflected in the rate calculation process, and to allow the Company to recover carrying costs on any understatement of Rider 10 billing factors due to the 3.90% reduction. It is also appropriate to limit the portion of the understatement eligible for recovery to the difference between the Public Staff's recommended levels of participating Rider 10 kWh sales and the Company's initially proposed levels of such sales in this proceeding.

16. It is inappropriate to calculate the avoided capacity cost benefits for purposes of the PPI and cost-effectiveness of the Company's DSM/EE programs under the assumption that capacity avoided prior to year 2023 be assigned a zero dollar value. The Public Staff's

recommendation of such, and the corresponding reduction to the Company's Vintage 2019 PPI, is rejected.

17. The components of Rider 10, as reflected in the testimony and exhibits of Company witnesses Miller and Evans, have been calculated in a manner that appropriately reflects the Commission's findings and conclusions in this Order, as well as the Commission's findings and conclusions as set forth in the Sub 831 Order, the Sub 831 Found Revenues Order, the Sub 938 Waiver Order, the Sub 938 Second Waiver Order, the Sub 979 Order, the Sub 1032 Order, and the Commission's Order in Docket No. E-7, Sub 1130 (Sub 1130 Order).

18. The reasonable and prudent Rider 10 billing factor for residential customers[1] is 0.5320 cents per kWh, which, as is the case for all the other billing factors stated in these findings of fact, includes the regulatory fee.

19. The reasonable and prudent Rider 10 Vintage 2019 EE prospective billing factor for non-residential customers who do not opt out of Vintage 2019 of the Company's EE programs is 0.3158 cents per kWh.

20. The reasonable and prudent Rider 10 Vintage 2019 DSM prospective billing factor for non-residential customers who do not opt out of Vintage 2019 of the Company's DSM programs is 0.0877 cents per kWh.

21. The reasonable and prudent Rider 10 Vintage 2018 prospective EE billing factor for non-residential customers who participated in Vintage 2018 of the Company's EE programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2018 during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2019) is 0.0695 cents per kWh.

22. The reasonable and prudent Rider 10 Vintage 2018 DSM prospective billing factor for non-residential customers who participated in Vintage 2018 of the Company's DSM programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2018 during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2019) is 0.0030 cents per kWh.

23. The reasonable and prudent Rider 10 Vintage 2017 prospective EE billing factor for non-residential customers who participated in Vintage 2017 of the Company's EE programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2017 during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2019) is 0.0801 cents per kWh.

24. The reasonable and prudent Rider 10 Vintage 2017 EE EMF billing factor for non-residential customers who participated in Vintage 2017 of the Company's EE programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2017 during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2019) is 0.2924 cents per kWh.

[1] The residential billing factor applicable to all residential customers is the sum of the residential prospective and residential true-up factors for the applicable vintage years.

25. The reasonable and prudent Rider 10 Vintage 2017 DSM EMF billing factor for non-residential customers who participated in Vintage 2017 of the Company's DSM programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2017 during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2019) is 0.0005 cents per kWh.

26. The reasonable and prudent Rider 10 Vintage 2016 EE EMF billing factor for non-residential customers who participated in Vintage 2016 of the Company's EE programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2016 during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2019) is (0.0126) cents per kWh.

27. The reasonable and prudent Rider 10 Vintage 2016 DSM EMF billing factor for non-residential customers who participated in Vintage 2016 of the Company's DSM programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2016 during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2019) is (0.0015) cents per kWh.

28. The reasonable and prudent Rider 10 Vintage 2015 EE EMF billing factor for non-residential customers who participated in Vintage 2015 of the Company's EE programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2015 during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2019) is 0.0024 cents per kWh.

29. The reasonable and prudent Rider 10 Vintage 2015 DSM EMF billing factor for non-residential customers who participated in Vintage 2015 of the Company's DSM programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2015 during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2019) is (0.0024) cents per kWh.

30. The reasonable and prudent Rider 10 Vintage 2014 EE EMF billing factor for non-residential customers who participated in Vintage 2014 of the Company's EE programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2014 during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2019) is (0.0061) cents per kWh.

31. The reasonable and prudent Rider 10 Vintage 2014 DSM EMF billing factor for non-residential customers who participated in Vintage 2014 of the Company's DSM programs (or who did not so participate, but neither (a) explicitly opted out of Vintage 2014 during the annual enrollment period for that vintage, nor (b) opted out of Vintage 2019) is (0.0002) cents per kWh.

32. DEC should leverage its collaborative stakeholder meetings (Collaborative) to discuss the EM&V issues and program design issues raised in the testimony of NC Justice Center witness Neme and report the results of those discussions in the Company's 2019 DSM/EE rider filing.

33. Beginning in 2019, the Company should increase the frequency of the Collaborative meetings so that the combined DEC/Duke Energy Progress, LLC (DEP) Collaborative meets every two months.

EVIDENCE AND COCLUSIONS FOR FINDINGS OF FACT NOS. 1-2

The evidence and legal bases in support of these findings and conclusions can be found in the Application, the pleadings, the testimony, and the exhibits in this docket, as well as in the statutes, case law, and rules governing the authority and jurisdiction of this Commission. These findings are informational, procedural, and jurisdictional in nature.

Pursuant to N.C. Gen. Stat. § 62-133.9 the Commission has the authority to approve an annual rider, outside of a general rate case, for recovery of reasonable and prudent costs incurred in the adoption and implementation of new DSM and EE measures, as well as appropriate rewards for adopting and implementing those measures. Similarly, Commission Rule R8-68 provides, among other things, that reasonable and prudent costs of new DSM or EE programs approved by the Commission shall be recovered through the annual rider described in N.C. Gen. Stat. § 62-133.9 and Commission Rule R8-69. The Commission may also consider in the annual rider proceeding whether to approve any utility incentive (reward) pursuant to N.C.G.S. § 62-133.9(d)(2)a through c.

Commission Rule R8-69 outlines the procedure whereby a utility applies for and the Commission establishes an annual DSM/EE rider. Commission Rule R8-69(a)(2) defines a DSM/EE rider as

> a charge or rate established by the Commission annually pursuant to N.C. Gen. Stat. § 62-133.9(d) to allow the electric public utility to recover all reasonable and prudent costs incurred in adopting and implementing new demand-side management and energy efficiency measures after August 20, 2007, as well as, if appropriate, utility incentives, including net lost revenues.

Commission Rule R8-69(c) allows a utility to apply for recovery of incentives for which the Commission will determine the appropriate ratemaking treatment.

Section 62-133.9 of the North Carolina General Statutes, along with Commission Rules R8-68 and Rule R8-69, establish a procedure whereby an electric public utility files an application in a separate docket for the Commission's approval of an annual rider for recovery of reasonable and prudent costs of approved DSM and EE programs as well as appropriate utility incentives, potentially including "[a]ppropriate rewards based on capitalization of a percentage of avoided costs achieved by demand-side management and energy efficiency measures." Consistent with this provision, as well as the Commission-approved Revised Sub 1032 Mechanism, the Company filed an application for approval of such annual rider (Rider 10) and the cost recovery and utility incentives the Company seeks through Rider 10 are based on the Company recovering DSM/EE program costs, NLR (net of found revenues), and a PPI incentive related to the DSM and EE programs approved in the Sub 1032 Order and those approved following the Sub 1032 Order.[1] Recovery of these costs and utility incentives is also consistent with N.C. G.S. § 62-133.9,

[1] The programs approved by the Commission following the Sub 1032 Order are as follows: Smart Energy in Offices (formerly, the Smart Energy Now Pilot), which was approved in Docket No. E-7, Sub 961 on August 13, 2014; Small Business Energy $aver, which was approved on August 13, 2014 in Docket No.-E-7, Sub 1055; the

Rule R8-68, and Rule R8-69. Therefore, the Commission concludes that it has the authority to consider and approve the relief the Company is seeking in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence for this finding can be found in DEC's Application, the testimony and exhibits of Company witnesses Evans and Miller, the testimony of Public Staff witness Williamson, and various Commission orders.

DEC witness Miller's testimony and exhibits show that the Company's request for approval of Rider 10 is associated with the Sub 1032 portfolio of programs, as well as the programs approved by the Commission after the Sub 1032 Order. The direct testimony and exhibits of DEC witness Evans listed the applicable DSM/EE programs as follows: Energy Assessments; EE Education; Energy Efficient Appliances and Devices; Residential Smart $aver EE; Multi-Family EE; MyHER; Income-Qualified EE and Weatherization; Power Manager; Non-Residential Smart $aver Energy Efficient Food Service Products; Non-Residential Smart $aver Energy Efficient HVAC Products; Non-Residential Smart $aver Energy Efficient IT Products; No-Residential Smart $aver Energy Efficient Lighting Products; Non-Residential Smart $aver Energy Efficient Process Equipment Products; Non-Residential Smart $aver Energy Efficient Pumps and Drives Products; Non-Residential Smart $aver Custom; Non-Residential Smart $aver Custom Energy Assessments; PowerShare; PowerShare Call Option (canceled effective January 31, 2018); Small Business Energy $aver; Smart Energy in Offices (canceled effective June 30, 2018); EnergyWise for Business; and Non-Residential Smart $aver Performance Incentive.

In his testimony, Public Staff witness Williamson also listed the DSM/EE programs and pilots for which the Company seeks cost recovery and noted that each of these programs and pilots has received approval as a new DSM or EE program and is eligible for cost recovery in this proceeding under N.C.G.S. § 62-133.9.

Thus, the Commission finds and concludes that each of the programs and pilots listed by witnesses Evans and Williamson has received Commission approval as a new DSM or EE program, or pilot and is, therefore, eligible for cost recovery in this proceeding under N.C.G.S. § 62-133.9.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4 – 8

The evidence in support of these findings can be found in the testimony and exhibits of DEC witness Evans and Public Staff witness Williamson, and the testimony of NC Justice Center witness Neme.

Business Energy Report Pilot, which was approved in Docket No. E-7, Sub 1081 on August 19, 2015; EnergyWise for Business, which was approved in Docket No. E-7, Sub 1093 on October 27, 2015; and Smart Energy in Healthcare, which was approved in Docket No. E-7, Sub 1141 on July 25, 2017. The Company's Energy Management Information Services Pilot, Business Energy Report Pilot, Residential Appliance Recycling program, PowerShare CallOption, Smart Energy in Healthcare program, and Smart Energy in Offices have since been discontinued.

DEC witness Evans testified that the Company performed prospective analyses of each of its programs and the aggregate portfolio for the Vintage 2019 period, the results of which are incorporated in Evans Exhibit No. 7. DEC's calculations indicate that, with the exception of the Income-Qualified EE and Weatherization program (which was not cost-effective at the time it was approved by the Commission), the Non-Residential Smart $aver Performance Incentive, and the Residential Smart $aver EE programs, the programs within the portfolio continue to be cost-effective. Evans Exhibit 7 shows that the projected portfolio cost-effectiveness is 2.46 under the Utility Cost (UC) test and 1.98 under the TRC.

Public Staff witness Williamson stated in his testimony that he reviewed DEC's calculations of cost-effectiveness under each of the four standard cost-effectiveness tests -- the UC, TRC, Participant, and Ratepayer Impact Measure (RIM) tests. He indicated that under DEC's calculations, each program was cost-effective under both the UC and the TRC tests, with the exception of the Income-Qualified EE and Weatherization program (TRC of 0.83 and UC of 0.19), the Residential Smart $aver EE program (formerly, HVAC EE) (TRC of 0.59 and UC of 0.94), the EnergyWise for Business program (TRC of 1.21 and UC of 0.83), and the Non-Residential Smart $aver Performance Incentive (TRC of 0.81 and UC of 2.70). Witness Williamson noted that while many programs continue to be cost effective, the TRCs calculated by the Company for all programs have decreased since the 2017 DSM/EE rider proceeding, mainly due to the changes in avoided cost rates. Witness Williamson stated that the decreasing cost-effectiveness is also partially attributable to anticipated unit savings being lower than expected as determined through EM&V of the programs. Also, as programs mature, baseline standards increase, or avoided cost rates decrease, and it becomes more difficult for a program to produce cost-effective savings.

Company Witness Evans also testified that the avoided cost rates used in the 2019 portfolio projection were significantly lower than those employed in the Sub 1130 proceeding. Witness Evans further noted that the reductions in avoided costs lowered cost-effectiveness of all of the Company's DSM and EE programs, as well as DEC's portfolio as a whole.

NC Justice Center witness Neme testified that DEC's DSM/EE portfolio was very cost-effective, producing $2.46 in supply-cost savings for every dollar spent. He noted that cost-effectiveness tests are dependent on avoided cost rates and would need to be updated as avoided costs change.

Public Staff witness Williamson testified that the Public Staff's calculations of cost-effectiveness provide no capacity value for years in which DEC's underlying IRP shows zero capacity need. Using this specification, witness Williamson determined that in addition to the Income-Qualified EE and Weatherization, Residential Smart $aver EE, and the Non-Residential Smart $aver Performance Incentive programs, the Non-Residential Smart $aver Custom/Assessments and EnergyWise for Business programs are also not projected to be cost-effective under the TRC test. However, witness Williamson stated that the portfolio of programs seems generally to be performing satisfactorily.

NC Justice Center witness Neme testified that DEC's DSM/EE portfolio is very cost-effective, demonstrating that DSM/EE programs are a least cost resource for meeting consumers' electricity needs. Based on DEC's estimated UCT benefit-cost ratio, he stated that for every dollar that DEC spends on its programs, it is eliminating the need to spend $2.46 on new power plants, the fuel to run those power plants, new power lines, and other investments otherwise needed to supply electricity to homes and businesses. DEC's analysis also suggests that the programs are very cost-effective under the TRC test, with a benefit cost-ratio of approximately 2 to 1. Witness Neme added that since 2014, DEC's programs have saved enough energy at the time of system peak to eliminate the need for the equivalent of more than four natural gas peaker power plants.

As a whole, the Commission concludes that DEC's portfolio of DSM and EE programs is cost-effective and eligible for inclusion in Rider 10. The Commission makes specific findings and conclusions as to the individual programs that DEC and/or the Public Staff have identified as not being cost-effective and discusses each below.

Income-Qualified EE and Weatherization Program

Witness Williamson testified that the Company's Income-Qualified EE and Weatherization Program - Low-Income was hit with a major decrease in cost-effectiveness due largely to the update of the avoided cost sources. However, witness Williamson explained that, as a matter of policy, low-income programs are not required to meet the cost-effectiveness test thresholds that other programs must meet in order to be considered for continuation, because they are intended to provide EE measures to a sector of customers who would not otherwise participate in an EE program on their own.

Pursuant to Paragraph 19 of the Mechanism (which provides an exception for low-income programs and other non-cost-effective programs with similar societal benefits), the Income-Qualified EE and Weatherization Program is not required to pass the TRC or UCT tests in order to be eligible for inclusion in the Company's portfolio. Therefore, based on the foregoing, the Commission finds and concludes that no further action by the Company is required with respect to this program.

EnergyWise for Business and Non-Residential Smart $aver Custom Energy Assessments

Witness Williamson testified that DEC's EnergyWise for Business Program is a DSM program that draws the majority of its avoided cost benefits from capacity and transmission and distribution (T&D) reductions. He acknowledged that using the Company's application of avoided capacity costs, this program is cost-effective under the TRC test. However, when using the Public Staff's methodology, this program is no longer cost-effective. Thus, according to witness Williamson, pursuant to Paragraph 23B of the Mechanism, the Company should provide a discussion of the actions being taken to maintain or improve cost-effectiveness, or alternatively, its plans to terminate the program. He recommended further that pursuant to Paragraph 23C of the Mechanism, if this program shows a prospective TRC of less than 1.00 in next year's DSM/EE rider proceeding, the Company should include a discussion of what actions it has taken to improve cost-effectiveness.

Witness Williamson explained that the Non-Residential Smart $aver Custom Energy Assessments and Non-Residential Smart $aver Custom programs were filed separately in the last proceeding, but since then, the Company has decided to combine these two programs for purposes of program performance due to their similarities, including target participants. Under the combined efforts, the cost-effectiveness of these two programs shows a TRC greater than 1.00; however, when applying the Public Staff's methodology, the combined program is no longer cost-effective. As a result, witness Williamson recommended that, pursuant to Paragraph 23B of the Mechanism, the Company should provide a discussion of the actions being taken to maintain or improve cost-effectiveness, or alternatively, its plans to terminate the program. He recommended further that, pursuant to Paragraph 23C of the Mechanism, if the combined program shows a prospective TRC of less than 1:00 in next year's DSM/EE rider proceeding, the Company should include a discussion of the actions taken to improve cost-effectiveness.

In his rebuttal testimony, witness Evans made it clear that the Company does not agree with the application of zero avoided capacity cost values proposed by the Public Staff for the determination of program cost-effectiveness. He reiterated that while use of the Public Staff's proposed zero avoided capacity cost values would render the Non-Residential Smart $aver Custom Energy Assessments and EnergyWise for Business programs non-cost-effective, these programs are considered to be cost-effective under the avoided cost rates applied by the Company. He concluded that because these programs are cost-effective under the Company's methodology, Paragraph 23B of the Mechanism does not apply.

The Commission finds and concludes, based on all of the evidence in the record, that the Non-Residential Smart $aver Custom Energy Assessments and EnergyWise for Business programs are cost-effective under DEC's calculation of avoided capacity costs. Consistent with the Commission's findings regarding the determination of avoided capacity costs, the Commission further finds and concludes that these programs are cost-effective, and no further action is required by the Company.

<u>Residential Smart $aver EE Program</u>

The Company's Residential HVAC EE – Air Conditioning Program (HVAC EE) was originally approved as a new EE program in the Sub 1032 Order. It includes EE measures associated with duct insulation and sealing, attic insulation and air sealing, tune-up of existing HVAC systems, and replacement of existing central air conditioning and heat pump HVAC systems with more efficient units. The program replaced the original Residential Smart $aver program that was approved in the Sub 831 Order and included many of the same measures.

On October 2, 2015, DEC filed an application seeking approval of modifications to the HVAC EE Program, including changes to the incentive structure and addition of a referral channel to guide interested customers to one or more DEC-approved HVAC contractors who have paid DEC a fee to be on the referral list. In its comments, the Public Staff raised the concern that the program as a whole, and some of the individual measures, were not projecting cost-effectiveness under the TRC test. The Company responded that the cost-effectiveness results were due to elevated participant costs due to the high upfront cost of efficient HVAC equipment; DEC predicted that, as the cost of HVAC equipment declined, the TRC result would improve. The Public Staff and DEC reached an agreement that the Public Staff would support approval of the modifications, as amended by the Public Staff, with the exception that if the program did not have a projected TRC greater than 1.0 by March 1, 2017, then the program would terminate effective March 31, 2017. The Company also agreed that if the projected TRC was lower than 1.0 as of March 1, 2017, or if the actual TRC for 2016 and the early part of 2017 was below 1.0, DEC would refund any Vintage 2016 and 2017 incentives associated with the program (i.e., PPI or net lost revenues) that DEC had collected in rates. The Commission approved the agreed-to program modifications with these conditions on February 9, 2016.

In the Sub 1130 proceeding, the projected TRC score for the HVAC EE Program in Vintage 2018 was 0.99. Public Staff witness Jack L. Floyd testified that approximately 99% of the participation in the HVAC replacement measures of the program was through the non-referral channel. He recommended that the Company either terminate the program or modify it to transition away from non-referral channel measures that are not cost-effective under the TRC and instead focus more on cost-effective referral measures. The Company agreed with this recommendation.

On July 20, 2017, the Company filed an application seeking approval of modifications to the HVAC EE Program and the Residential EE Appliances and Devices Program. (*See* Public Staff Evans Cross Examination Ex. 7, p. 1.) The proposed modifications included the removal of measures that were not cost-effective, restructuring the incentives for several of the measures that would remain, and generally aligning the program with a similar program offered by DEP. DEC proposed to consolidate the surviving measures from both programs into the Residential Smart $aver EE Program. The projected TRC for the Residential Smart $aver EE Program at the time of the filing was 1.08. The Public Staff stated that the program overall appeared to be cost-effective, but also noted that measures offered through the non-referral channel were not cost-effective. The Public Staff also acknowledged the Company's concerns related to the perception of discrimination and that the program would be considered a "pay for play" by HVAC contractors if the non-referral channel were eliminated. However, the Public Staff observed that as long as the Company continued to offer measures through the non-referral channel, the program would continue to be marginally cost-effective. The Commission approved the proposed modifications on September 11, 2017.

In his direct testimony in this proceeding, witness Evans testified that despite several modifications, the Residential Smart $aver EE Program continues to struggle to maintain cost-effectiveness. More specifically, he explained that during 2016 and 2017, the Company made a number of changes to the program to address the erosion in the program's cost-effectiveness caused by advancement in efficiency standards and the associated lower incremental savings associated with exceeding the new standards. These program changes, which included redesign of the program to include a referral channel that reduced program costs, proved successful in returning the program to cost-effectiveness in 2017 and 2018. Unfortunately, with the application of the new lower avoided costs in 2019, the program is again projecting to no longer be cost-effective. According to witness Evans, the Company is actively working to evaluate additional programmatic changes, such as the Public Staff's recommendation to transition to referral channel measures, that would offset the decline in avoided costs and make the program cost-effective in 2019 and beyond.

Witness Williamson testified that the Residential Smart $aver EE program has struggled to achieve cost-effectiveness for several years because of (1) higher efficiency standards mandated by the federal government, which have increased baselines against which savings impacts have been measured, and (2) the need for large participant incentives to overcome the upfront out-of-pocket costs to participants. He asserted that the two sets of program modifications approved by the Commission have only made marginal improvements to cost-effectiveness. He explained that the main drivers decreasing cost-effectiveness continue to be the tighter efficiency standards and decreases in the avoided cost benefits.

Witness Williamson noted that DEC has expressed a strong desire to continue offering a residential HVAC replacement program. With HVAC being one of the largest energy-consuming appliances in the home, witness Williamson agreed that an EE program that encourages adoption of high efficiency HVAC equipment is a fundamental program for a utility's EE portfolio. He also acknowledged that is it critical to maintain a good vendor network that provides customers with accurate, reliable information on HVAC energy consumption and other assistance.

Witness Williamson stated that while this program has continually struggled to maintain cost-effectiveness, a residential HVAC program is a cornerstone program for any electric utility. He testified that he thinks it is preferable that the Company suspend rather than terminate the program until it can determine what is necessary for this program to achieve and maintain cost-effectiveness. His recommendation is that the program be suspended effective December 31, 2018.

Witness Neme encouraged the Company to focus on promoting longer-lived major measures, such as those included in the Residential Smart $aver EE Program. He suggested that the Company make efforts to increase participation in rebate offers for high-efficiency heat pumps, central air conditioners, heat pump water heaters, pool pumps, attic insulation, air sealing, and duct sealing. He stated that there should be significant savings potential from these measures as they address the largest electricity end-uses in homes.

In his rebuttal testimony, witness Evans responded to witness Williamson's recommendation that the Residential Smart $aver Program be suspended. He testified that the Company believes that suspending the only program that offers assistance for making the largest single energy user in the home, a customer's HVAC system, more energy efficient does not seem reasonable, especially when the decision to make an investment in HVAC equipment only comes around once every fifteen years. Furthermore, witness Evans pointed out that the recommended suspension of the program does not take into consideration the Company's relationships with HVAC contractors. He anticipates that the proposed suspension would likely erode trust and engagement, making it more like a termination than a suspension and also making it difficult to offer similar types of programs that would require trade ally support in the future.

In the past, when the program's cost-effectiveness has struggled due to efficiency standard changes, the Company has demonstrated the ability to effectively modify the program to restore cost-effectiveness and should have the opportunity to attempt to restore the cost-effectiveness of the program that was eroded by a reduction in avoided costs. As Witness Evans testified, "We have been resilient with attempts to make changes to keep that program viable. We have had one thing after another and that's just the nature of things with the [decrease in] avoided cost... [and increase in] incremental prices associated with the enhanced energy efficient equipment, so it's been difficult...but we continue to try."

The Company is currently investigating several opportunities to increase the cost-effectiveness of the program, including the following:

1. While the Company does have some concerns with respect to the Public Staff's recommendation to move the program to an all referral structure, the Company is not opposed to adopting this proposal so long as the Commission deems it appropriate;
2. Performing updated studies of the incremental costs actually being paid by customers to adopt higher efficiency equipment, in order to ensure these costs are reflective of the current market; and
3. Updating the measure mix, measure designs, and requirements that may be able to be removed/altered, thus lowering product cost to customers and increasing the TRC score.

Witness Evans concluded that the Company is confident that there is a solution available that will lead to a cost-effective program and that shutting down the current operations without an appropriate time frame for planning and adjustment is not the best answer for DEC's customers. In response to questioning from counsel for NC Justice Center, witness Evans explained the importance of the Company's trade ally network to the success of a residential HVAC EE program. He noted that while trade allies provide advice to customers relating to energy efficient HVAC systems, non-trade allies tend to provide less emphasis on high efficiency equipment. He testified that the Company's trade allies go through a certification process to ensure customer satisfaction and quality. The Company also uses feedback from customers to "make sure [DEC has] a high quality group of folks making those installations and again be assured that they are at least providing customers with information related to high efficiency options." Witness Evans emphasized that DEC wants to maintain trust with these contractors so that they will remain available to do HVAC EE upgrades in the future: "if you were to drop our Trade Ally Network and then try to reestablish it a year later, I think that would be very difficult."

Witness Evans also testified that the Company is in the process of beginning a new analysis of the incremental price of higher efficiency equipment in the marketplace. The Company expects that as higher efficiency equipment becomes more available in the marketplace and there is additional competition, prices will go down. As such, a more updated detailed cost-effectiveness analysis that takes into account these anticipated price decreases would likely result in an increase in the program's TRC score.

In response to cross-examination from counsel for the Public Staff, witness Evans acknowledged that in the Sub 1130 rider proceeding, witness Floyd recommended that the Company modify the program to transition from non-referral channel measures to be more heavily focused on referred measures. He also acknowledged that, in the same proceeding, the Company agreed to modify the program design to improve the ratio of customers participating in referral measures.

While the Company did file modifications to the program shortly after the Sub 1130 proceeding designed to improve cost-effectiveness, DEC did not completely eliminate the non-referral channel. Witness Evans explained that while the Company does not object to witness Floyd's recommendation and is focused on increasing participation in the referral channel, it has concerns with eliminating the non-referral channel altogether: "We are concentrating on referred measures with trade allies;" "however, we did not go to complete referral."

As DEC stated in response to a Public Staff data request:

> While the Company does not disagree with the changes proposed by the Public Staff in the last case, Docket No. E-7, Sub 1130, regarding the elimination of the non-referral channel provided in the Residential Smart $aver EE program, the Company did have concerns regarding the broader trade ally network response to such a drastic programmatic change. As the Program's cost-effectiveness is of an ongoing concern for both the Public Staff and the Company, the Company is not adverse [sic] to adopting the Public Staff's recommendation to eliminate the non-referral channel. The Company would prefer that the Public Staff, in the context of the current proceeding, request that the Commission order the Company to make this Program change. If the Commission approves the Public Staff's request, which the Company does not plan to object to, the Company will file the changes, in the form of a compliance tariff within 60 days of the Commission's Order.

Witness Evans clarified that the "concerns" about the impact on trade allies that the Company referred to in this data request response are the same as those stated in the Commission's Order approving the 2017 program modifications:

> DEC indicated to the Public Staff that the Company will continue to provide incentives for measures installed outside of the referral channel because of concerns that converting the [Residential Smart $aver EE Program] to a 'referral only' program would create a 'pay for play' environment. DEP [sic] believes the proposed modifications will increase participation in the referral-based delivery channel.

The 2017 modifications have, in fact, improved the ratio of customers participating in referral measures, as promised by witness Duff and as stated above. According to witness Williamson, new data provided by the Company in this proceeding suggest that participation is shifting from the non-referral to the referral channel, with approximately 70% of the current participation coming through the referral channel (versus only 1% of the participation coming through the referral channel as of last year's proceeding).

In response to questions relating to who bears the risk with respect to the Residential Smart $aver EE Program, witness Evans acknowledged that while ratepayers do receive benefits from the program, they do bear some risk if the program continues to struggle with cost-effectiveness. However, he pointed out that this is a shared risk – if the program is not cost-effective, the Company's PPI is adversely impacted. He testified that if the Company were looking at incentives in isolation, the motivation would perhaps be to remove it from the portfolio. However, the Company has faith in the program in the long run and continues to believe it is a critical piece of its overall portfolio.

Witness Evans concluded his testimony relating to the Residential Smart $aver Program by explaining why the Company thinks it is important to offer a residential HVAC program:

> Again, it's the largest energy user in a domicile. It lasts 15 years. A customer can make a decision today to go baseline or to go to a higher efficiency unit. We're talking about long life benefits and this is the opportunity to do it now ... it's very important because it impacts so many homes and we have an opportunity here to provide long lasting energy efficiency benefits, thus our desire to maintain the program.

The Commission agrees with witnesses Evans, Neme, and Williamson that a residential HVAC program is an important program for an electric utility to offer as part of its DSM/EE portfolio. All three witnesses testified that the HVAC is one of the largest – if not, the largest – energy-consuming appliances in the home. In addition, as stated by witnesses Neme and Evans, the long measure life of an HVAC unit makes it particularly important to maintain this program as part of the Company's portfolio. A rebate for a high-efficiency HVAC unit could lead to savings for many years to come.

Both witnesses Evans and Williamson also recognize that DEC's relationship with its trade ally network – i.e., the HVAC contractors that service participants in the Residential Smart $aver EE Program – is crucial to maintaining a viable HVAC program. The Commission agrees with witness Evans that a suspension of the program would put those relationships at risk, which could jeopardize the entire program. Accordingly, the Commission finds and concludes that the Residential Smart $aver EE Program should not be suspended at this time. That said, the Commission is mindful of the Public Staff's concerns that ratepayers not pay for non-cost-effective programs. Based on the Company's persistent efforts to maintain the viability of the program through program modifications, as well as the negative impact on the Company's PPI if the program continues to struggle to maintain cost-effectiveness, the Commission believes that DEC is highly motivated to continue to find ways to improve cost-effectiveness.[1] To that end, witness Evans outlined a number of ways in which the Company could modify the Residential Smart $aver EE Program to improve cost-effectiveness. Thus, the Commission directs the Company (1) to propose modifications to this program no later than October 31, 2018, with the goal of restoring the TRC score to 1.0 or greater, and (2) to include a discussion of the impact those modifications and other actions it has taken to improve cost-effectiveness in next year's DSM/EE rider proceeding.

Non-Residential Smart $aver Performance Incentive Program

Witness Evans testified that the forecasted 2019 TRC score for DEC's Non-Residential Smart $aver Performance Incentive Program is 0.81 and the UCT score is 2.70. He explained that while the TRC score may be viewed as less than optimal in isolation, it is important to note that this program is largely an extension of the custom portion of the Non-Residential Smart $aver Program. In particular, the Performance Incentive Program encompasses energy saving measures related to new technologies, unknown building conditions and system constraints, as well as uncertain operating circumstances, occupancy, or production schedules. Witness Evans testified

[1] Counsel for the Public Staff suggested that in order to show the faith that it has in the future of this program, the Company should agree to pick up a portion of the program costs and the net lost revenues to the extent that the program is not cost-effective. The Commission finds that because failing cost-effectiveness results in a hit to the Company's PPI, DEC already has "skin in the game" and there is no need to apply additional financial pressure to motivate the Company to pursue program modifications to improve cost-effectiveness.

that, as a result, energy savings are difficult to project with any level of accuracy. In addition, the Company believes that if this program were no longer offered as part of the Company's EE portfolio, additional opt-out eligible customers may elect to opt out of the EE portion of Rider EE as a result. Witness Evans also noted that, due to the nature of the program, the risk of overcompensating participants at the expense of other customers or, conversely, undercompensating participants for their EE improvements, is limited. He concluded that the Company believes that this program is an essential element of its EE portfolio and that its cost-effectiveness results will improve.

Witness Williamson testified that the Non-Residential Smart $aver Performance Incentive Program was approved in the fall of 2016 and launched in January 2017. In the Sub 1130 proceeding, this program was not cost-effective but was still too new to assess its full potential. This year, it is again not cost-effective, but because of its status last year, witness Williamson considers this program to fall under paragraph 23B of the Mechanism. Thus, he recommended that in its rebuttal or supplemental testimony in this proceeding, the Company provide a discussion of the actions being taken to maintain or improve cost-effectiveness, or alternatively, its plans to terminate the program. Further, if this program is again not cost-effective at the time of the next rider filing, he recommended that the Company should include a discussion in that proceeding of the actions taken to improve cost-effectiveness pursuant to Paragraph 23C of the Mechanism.

In his rebuttal testimony, witness Evans explained that the Non-Residential Smart $aver Performance Incentive Program was intended to encompass large EE-related projects with uncertainty relative to their performance – for example, projects that employ new technologies. Related program incentives are provided in installments based on actual savings. In this manner, participants are properly incentivized for their EE-related investments and other customers are shielded from the impacts of overstated performance. That said, very few projects are appropriate for participation in the program. The 0.81 TRC test score reflected in Evans Exhibit 7 was based upon participation forecasts and costs used in the Company's 2016 program filing. During 2017, only two projects were involved. Currently, there are 12 projects underway in the Company's North Carolina service territory. The Company's estimated TRC score for this program, based on these and other projects under review, will exceed 1.75.

Based upon the foregoing, the Commission finds and concludes that this program does not require additional scrutiny at this time, due to both the short time it has been in place and the anticipated improvement in cost-effectiveness results. Nevertheless, if the program does not project cost-effectiveness for Vintage 2020, pursuant to Paragraph 23B of the Mechanism, the Company shall provide a discussion of the actions being taken to maintain or improve cost-effectiveness, or alternatively, its plans to terminate the program in its next DSM/EE rider proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9-11

The evidence in support of these findings can be found in the testimony and exhibits of DEC witness Evans and the testimony of Public Staff witness Williamson.

DEC witness Evans testified regarding the EM&V process, activities, and results presented in this proceeding. He explained that the EMF component of Rider 10 incorporates actual customer participation and evaluated load impacts determined through EM&V and applied pursuant to the EM&V Agreement. In addition, actual participation and evaluated load impacts are used prospectively to update estimated NLR. In this proceeding, the Company submitted, as exhibits to witness Evans' testimony, detailed completed EM&V reports or updates for the following programs: PowerShare 2016; Non-Residential Smart $aver Energy Efficient Products and Assessment - Custom 2014-2015; MyHER 2015-2016; Power Manager Load Control Service 2016; Small Business Energy $aver 2014-2016; Non-Residential Smart $aver Energy Efficient Products and Assessment - Assessment 2014-2016; EnergyWise for Business 2016; Multi-Family EE 2014-2016; Non-Residential Smart $aver Energy Efficient Products and Assessment - Prescriptive 2013-2015; Residential Energy Efficient Appliances and Devices - Save Energy and Water Kit: 2016; Energy Efficient Appliances and Devices - Free LED 2016-2017; and Smart Energy in Offices 2014-2016.

In his testimony, Public Staff witness Williamson testified that to the extent recommendations made by the Public Staff regarding EM&V in prior DSM/EE rider proceedings were applicable to the EM&V reports filed in this proceeding, the reports incorporated those recommendations and that it was his understanding that future reports would incorporate those recommendations as well. He stated that with the exception of the EM&V reports for the Non-Residential Smart $aver Custom and MyHER programs, the program vintages for which EM&V reports were filed in this proceeding should be considered complete and do not require any adjustment to the impacts at this time. Witness Williamson recommended that acceptance of the report for the Non-Residential Smart $aver Custom program be postponed until a revised report containing an adjusted net-to-gross scoring scale is filed in the next rider proceeding. He also recommended that acceptance of the report for the MyHER program be postponed until DEC's 2019 DSM/EE rider proceeding so that the Public Staff can complete its review of the savings estimates. Public Staff witness Williamson noted that the EM&V reports for the Multifamily EE, Non-Residential Smart $aver Prescriptive Incentive, and Small Business Energy $aver programs, which had previously been filed in the 2017 DSM/EE rider proceeding, had appropriately incorporated the Public Staff's previous recommendations.

NC Justice Center witness Neme testified that the EM&V framework used by DEC is well-conceived and that his review of the EM&V reports suggests that studies have been conducted professionally.

With the exception of the recommendations made by Public Staff witness Williamson regarding the EM&V for the Non-Residential Smart $aver Custom and MyHER programs (none of which were disputed by DEC), no party contested the EM&V information submitted by the Company. The Commission therefore finds that the EM&V reports filed as Evans Exhibits A, D, E, F, G, H, I, J, K, and L are acceptable for purposes of this proceeding and should be considered complete for purposes of calculating program impacts; that the EM&V report for the Non-Residential Smart $aver Custom program (Evans Exhibit B) be revised as recommended by witness Williamson and filed in the next rider proceeding; and that acceptance of the EM&V for the MyHER program (Evans Exhibit C) be postponed until DEC's 2019 DSM/EE rider proceeding so that the Public Staff can complete its review of the savings estimates.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-13

The evidence in support of these findings can be found in the Sub 938 Second Waiver Order; the Sub 1032 Order; the testimony of Company witnesses Miller and Evans; and the testimony of Public Staff witness Maness. The rate period and the scope of the EMF components of Rider 10 are consistent with the Commission's ruling in the Sub 938 Second Waiver Order and the Sub 1032 Order, and are uncontroverted by any party.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 14-31

The evidence in support of these findings and conclusions can be found in the Sub 831 Order, Sub 831 Found Revenues Order, Sub 938 Waiver Order, Sub 938 Second Waiver Order, Sub 979 Order, Sub 1032 Order, and Sub 1130 Order; as well as in the Company's Application; the direct and rebuttal testimony and exhibits of Company witnesses Miller, Evans, Duff and Stevie; and the testimony and exhibits of Public Staff witnesses Maness, Williams and Williamson.

On March 7, 2018, DEC filed its Application seeking approval of Rider 10, which includes the formula for calculation of Rider EE, as well as the proposed billing factors to be effective for the 2019 rate period. Company witness Miller and Public Staff witness Maness testified that the methods by which DEC has calculated its proposed Rider EE are those provided by the Sub 1032 Stipulation, the Sub 1032 Mechanism approved in the Sub 1032 Order, and the Revised Mechanism approved in Sub 1130. Witness Miller provided an overview of the Revised Mechanism, which is designed to allow the Company to collect revenue equal to its incurred program costs[1] for a rate period, plus a PPI based on shared savings achieved by the Company's DSM and EE programs, and to recover NLR for EE programs only. She explained that the PPI is calculated by multiplying the net dollar savings achieved by the system portfolio of DSM and EE programs by a factor of 11.5%. The system amount of PPI is then allocated to North Carolina retail customer classes in order to derive customer rates. Company witness Evans explained that the calculation of the PPI is based on avoided cost savings, net of program costs, achieved through the implementation of the Company's DSM and EE programs. Witness Miller noted the revisions to the Sub 1032 Mechanism approved in Sub 1130, i.e., provisions related to the source of the avoided cost inputs used for calculating the PPI and cost-effectiveness, and requirements for programs that appear not to be cost-effective on an ongoing basis.

The Company is allowed to recover NLR associated with a particular vintage for a maximum of 36 months or the life of the measure, or until the implementation of new rates in a general rate case to the extent that the new rates are set to recover NLR. DEC witness Miller testified that for the prospective components of Rider EE, NLR are estimated by multiplying the portion of the Company's tariff rates that represents the recovery of fixed costs by the estimated North Carolina retail kilowatt (kW) and kWh reductions applicable to EE programs by rate schedule, and reducing this amount by estimated found revenues. The fixed cost portion of the tariff rates is calculated by deducting the recovery of fuel and variable operation and maintenance costs from the tariff rates. The NLR totals for residential and non-residential customers are then

[1] Rule R8-68(b)(1) defines "program costs" as all reasonable and prudent expenses expected to be incurred by the electric public utility, during a rate period, for the purpose of adopting and implementing new DSM and EE measures previously approved pursuant to Rule R8-68.

reduced by North Carolina retail found revenues computed using the weighted average lost revenue rates for each customer class. Lost revenues associated with vintages through the test period of the Company's current general rate case proceeding in Docket No. E-7, Sub 1146 were removed from the prospective period as of May 1, 2018, assuming the NLR would be recovered through new base rates. All amounts will be trued up during the next EMF period. For the EMF components of Rider EE, NLR are calculated by multiplying the fixed cost portion of the tariff rates by the actual and verified North Carolina retail kW and kWh reductions applicable to EE programs by rate schedule, and reducing this amount by actual found revenues.

Witness Evans described how, in accordance with the Commission's Sub 831 Found Revenues Order and the Sub 1032 Stipulation, DEC reduces NLR by net found revenues. Additionally, he stated that the Company has continued the practice the Commission approved in Docket No. E-7, Sub 1073 for purposes of that proceeding of reducing net found revenues by the monetary impact (negative found revenues) caused by reductions in consumption resulting from the Company's current initiative to replace Mercury Vapor lights with Light Emitting Diode (LED) fixtures.

In each of its annual rider filings, DEC performs an annual true-up process for the prior calendar year vintages. The true-up will reflect actual participation and verified EM&V results for the most recently completed vintage, applied in accordance with the EM&V Agreement. The Company expects that most EM&V will be available in the period needed to true-up each vintage in the following calendar year. If any EM&V results for a vintage are not available in time for inclusion in DEC's annual rider filing, however, the Company will make an appropriate adjustment in the next annual filing.

Under the Sub 1032 Stipulation, as witness Miller explained, deferral accounting may be used for over- and under-recoveries of costs eligible for recovery through the annual DSM/EE rider. The balance in the deferral accounts, net of deferred income taxes, may accrue a return at the net-of-tax rate of return approved in the Company's then most recent general rate case. She testified that the methodology used for the calculation of interest shall be the same as that typically utilized for the Company's Existing DSM Program Rider proceedings. Pursuant to Commission Rule R8-69(c)(3), the Company will not accrue a return on NLR or the PPI.

Under the Sub 1032 Stipulation, as with the Sub 938 First Waiver Order and the Sub 831 Pilot, qualifying non-residential customers may opt out of the DSM and/or EE portion of Rider EE during annual election periods. Rider EE will be charged to all customers who have not elected to opt out during an enrollment period and who participate in any vintage year of programs, and these customers will be subject to all true-up provisions of the approved Rider EE for any vintage in which the customers participate. Company witness Miller explained that the Revised Mechanism affords an additional opportunity for participation, whereby qualifying customers may opt in to the Company's EE and/or DSM programs during the first five business days of March. Customers who elect to begin participating in the Company's DSM and/or EE programs during the special "opt-in period" during March of each year will be retroactively billed the applicable Rider EE amounts back to January 1 of the vintage year, such that they will pay the appropriate Rider EE amounts for the full rate period.

Witness Miller explained that the billing factors are computed separately for DSM and EE measures by dividing the revenue requirements for each customer class, residential and non-residential, by the forecasted sales for the rate period for the customer class. For non-residential rates, the forecasted sales exclude the estimated sales to customers who have elected to opt-out of paying Rider EE. The non-residential billing factors are separately computed for each vintage.

Company witness Miller testified that program costs and incentives for EE programs targeted at retail residential customers across North Carolina and South Carolina are allocated to the North Carolina retail jurisdiction based on the ratio of North Carolina retail kWh sales (grossed up for line losses) to total retail kWh sales (grossed up for line losses), and then recovered only from North Carolina retail residential customers. Revenue requirements related to EE programs targeted at retail non-residential customers across North Carolina and South Carolina are allocated to the North Carolina retail jurisdiction based on the ratio of North Carolina retail kWh sales (grossed up for line losses) to total retail kWh sales (grossed up for line losses), and then recovered from only North Carolina retail non-residential customers. The portion of revenue requirements related to NLR is computed based on the kW and kWh savings of North Carolina retail customers.

For DSM programs, witness Miller noted, the aggregated revenue requirement for all retail DSM programs targeted at both residential and non-residential customers across North Carolina and South Carolina is allocated to the North Carolina retail jurisdiction based on the North Carolina retail contribution to total retail peak demand. Both residential and non-residential customer classes are allocated a share of total system DSM revenue requirements based on each group's contribution to total retail peak demand.

The allocation factors used in DSM/EE EMF true-up calculations for each vintage are based on the Company's most recently filed Cost of Service studies at the time that the Rider EE filing incorporating the true-up is made. If there are subsequent true-ups for a vintage, the allocation factors used will be the same as those used in the original DSM/EE EMF true-up calculations.

Witness Miller explained that DEC calculates one integrated (prospective) DSM/EE rider and one integrated DSM/EE EMF rider for the residential class, to be effective each rate period. The integrated residential DSM/EE EMF rider includes all true-ups for each applicable vintage year. Given that qualifying non-residential customers can opt-out of EE and/or DSM programs, DEC calculates separate DSM and EE billing factors for the non-residential class. Additionally, the non-residential DSM and EE EMF billing factors are determined separately for each applicable vintage year, so that the factors can be appropriately charged to non-residential customers based on their opt-in/out status and participation for each vintage year.

Prospective Components of Rider 10

DEC witness Miller testified that Rider 10 consists of four components: (1) a prospective Vintage 2019 component designed to collect program costs and the PPI for DEC's 2019 vintage of DSM programs; (2) a prospective Vintage 2019 component to collect program costs, the PPI, and the first year of NLR for DEC's 2019 vintage of EE programs; (3) a prospective Vintage 2018 component designed to collect the second year of estimated NLR for DEC's 2018 vintage of

EE programs; and (4) a prospective Vintage 2017 component designed to collect the third year of estimated NLR for DEC's 2017 vintage of EE programs.

Pursuant to the Sub 938 Second Waiver Order and the Sub 1032 Order, the rate period for the prospective components of Rider 10 is January 1, 2019, through December 31, 2019.

DEC witness Miller noted that lost revenues associated with Vintage 2016 were not included in the prospective component based on the assumption that new base rates would go into effect May 1, 2018.

The prospective revenue requirements for Vintage 2017 are determined separately for residential and non-residential customer classes and are based on the third year of estimated NLR for the Company's Vintage 2017 EE programs. The amounts are based on estimated North Carolina retail kW and kWh reductions and the rates approved in Docket No. E-7, Sub 1026 (Sub 1026 Rates). These rates will be trued up during the EMF period to reflect the rates approved in Sub 1146.

The prospective revenue requirements for Vintage 2018 are determined separately for residential and non-residential customer classes and are based on the second year of estimated NLR for the Company's Vintage 2018 EE programs. The amounts are based on estimated North Carolina retail kW and kWh reductions and the Sub 1026 Rates. These rates will be trued up during the EMF period to reflect the rates approved in Sub 1146.

The prospective revenue requirements for Vintage 2019 EE programs include estimates of program costs, the PPI, and the first year of NLR determined separately for residential and non-residential customer classes. The program costs and shared savings incentive are computed at the system level and allocated to North Carolina retail operations. The NLR for EE programs are based on estimated North Carolina retail kW and kWh reductions and the Sub 1026 Rates. These rates will be trued up during the EMF period to reflect the rates approved in Sub 1146.

In her direct testimony, DEC witness Miller filed testimony and exhibits reflecting a residential prospective billing factor for Rider 10 of 0.4229 cents per kWh. On June 1, 2018, DEC witness Miller filed rebuttal testimony and exhibits reflecting revised non-residential prospective billing factors[1] for Rider 10 of 0.3158 cents per kWh for non-residential Vintage 2019 EE participants, 0.0877 cents per kWh for non-residential Vintage 2019 DSM participants, 0.0695 cents per kWh for non-residential Vintage 2018 EE participants, 0.0030 cents per kWh for non-residential Vintage 2018 DSM participants, and 0.0801 cents per kWh for non-residential Vintage 2017 EE participants.

<u>EMF Components of Rider 10</u>

Rider 10 includes the following EMF components: (1) an EMF component which consists of the true-up of program participation in the Company's 2017 vintage of DSM and EE programs, updated load impacts, NLR updated for actual participation, updated found revenues, and updates to include costs for new programs approved prior to estimated filing; (2) an EMF component

[1] The non-residential billing factors were revised based on an agreement made between the Company and the Public Staff to adjust the proposed non-residential participating sales, which is addressed supra.

which consists of the true-up of Vintage 2016 avoided costs and NLR for the Company's 2016 vintage of DSM and EE programs; (3) an EMF component which consists of the true-up of Vintage 2015 avoided costs and NLR for the Company's 2015 vintage of DSM and EE programs; and (4) an EMF component which consists of the true-up of avoided costs and NLR for the Company's 2014 vintage of DSM and EE programs.

Company witness Miller testified that pursuant to the Sub 938 Second Waiver Order and the Sub 1032 Order, the "test period" for the Vintage 2017 EMF component is January 1, 2017, through December 31, 2017. As the Sub 938 Second Waiver Order allows the EMF to cover multiple test periods, the test period for the Vintage 2016 EMF component is January 1, 2016, through December 31, 2016, the test period for the Vintage 2015 EMF component is January 1, 2015, through December 31, 2015, and the test period for the Vintage 2014 EMF component is January 1, 2014, through December 31, 2014.

Witness Miller explained the updates to the Vintage 2017 estimate filed in 2016 that comprise the Vintage 2017 EMF component of Rider 10. Estimated participation for Vintage 2017 was updated for actual participation for the period January through December 2017. With regard to NLR, estimated participation for the Year 1 Vintage 2017 estimate assumed a January 1, 2017, sign-up date and used a half-year convention, while the NLR Year 1 Vintage 2017 true-up was updated for actual participation for the period January through December 2017 and actual 2017 lost revenue rates. Found revenues for Year 1 of Vintage 2017 were trued up according to Commission-approved guidelines. To reflect the results of EM&V, Vintage 2017 initial assumptions of load impacts were updated pursuant to the EM&V Agreement. Finally, while the Vintage 2017 estimate included only the programs approved prior to the filing of the estimated Vintage 2017 revenue requirement, the Vintage 2017 true-up was updated for new programs and pilots approved and implemented during Vintage 2017. For DSM programs, the Vintage 2017 true-up reflects the actual quantity of demand reduction capability for the Vintage 2017 period.

Actual year one (2017) NLR for Vintage 2017 were calculated using actual kW and kWh savings by North Carolina retail participants by customer class in 2017, based on actual participation and load impacts applied according to the EM&V Agreement. The rates applied to the kW and kWh savings are those in effect for 2017, reduced by fuel and variable operation and maintenance costs. NLR were then offset by actual found revenues for Year 1 NLR of Vintage 2017. NLR were calculated by rate schedule within the residential and non-residential customer classes.

DEC witness Miller also described the basis for the Vintage 2016 EMF component of Rider 10. She explained that avoided costs and NLR for Vintage 2016 EE programs were trued-up based on updated EM&V participation results. Avoided costs for Vintage 2016 DSM were also trued-up to correct participation results. She explained that the actual kW and kWh savings were as experienced during the period January 1, 2016, through December 31, 2016. The rates applied to the kW and kWh savings are the retail rates that were in effect during each period the lost revenues were earned, reduced by fuel and other variable costs.

DEC witness Miller explained the basis for the Vintage 2015 EMF component of Rider 10. She explained that avoided costs and NLR for Vintage 2015 EE programs were trued-up based on updated EM&V participation results. She explained that the actual kW and kWh savings were as experienced during the period January 1, 2015, through December 31, 2015. The rates applied to the kW and kWh savings are the retail rates that were in effect during each period the lost revenues were earned, reduced by fuel and other variable costs.

DEC witness Miller explained the basis for the Vintage 2014 EMF component of Rider 10. She explained that avoided costs and NLR for Vintage 2014 EE programs were trued-up based on updated EM&V participation results. She explained that the actual kW and kWh savings were as experienced during the period January 1, 2014, through December 31, 2014. The rates applied to the kW and kWh savings are the retail rates that were in effect during each period the lost revenues were earned, reduced by fuel and other variable costs.

Overall, as set forth on Miller Rebuttal Exhibit 1, the Company proposed an EMF of 0.1091 cents per kWh for its North Carolina retail residential customers, 0.2924 cents per kWh for non-residential Vintage 2017 EE participants, 0.0005 cents per kWh for non-residential Vintage 2017 DSM participants, (0.0126) cents per kWh for non- residential Vintage 2016 EE participants, (0.0015) cents per kWh for non-residential Vintage 2016 DSM participants, 0.0024 cents per kWh for non- residential Vintage 2015 EE participants, (0.0024) cents per kWh for non-residential Vintage 2015 DSM participants, (0.0061) cents per kWh for non- residential Vintage 2014 EE participants, and (0.0002) cents per kWh for non-residential Vintage 2014 DSM participants.

Public Staff's Review of Company Rider 10 Calculations

As discussed above, Public Staff witness Williamson filed testimony in this proceeding discussing several EM&V-related issues related to the Company's filing, none of which necessitates an adjustment to the Company's billing factor calculations. Public Staff witness Maness testified that his investigation of DEC's filing in this proceeding focused on whether the Company's proposed DSM/EE billing factors (a) were calculated in accordance with the Sub 1032 Settlement, the Sub 1130 Order, and the Revised Mechanism, and (b) otherwise adhered to sound ratemaking concepts and principles.

Public Staff witness Maness testified that as part of its investigation in this proceeding, the Public Staff performed a review of the DSM/EE program costs incurred by DEC during the 12-month period ended December 31, 2017. To accomplish this, the Public Staff selected and reviewed a sample of source documentation for test year costs included by the Company for recovery through the DSM/EE riders. Review of this sample was intended to test whether the costs included by the Company in the DSM/EE riders are valid costs of approved DSM and EE programs. As of the date of filing of the Public Staff testimony, Witness Maness indicated that the Public Staff had not completed its review[1]. With the exception of the two issues discussed below, witness Maness found that the Company calculated the Rider 10 billing factors in a manner consistent with N.C. Gen. Stat. § 62-133.9, Commission Rule R8-69, the Sub 1032 Settlement, the Sub 1130 Order, the Revised Mechanism, and other relevant Commission Orders.

[1] In its June 19, 2018, letter, the Public Staff indicated that it had found no further exceptions or necessary adjustments to test year (Vintage Year 2017) DSM/EE program costs.

Kilowatt Hour Sales used to Calculate Non-Residential Billing Factors

Public Staff witness Maness testified that during his review of the Company's rate calculations, he noted that for each Non-Residential vintage/factor combination for Vintage Years 2014-2018, there has been a significant decrease in the level of estimated participating kWh sales from 2018 to 2019 of approximately 12%. He explained that this decrease was attributable to a decrease in the overall non-residential kWh sales forecast of 3.90%, as well as a 6.92% increase in the Company's estimate of opt-out sales. Public Staff witness Maness testified that the net effect of these two dynamics was a substantial increase in the non-residential billing factors. He believed that the estimated participating Rider kWh sales may be understated, and recommended that the Company's proposed level of 2019 estimated kWh sales for each Non-Residential vintage/factor combination be reduced by 3.90%. Additionally, witness Maness recommended that the true-up process for Rider 10 be held open until the total actual amount of Rider 10 revenues collected can be reflected in the rate calculation process, and that the Company be allowed to recover carrying costs on any understatements of Rider 10 billing factors caused by use of the Public Staff's recommended levels of participating Rider 10 kWh sales versus the actual levels of such kWh sales, but with the understatement eligible for carrying charges limited to the difference between the Public Staff's recommended levels of participating Rider 10 kWh sales and the Company's initially proposed levels of such sales in this proceeding.

Regarding the adjustment proposed by Public Staff witness Maness to adjust non-residential participating kWh sales, DEC witness Miller indicated in her rebuttal testimony that the Company has seen an increase in the number of opt-outs each year, so it does not believe a decline is probable. She also noted that using actual opt-out sales from the test period to determine projected opt-out sales has consistently resulted in under-collections for prior Vintage Years. However, the Company would agree to the adjustment, as it would be made whole with the collection of any under-recovery and carrying charges as described by witness Maness. Witness Miller noted that this adjustment is unique and should not be used as precedent. Attached to DEC witness Miller's rebuttal testimony were exhibits incorporating this adjustment.

Witness Maness also noted that the Company has continued to use its net-of-tax rate of return to calculate the interest amount on over-recoveries in this DSM/EE Rider 10 proceeding, rather than the 10% rate normally used by the Commission for over recoveries in certain other rider proceedings. However, Witness Maness found the impact of this rate differential to be immaterial to the DSM/EE billing factors. The Public Staff reserved the right to raise this issue in the future.

Commission Conclusions Concerning kWh Sales

Based upon the foregoing, the Commission finds and concludes that the Public Staff's adjustment to non-residential participating kWh sales, as agreed to by DEC, is reasonable. The Commission concludes that it is appropriate to reduce the Company's proposed level of 2019 estimated kWh sales for each Non-Residential vintage/factor combination by 3.90%, to hold open the true-up process for Rider 10 until the total actual amount of Rider 10 revenues collected can be reflected in the rate calculation process, and to allow the Company to recover carrying costs on any understatement of Rider 10 billing factors due to the 3.90% reduction, but limit the portion of the understatement eligible for recovery to the difference between the Public Staff's recommended levels of participating Rider 10 kWh sales and the Company's initially proposed levels of such sales in this proceeding.

Avoided Costs Used in Calculating the PPI

The second issue raised by the Public Staff, as noted previously, is the appropriate level of avoided costs to be used in the determination of the PPI and calculations of cost-effectiveness. The Public Staff contends that DEC is required by the revised mechanism and the Sub 148 Order to use zero as the input when calculating the avoided capacity values for DSM/EE until 2023, when DEC's IRP shows a capacity need. As discussed by Public Staff witness Williams, under the Sub 148 Order, "new" Qualified Facilities (QFs) seeking to sell their energy and capacity to DEC will not be paid capacity payments until new capacity is needed in 2023, as identified in the Company's 2016 IRP. He pointed out that in the Sub 148 Order, the Commission noted that besides setting rates for QFs, the avoided costs are used for determining cost-effectiveness of and performance incentives for DSM/EE programs.[1] Witness Williams stated that to be consistent with the Sub 148 Order and the Revised Mechanism, determinations of cost-effectiveness and utility incentives for new and existing programs should be based on avoided capacity rates that reflect zero avoided capacity value in years prior to the identified need for new capacity in the Company's IRP (2023).

Background

Paragraphs 68 and 69 of the cost recovery mechanism, which sets out the determination of the avoided capacity costs, approved by the Commission in Sub 1032, state as follows:

> 68. For the PPI for Vintage Year 2014, the per kW avoided capacity costs used to calculate avoided cost savings shall be those reflected in the filing by Duke Energy Carolinas in Docket No. E-100, Sub 136. The per kWh avoided energy costs shall be those reflected in or underlying the most recently filed integrated resource plan (IRP)...
>
> 69. For the PPI for Vintage Years 2015, 2016, and 2017, the presumptive per kW avoided capacity costs and per kWh avoided energy costs used to calculate avoided cost savings shall be those determined pursuant to paragraph 68 above. However, if at the time of initial estimation of the PPI for each of those years, either (a) the Company's per kWh avoided energy costs calculated for the purposes of the Company's annual IRP or resource plan update filings have increased or decreased by 20% or more or (b) the Company's per kW avoided capacity costs reflected in the rates approved in the biennial avoided cost proceedings have increased or decreased by 15% or more, the avoided costs (both energy and capacity) will be updated for purposes of the DSM/EE rider proceeding.

The parties sometimes referred to the method for updating avoided costs under Paragraph 69 of the Sub 1032 Mechanism as the "trigger" or "ratchet" method, in that avoided

[1] Sub 148 Order, p. 69.

costs would remain the same unless and until the specified thresholds were met - either a change in avoided energy costs of at least 20% or a change in avoided capacity costs of at least 15% – which would then trigger an update of both avoided energy and avoided capacity costs. In addition, under Paragraph 69 of the Sub 1032 Mechanism, avoided energy costs and avoided capacity costs were derived from two different sources: the annual IRP or resource plan update filings for avoided energy and the biennial avoided cost proceedings for avoided capacity.

In the previous year's DSM/EE proceeding, Sub 1130, the Public Staff and DEC discovered that they had differing interpretations as to the appropriate avoided costs to be used in calculating Rider 9 pursuant to Paragraph 69 of the Sub 1032 Mechanism. The Public Staff believed that the "ratchet" that would cause avoided capacity and energy costs to be updated for purposes of the DSM/EE rider proceeding had been triggered for purposes of the PPI to be calculated for Vintage 2018. The Company maintained that the ratchet had not been triggered. Had avoided cost rates been updated in a manner consistent with the Public Staff's interpretation of Paragraph 69, the Vintage 2018 PPI would have been reduced by approximately $9.5 million.

The Company and the Public Staff eventually reached a comprehensive agreement (the Sub 1130 Agreement or Agreement) resolving their differences which consisted of (1) a monetary adjustment which reduced the Vintage 2018 PPI by $6,750,000 million; and (2) certain revisions to the Sub 1032 Mechanism, including the method by which avoided costs would be updated for purposes of the PPI and DSM/EE program cost-effectiveness. The Commission approved the Sub 1130 Agreement and the resulting revisions to the Sub 1032 Mechanism in Sub 1130.

Revised Paragraph 69 states as follows:

> 69. For the PPI for Vintage Years 2019 and afterwards, the program-specific per kW avoided capacity benefits and per kWH avoided energy benefits used for the initial estimate of the PPI and any PPI true-up will be derived from the underlying resource plan, production cost model, and cost inputs that generated the avoided capacity and avoided energy credits reflected in the most recent Commission-approved Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities as of December 31 of the year immediately preceding the date of the annual DSM/EE rider filing. However, for the calculation the underlying avoided energy credits to be used to derive the program-specific avoided energy benefits, the calculation will be based on the projected EE portfolio hourly shape, rather than the assumed 24x7 100 MW reduction typically used to represent a qualifying facility.

Paragraphs 19 and 23 (which govern the calculation of cost-effectiveness for program approval filings and continuing cost-effectiveness for existing programs, respectively) were also revised to reflect the same method for determining avoided costs.[1]

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[1] The Public Staff refers to the method for calculating avoided cost rates pursuant to the revised Paragraphs 19, 23, and 69 as the "PURPA method."

In the most recent Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities (Avoided Cost Proceeding) in Sub 148, the Commission was faced with whether certain changes to the previously-approved methods used to calculate avoided cost rates and to the current framework for implementing Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) were warranted given the amount and pace of the development of QFs, and in particular solar-powered QFs, in North Carolina. The issue arose as to whether utilities should have to pay QFs for capacity in years in which they do not have a capacity need. Witnesses in the proceeding described significant growth in solar production in the State resulting in over-supply, operational challenges, and artificially high costs passed on to North Carolina residents, businesses, and industries. Both DEP and DEC proposed, and a number of parties, including the Public Staff, agreed, that a utility should include zeros in the calculation of capacity rates for the years in which the utility does not have a capacity need.

While the case was pending, N.C. Gen. Stat. § 62-156(b)(3) was amended by the General Assembly to provide, with respect to power sales by small power producers to public utilities:

> A future capacity need shall only be avoided in a year where the utility's most recent biennial integrated resource plan filed with the Commission pursuant to G.S. 62- 110.1(c) has identified a projected capacity need to serve system load and the identified need can be met by the type of small power producer resource based upon its availability and reliability of power, other than swine or poultry waste for which a need is established consistent with G.S. 62-133.8(e) and (f).

In its Order in Sub 148, the Commission concluded that with regard to QFs that are small power producers, N.C.G.S. § 62-156(b)(3) requires that when calculating avoided capacity rates using the peaker method, it is appropriate to require a payment for capacity in years of a utility's IRP forecast period only when a capacity need is demonstrated during that period. Sub 148 Order, p. 48. The Commission found that providing a levelized capacity payment over the term of the standard offer contract is a reasonable means of implementing this capacity payment. The Commission also determined that this avoided capacity payment methodology is appropriate with regard to the standard offer to purchase available to QFs that are not small power producers. The Commission based this change in methodology upon the "changed economic and regulatory circumstances facing QFs and utilities" – namely, the increasing amount of solar powered QF development activity and its impact on utilities' systems and rates.

The underlying IRP for purposes of the Sub 148 proceeding – DEC's 2016 IRP – does not show a capacity need until 2023. As such, the Commission's ruling in Sub 148 results in avoided capacity rates that use a zero value for capacity for the years 2019 to 2022. However, that ruling does not apply to QFs that established a legally enforceable obligation (LEO) prior to the date the Company made its avoided cost filing in Sub 148. As a result, QFs establishing a LEO after November 15, 2016 (new QFs) receive a capacity value that is zero in years 2019 through 2022[1];

[1] New QFs under the standard offer tariff will receive capacity payments in years prior to the utilities' first capacity need because the new QFs will receive a levelized capacity rate reflecting a lower annual payment to account for those initial years in which there are no avoidable capacity costs. Sub 148 Order, pp. 40, 48.

QFs that established LEOs prior to November 15, 2016 (legacy QFs) receive a capacity value that is not zero in years 2019 through 2022.

Parties Discussion of the Issue

In this proceeding, the parties agree that the applicable Avoided Cost Proceeding for Rider 10 is Sub 148. The key issue in dispute between the Company and the Public Staff is whether because the Company does not show a capacity need until 2023, the Company is required by the Sub 1130 Agreement and the Sub 148 Order to use zero as the input when calculating its avoided capacity values for DSM/EE for years 2019 through 2022.

Public Staff witness Williams testified that the Public Staff interprets the Sub 1130 Order and the Sub 148 Order to mean that the Company's avoided capacity rates for DSM/EE should reflect zero avoided capacity value in years prior to the identified need for new capacity in the Company's IRP. He explained that as a result of the Commission ruling in the Sub 148 Order, "new" QFs seeking to sell their energy and capacity to DEC will not be paid capacity payments until new capacity is needed in 2023, as identified in the Company's 2016 IRP.

Witness Williams pointed out that the Commission noted in Sub 148 that "in addition to providing the basis for electric power purchases from QFs by a utility, the Commission determined avoided costs are utilized in, among other applications, the determination of the cost-effectiveness of DSM/EE programs and the calculation of the performance incentives for such programs..." He also asserted that witness Hinton's testimony in Sub 1130 explicitly linked the PURPA-based avoided capacity and energy costs to the savings and financial incentives of the Company's DSM/EE programs. As a result, he concluded that "in order to be consistent with the Sub 148 Order and the Revised Mechanism, "determinations of ongoing cost-effectiveness and utility incentives of both new DSM/EE programs and new vintages of existing DSM/EE programs starting in vintage 2019 should be based on avoided capacity rates that reflect zero avoided capacity value in years prior to the identified need for new capacity in the Company's IRP (2023)."

Witness Williams testified that the Public Staff believes that the Company was not consistent with Sub 148 and the Mechanism in how it applied avoided capacity value with respect to its DSM/EE programs.[1] He stated that, in assessing the ongoing cost-effectiveness of its DSM/EE programs and the appropriate level of utility incentives, the Company used avoided cost rates that reflected a "full capacity value," based on the peaker method, beginning in year one.

Witness Williams noted that in response to data requests, the Company contended DSM/EE is distinct from QFs in that without DSM/EE in the IRP, there would be a more immediate need for new capacity. As such, witness Williams stated, the Company's position is that the DSM/EE within the IRP has capacity value and should receive "full avoided capacity benefits" in all years. Witness Williams disagreed. First, he stated that in the context of the IRP, on a MW to MW basis, the contribution to peak provided by DSM/EE is functionally equivalent to the contribution to peak

[1] Witness Williams concluded that the avoided energy and T&D costs that DEC used to evaluate ongoing cost-effectiveness of its DSM/EE programs are reasonable and are based on the approved Sub 148 proceeding and the agreed methodology of the Mechanism, as revised in Sub 1130. The Company's calculation of avoided energy and avoided T&D were not disputed by any party.

provided by QF contracts. Therefore, he concluded that DSM/EE capacity is not distinct from QF capacity in this context and should not be treated differently.

In response to the Company's argument that DSM/EE value is derived from its usefulness in delaying new capacity need until 2023, witness Williams argued that only the DSM/EE actually needed to delay new capacity need would have any value.[1] According to witness Williams' calculations, from 2019 through 2022, only 40%, 49%, 63%, and 74% of the DSM/EE capacity is needed to maintain a 17% reserve margin. He stated that DSM programs alone can meet this need through 2021 and can meet 95% of the need in 2022. As such, he maintained that any new EE program or EE vintage would contribute effectively no capacity value and should, thus, be ineligible to receive capacity payments that are greater than zero.

Public Staff witness Maness testified that he concurs with witness Williams' recommendation that the avoided capacity cost benefits for purposes of the PPI and cost-effectiveness of the Company's DSM/EE programs be calculated under the assumption that capacity avoided prior to year 2023 be assigned a zero dollar value. Since the Company did not apply this method to calculate the estimated PPI for Vintage 2019, witness Maness recommended that the estimated Vintage 2019 PPI proposed by DEC in this case be adjusted to reflect this assumption. He testified that the Public Staff asked the Company to provide a calculation of estimated avoided cost benefits related to Vintage Year 2019 under the assumption that avoided capacity kW occurring prior to year 2023 is assigned a zero dollar value. According to the Company's calculation, making this assumption reduces the estimated Vintage 2019 system-level PPI from $25,050,064 to $16,055,813, a decrease of $8,994,251. Witness Maness incorporated this reduction into the billing factors set forth on Maness Exhibit 1. He also recommended that the $8,994,251 reduction in the system PPI be included in all future true-ups of the Vintage 2019 DSM/EE revenue requirement and billing factors.

Public Staff witness Williamson discussed the impact to the cost-effectiveness of the Company's DSM/EE portfolio that would result from applying zero capacity value for years prior to 2023, in accordance with the Public Staff's recommendation. Williamson Exhibit 2 shows the decrease in cost-effectiveness scores for each program when no capacity value is given for years that DEC's 2016 IRP does not show a capacity need. As mentioned above, in addition to the programs that were not cost-effective under the TRC test according to the Company's calculations, DEC's Non-Residential Smart $aver Custom/Assessments Program and EnergyWise for Business Program would no longer be cost-effective under the Public Staff's methodology.

In their rebuttal testimony, DEC witnesses Duff and Stevie explained that the Company strongly disagrees with the Public Staff's recommendation that the avoided capacity cost benefits for purposes of the PPI and cost-effectiveness of the Company's DSM/EE programs be calculated under the assumption that capacity avoided prior to year 2023 be assigned a zero dollar value.

[1] DEC witness Williams characterized the DSM/EE programs included in the DSM/EE IRP block as "fluid," because they are based on projections of participation and savings associated with approved programs, as well as the Company's market potential study. However, he acknowledged that the DSM programs in the DSM/EE IRP block are stable and expected to continue for the foreseeable future.

Witness Duff described the Sub 1130 Agreement and explained why the Company believes that the Agreement does not support the Public Staff's position. According to witness Duff, one of the primary purposes for the Sub 1130 revisions to the mechanism was to eliminate the previous "trigger" approach for updating avoided costs, so that avoided energy and capacity costs are updated essentially every two years instead of waiting for certain thresholds to be met. The second primary purpose of the agreement is that it changed the source and methodology for calculating avoided energy costs which previously had been based on the IRP, so that like avoided capacity costs, they would now be derived from the biennial avoided cost proceeding. He noted that the revisions to the mechanism approved by the Commission in Sub 1130 did not change the data source or methodology by which the Company was to calculate avoided capacity costs.

Witness Duff, described how, consistent with the revisions to DEC's DSM/EE cost recovery mechanism that the Commission approved in the Sub 1130 Order, the Company derived both the avoided energy and avoided capacity using the rates approved in the Company's most recent biennial avoided cost proceeding, which in this case is Sub 148. In particular, he noted that the Company utilized the avoided capacity value calculated using the Peaker Method consistent with the Company's understanding of the Sub 1130 Agreement, which, in the Company's view, did not modify the approach used in past DSM/EE proceedings.

He explained how the Company's application of avoided capacity values for its DSM/EE programs is also consistent with his testimony in last year's DSM/EE proceeding (which, he stated, witness Williams mischaracterized and took out of context), as well as that of Public Staff witness Hinton. In fact, the Company agrees with Public Staff witness Hinton's testimony that the rates paid QFs are generally linked to the avoided cost rates utilized for DSM/EE; however, that does not mean the rates are the same.

Witness Duff also testified about how the Company's application of values for avoided capacity for DSM/EE is also consistent with calculations the Company provided the Public Staff when the parties reached the Sub 1130 agreement, which showed what the change in Vintage 2019 PPI would be under the proposed revisions to the mechanism if the avoided costs rates pending before the Commission in E-100, Sub 148 were approved. This analysis clearly reflected avoided capacity values in the years 2019 through 2022, rather than the zero value advocated by witness Williams.

Witness Duff also disagreed with the Public Staff's argument that the Sub 148 Order dictates that the Company must use zero values instead of capacity values for existing DSM/EE programs. He explained how witness Williams quoted the Sub 148 Order out of context, and that the language witness William's referenced does not support the Public Staff's position. He also noted that witness Williams appears to imply that EE is the first capacity resource that should be cut out of the Company's resource plan, which would be inconsistent with the policy articulated by the North Carolina legislature in Senate Bill 3 to promote energy efficiency in this state.

Witness Stevie explained why DEC believes the Public Staff's approach is inappropriate and underestimates the value of the Company's DSM/EE programs. Witness Stevie testified that the Public Staff's adjustment would remove the avoided capacity value of DSM/EE in the years

2019 to 2022 for purposes of evaluating cost-effectiveness and PPI, a removal of capacity value for 1,119 MW of DSM impacts and 220 MW of EE impacts of summer capability from DEC's portfolio of DSM/EE programs.

In regard to DSM programs, DEC witness Stevie contended that the Public Staff had ignored the legacy aspect of DSM programs, which are not incremental programs. He stated that the Company's DSM programs had been established over a number of years and were a useful resource. He pointed to Public Staff witness William's testimony that by year 2022, 95% of the DSM programs' capacity would be needed to defer the need for new capacity in 2023. DEC witness Stevie contended that the legacy DSM programs should be treated similarly to QFs that had established legally enforceable obligations (LEOs) or had signed purchased power agreements (PPAs) prior to November 15, 2016. These QFs are entitled to capacity values for every year of their contracts. As the Commission or House Bill 589 did not retroactively end those capacity payments, Company witness Stevie argued that the Commission should not discontinue attributing capacity value to legacy DSM programs.

Further, DEC witness Stevie observed that, with respect to the Company's EE programs, the Company's MyHER program is effectively in the same position as the legacy DSM programs. The MW capability provided by the MyHER EE program was created in the past, prior to the establishment of the new avoided cost rates. All that is required is the expenditure of funds to maintain the impacts, just like the Company must do to maintain the availability of the impacts from the legacy DSM programs. Accordingly, he determined that the MyHER program impacts are also not incremental or new after November 2016; they are embedded in the resource plan, and like legacy QFs with LEOs existing prior to November 15, 2016, should receive a capacity value in the 2019 to 2022 timeframe.

Additionally, Company witness Stevie testified that it makes sense to recognize the capacity value of the Company's other EE programs during the 2019 to 2022 period in order to be consistent with the underlying resource plan and because it would not be realistic or advisable to suspend these programs until a capacity need arises.

In its Post-Hearing Brief, DEC stated that the Public Staff's interpretation of the issue is (1) contrary to the plain language and intent of the current Mechanism, (2) underestimates the value of DEC's DSM/EE programs, and (3) is contrary to the State's public policy.

In that brief, DEC explained that with regard to the parties' intent, the avoided capacity rate used for DSM/EE and the avoided capacity rate paid to a QF are not identical. DEC emphasized the language in the Sub 1032 Mechanism stating that the per kW avoided capacity costs reflected in avoided cost proceeding are "used to calculate avoided cost savings" for purposes of the PPI, and the revised paragraphs of the Mechanism stating that the program-specific per kW avoided capacity benefits shall be "derived from the underlying resource plan, production cost model, and cost inputs that generated the avoided capacity and avoided energy credits reflected in the most recent Commission-approved Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities." According to DEC, the avoided capacity cost reflected in the avoided cost proceeding has always been an input to the calculation of avoided capacity benefits for purposes of DSM/EE, but was never intended to be the same value. Further, DEC maintains that if the parties had intended for the avoided capacity rate the Company pays QFs to be equivalent to the avoided capacity rate calculated for DSM/EE, they would have said so in the plain language of the Mechanism. DEC discusses the details of the testimony of several witnesses that it contends support its plain language interpretation of Paragraph 69 of the Mechanism. With respect to DEC's argument regarding the effect on estimating the value of DEC's DSM/EE programs, the Company noted that the Public Staff's interpretation of Paragraph 69 ignores the legacy aspect of the Company's DSM programs. DEC maintains that the DSM programs included in its IRP are stable and are expected to continue for the foreseeable future. Therefore, these programs are treated as a dispatchable resource in the Company's IRP. According to DEC, it defies logic for a resource such as the legacy DSM programs not to receive a capacity valuation.

In addition, DEC contends that its MyHER EE program is effectively in the same position as its legacy DSM programs because the MyHER program impacts are embedded in the IRP, and, therefore, should receive a capacity value in the 2019 to 2022 time period. DEC acknowledges that its other EE programs, aside from MyHER, are in some respects different than the DSM programs in that most represent incremental new impacts in the IRP. However, DEC states that the Company's inputs to the IRP for the cost of the DSM and EE programs include not just the implementation cost, but also the estimate of the utility's PPI, which contains a capacity value for the years 2019 through 2022. As a result, to be consistent with the underlying IRP, including the cost inputs, DEC contends that the PPI should include the avoided capacity value of these EE programs as well for the years 2019 to 2022. Regarding public policy, DEC stated that DSM and EE programs are a desirable resource that is not only encouraged but mandated by the State, citing language from Senate Bill 3 that was incorporated into N.C. Gen. Stat. § 62-2(10). DEC notes that the stated goals of the legislation are to diversify the resources used to reliably meet the energy needs of consumers in the State, provide greater energy security through the use of indigenous energy resources available within the State, encourage private investment in renewable energy and EE, and provide improved air quality and other benefits to energy consumers and citizens of the State. In addition, DEC notes that Senate Bill 3 provides that the utilities shall be compensated for their DSM/EE efforts, and allows incentives to be awarded, including rewards based upon shared savings and avoided costs achieved by DSM/EE measures. N.C. Gen. Stat. § 62-133.9. DEC maintains that the Public Staff's interpretation of Paragraph 69 would eliminate a substantial portion of the incentive payments for those DSM/EE programs that help avoid capacity additions.

Finally, DEC argues that if the Commission had intended for DSM/EE to receive zero capacity payments, it would have said so in the Sub 148 Order. Yet, according to DEC, nowhere in the Commission's discussion of either the changed circumstances, mostly related to solar QFs, warranting the change in avoided cost methodology (Finding of Fact No. 1), or in its discussion of the adoption of the approach that new QFs should not receive payments for capacity in years in which there is no capacity need (Finding of Fact Nos. 5 and 6), does the Commission mention DSM/EE. See Sub 148 Order, pp. 9-19, 39-50. Further, DEC states that in concluding that QFs should only receive capacity payments in years in which the utility has a capacity need, the Commission noted that the operating characteristics of a QF must be considered in evaluating whether a QF resource can help to avoid the utility's planned capacity addition. In considering these characteristics and other factors, the Commission concluded that the capacity value provided by additional solar PV does not necessarily help the utilities offset or avoid their next capacity need. However, DEC contends that DSM/EE is different from solar QFs, and that none of the policy reasons behind the Commission's shift in avoided costs methodology articulated in the Sub 148 Order apply to DSM/EE. DEC states, for example, that there is no evidence in this proceeding that there is an over-supply of DSM/EE programs that customers are paying artificially high prices for DSM/EE, or that DSM/EE is burdening the system. Finally, DEC submits that there is a fundamental difference between DEC's customers paying for capacity in the form of additional QF generation that the Company does not need, compared to the Company's implementation of DSM/EE programs to encourage customers to use less energy and capacity in accordance with State policy, as expressed in Senate Bill 3 and elsewhere in the Public Utilities Act.

In its Post-Hearing Brief, NCSEA states that eliminating proper compensation for avoided capacity costs could have a dire effect on the cost effectiveness of DSM/EE programs, and could discourage DEC from maintaining or increasing its deployment of DSM/EE resources. NCSEA cites the testimony of Public Staff witness Williams that the removal of avoided capacity costs when measuring the cost effectiveness of programs whose useful lives do not extend to periods when DEC's IRP shows a capacity need would cause certain programs, including the Non-Residential Smart $aver Custom Assessments program, not to be cost effective for vintage 2019. NCSEA submits that the Commission should reject the Public Staff's position that the avoided capacity benefits used for program approval, PPI, and review of on-going cost effectiveness of DEC's DSM/EE programs should include zero capacity value in years prior to 2023.

In their Post-Hearing Brief, NC Justice, SACE and NRDC agree with DEC's calculation of avoided capacity costs for purposes of establishing the PPI and calculating cost effectiveness. They further contend that assigning a zero-capacity value to DEC's suite of cost-effective DSM/EE programs that carry on from year to year would discourage the Company from making investments that save ratepayers money in part because of the avoided capacity.

Commission Discussion

Based on the foregoing and the plain language of Paragraph 69 of the Mechanism, the Commission concludes that the appropriate avoided capacity benefits and per kWh avoided energy benefits to be used for the initial estimate of the PPI and any PPI true-up should be derived from DEC's IRP, production cost model, and cost inputs that generated the avoided capacity and avoided energy credits approved in the Sub 148 Order. In particular, the Commission is persuaded that if DEC and the Public Staff had achieved a meeting of the minds on simply using the avoided costs adopted in the Sub 148 Order and subsequent avoided cost proceedings, then they would have simply stated that in Paragraph 69. They did not do so. Furthermore, based on the record in this proceeding, as well as the record in Sub 1130, the Commission finds and concludes that the Company's calculation of Rider 10 is consistent with the language and intent of the Sub 1130 Agreement. As DEC witness Duff testified, the Sub 1130 Agreement was intended to eliminate the trigger method, so that avoided costs would be updated more frequently, and to change the source of avoided energy costs, so that avoided energy and avoided capacity rates for DSM/EE would be derived from the same proceeding. The revisions to Paragraphs 19, 23, and 69 resulting from the Sub 1130 Agreement did not alter the source or manner in which the avoided capacity costs are to be derived for the purpose of calculating cost-effectiveness and incentives associated with DSM/EE programs. The Commission generally agrees with the testimony of DEC's witnesses and DEC's arguments that evaluating the contributions that DSM/EE measures make to a utility avoiding future capacity needs to determine cost-effectiveness is inherently different than the evaluation undertaken to determine the capacity costs avoided through the purchase of the electric output from a QF[1]. In addition, the Commission is persuaded by the arguments of DEC, NCSEA and NC Justice Center that assigning a zero capacity value to DSM programs would under-value the contributions of those programs and send the wrong pricing signal. The Commission, therefore, declines to accept the Public Staff's downward adjustment to the Vintage 2019 PPI, and, instead, accepts the cost-effectiveness calculations performed by the Company for purposes of Rider 10, and approves the Company's calculation of the DSM/EE rates for Vintage 2019, as reflected in the rebuttal testimony and exhibits of DEC witness Miller.

The Commission further finds and concludes that the components of Rider 10, as shown in the testimony and exhibits of Company witnesses Miller and Evans, are appropriately in compliance with the Commission's findings and conclusions herein, as well as the Commission's findings and conclusions as set forth in the Sub 831 Found Revenues Order, the Sub 938 First Waiver Order, the Sub 938 Second Waiver Order, the Sub 979 Order, the Sub 1032 Order, and the Sub 1130 Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 32-33

The evidence in support of these findings and conclusions can be found in the testimony of DEC witness Evans, Public Staff witness Williamson, and NC Justice Center witness Neme.

Company witness Evans noted that Vintage 2017 of the Company's DSM and EE programs produced over 907 million kWh of energy savings and over 1,022 megawatts MW of capacity savings, which produced net present value avoided cost savings of over $586 million. During Vintage 2017, DEC's portfolio of DSM/EE programs was able to deliver energy and capacity savings that yielded avoided costs that were 162% of its target, while expending only 147% of targeted program costs.

Witness Evans testified that opt-outs by qualifying industrial and commercial customers have had a negative effect on the Company's overall non-residential impacts. For Vintage 2017, 4,075 eligible customer accounts opted out of participating in DEC's non-residential portfolio of EE programs, and 4,863 eligible customer accounts opted out of participating in the Company's non-residential DSM programs. While only 78 eligible customers that were opted out of the

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[1] However, the Commission is not prepared to agree wholly with those arguments, because in the Sub 148 Order the Commission distinguished between "small power producers" colloquially referred to as "renewable QFs," and those QFs that are not "small power producers," such as combined heat and power QFs. See N.C.G.S. 62-3(27a); Sub 148 Order at 18. With regard to small power producers, and the subset of QFs who DEC refers to as Solar QFs, the changes in capacity payments that the Commission approved in the Sub 148 Order were required pursuant to amended N.C.G.S. 62-156(b)(3). Sub 148 Order at 48. Much of the discussion cited by DEC in its proposed order was related to evidence that supported the Commission's findings and conclusions that the same changes would be appropriate with regard to the standard offer to purchase that is available to QFs that are not small power producers. Id.

Vintage 2015 EE Rider opted in to the Vintage 2016 DSM Rider, 199 eligible customers that were previously opted out chose to opt in to the Vintage 2017 EE Rider.

Witness Evans stated that to reduce opt-outs, the Company continues to evaluate and revise its non-residential portfolio of programs to accommodate new technologies, eliminate product gaps, remove barriers to participation, and make its programs more attractive to opt-out eligible customers. It also continues to leverage its Large Account Management Team to make sure customers are informed about product offerings and their ability to opt into the Company's DSM and/or EE offerings during the March opt-in window.

NC Justice Center witness Neme testified that DEC delivered its highest DSM/EE portfolio savings in 2017, 1.07% of prior year sales. In regard to the proposed 2019 portfolio, he noted with approval the forecast of new annual savings of about 0.95% of total forecast sales, and 1.38% of sales to non-opt-out customers, as well as the projected portfolio cost-effectiveness of 2.46%.

Witness Neme also pointed out the wide array of efficiency measures and programs, as wells as some state-of-the-art program design features. However, he noted his concern that DEC was achieving 70% of its residential savings and 40% of its total portfolio savings from MyHER, which has short-lived savings. Witness Neme testified that DEC was inadequately promoting programs with longer-lived major measures such as the Residential Smart $aver EE program that comprehensively treat buildings. He also pointed out that as DEC's calculations assume that the annual savings produced by a residential LED light bulb installed as a result of its EE programs will be realized in each of the next 12 years at the same level experienced in the first year despite the new federal efficiency standards imposed by the Energy Independence and Security Act for most residential light bulbs. Witness Neme also contended that DEC needed to increase its investment in lower-income communities and programs that reached rental units. In particular, he recommended that DEC:

> (1) endeavor to improve participation in its Residential Smart $aver program significantly through establishment of a midstream channel for promoting some of the measures through equipment distributors (and possibly retailers and/or other parts of the supply chain), increasing incentives, enhancing marketing, and/or other means to reach more customers.
>
> (2) consider greater promotion of whole-building retrofits, including support for both (A) improvements to building envelopes (e.g. insulation and air leakage reduction); and (B) retrofitting single-family and multi-family buildings that currently have electric-resistance heating with high-efficiency heat pumps.
>
> (3) build on recent success and progress-in promoting efficiency measures for business customers through the midstream channel of its non-residential Smart $aver prescriptive rebate program.
>
> (4) assess the potential to reduce the number of customers who opt out of its programs by improving business customers' understanding of its programs and/or

improving the designs of its programs to make them more attractive to such customers.

Witness Neme recommended that these issues be referred to the collaborative for discussion, and that DEC report back on them in its 2019 rider filing. He also suggested that it would be less burdensome to conduct EM&V if DEC or the State as whole used a TRM, and discussed a number of factors that allow collaboration, such as the EE Collaborative conducted by DEC, to function well.

Public Staff witness Williamson also discussed his concerns regarding the fact that the EE lighting market is being transformed and that non-specialty LED lighting will likely become the baseline standard for general service bulb technologies by January 2020, thereby decreasing savings from EE lighting programs. He indicated that it appears that the lighting market may be close to adopting EE lighting technologies as a baseline and that further incentives for certain EE lighting measures for certain customers may not be necessary after January 1, 2020. Witness Williamson recommended that the Company include in its 2019 rider filing its plans to incorporate the impacts identified in its lighting shelving study, including any baseline changes for non-specialty LED bulb lighting technology in its EE programs.

Witness Williamson also testified that the Company was in the process of installing Advanced Metering Infrastructure (AMI) meters and new customer information systems, and there may be some redundancy in the information available through these new systems and the information provided through the MyHER program. He stated that the EM&V for the MyHER program will need to clearly isolate any savings associated with enhanced access to customer data provided through AMI and customer information systems from the Impacts solely attributable to the customized suggestions for the home provided by the MyHER program.

In his rebuttal testimony, DEC witness Evans did not disagree with considering the items recommended by NC Justice Center witness Neme to be discussed in the DEC Collaborative, but suggested that a combined DEC and Duke Energy Progress, LLC (DEP) collaborative would be more efficient given the commonality between DEC's and DEP's programs. Witness Evans suggested that a combined collaborative meet every two months rather than quarterly and that working groups be employed when deemed beneficial by the Collaborative. He did not object to initiating a working group to review the use of a TRM, but noted that the working group should include, at a minimum, representation by the Public Staff, Electric Membership Cooperatives, impacted municipalities, and investor owned-utilities, as well as South Carolina utilities.

In its Post-Hearing Brief, NC Justice Center stated that it generally supports DEC'sapplication, and applauds DEC for the energy savings achieved by the Company's portfolio of DSM/EE programs. Nonetheless, NC Justice Center stated that it continues to have concerns about the Company's: (1) over reliance on short-lived measures, particularly its residential behavioral program; (2) inadequate promotion of longer-lived measures and comprehensive treatment of buildings; (3) insufficient planning to offset a significant loss of lighting savings once the 2020 federal EISA efficiency standards go into effect; and (4) need to reach more lower-income communities and deliver programs that reach rental units. NC Justice Center reiterated the testimony of its witness, Neme, on each of these points. In addition, NC Justice Center discussed Neme's recommendations for overall improvements to DEC's programs, and changes to more accurately calculate savings from the Company's major residential behavioral and lighting programs. NC Justice Center stated that the Commission should order DEC to take up these issues in the Collaborative over the course of the next year.

Further, NC Justice Center stated that in order for the Collaborative to make progress on these substantive issues the Commission should adopt the recommendations put forward by witness Neme to make the Collaborative function more effectively. Moreover, NC Justice Center stated that it agrees with the Company's plan to continue offering the Residential Energy $aver program, even though DEC is still working on making the program cost effective.

NCSEA, in its Post-Hearing Brief, supported the recommendations made by NC Justice Center. In summary, NCSEA stated that a TRM could be used to streamline the regulatory process for DEC's DSM/EE programs by, among other things, providing baseline energy usage, data for use in calculating energy savings, algorithms for calculating energy savings, and a process for updating deemed savings for existing measures, as well as determining deemed savings for new measures. Further, NCSEA submitted that a TRM would create greater certainty as to the savings to be produced by DEC's DSM/EE measures, thereby reducing regulatory risk and regulatory costs.

In addition, NCSEA noted that DEC is currently deploying AMI meters throughout its territory, and that the data provided by AMI meters can be utilized to reduce energy consumption. NCSEA agreed with Public Staff witness Williams' suggestion that the incremental data collected by AMI meters should be leveraged to improve the MyHER program and integrate these two technologies in a way that reduces the "redundancy in the information available through these new systems and the information provided through the MyHER program[.]"

Moreover, NCSEA supported witness Neme's suggestions for modifying DEC's portfolio of programs, and shared witness Neme's concern that DEC places too much relative emphasis on programs that deliver only short-lived savings. Further, NCSEA stated that DEC should continue its investigation, as discussed at past Collaborative meetings, into on-bill financing programs to support retrofits and provide greater access to efficiency for low-income customers.

NCSEA also agreed with witness Neme's suggestions for improving DEC's Collaborative, and agreed that examples from other states' collaboratives should be discussed at future Collaborative meetings. In addition, NCSEA stated that full participation in the Collaborative by experts in energy efficiency and regulatory policy may be hampered by the exclusion of attorneys from the meetings, and it requested that the Commission direct the Collaborative to discuss whether to remove this informal restriction and allow attorneys to attend Collaborative meetings.

Finally, NCSEA disagreed with Public Staff witness Williamson's suggestion that DEC's HVAC EE program should be suspended. It contended that suspension of the program would eliminate important financial incentives for increasing the efficiency of the largest component of energy use in a residence, and eliminate a primary source of long-term residential energy efficiency opportunities. Further, NCSEA contended that suspending the program would create a severe market disruption for both customers and HVAC contractors, and would unfairly eliminate this long-term energy efficiency opportunity for DEC residential customers who need to replace qualifying HVAC equipment in the upcoming program year. NCSEA submitted that by working closely with stakeholders, trade allies, and investigating lessons learned from other states and utilities, DEC can again make this critical program cost effective. Instead of program suspension, NCSEA supported the Public Staff's suggestion that DEC show faith in the program by "agreeing to pick up a portion of the program costs and the net loss revenues to the extent the program is not cost-effective."

The Commission is of the opinion that the Collaborative is the appropriate forum for consideration of the recommendations made and concerns expressed by witness Neme regarding improving participation in the Residential Smart $aver program, promoting whole-building retrofits, building on recent success and progress in promoting efficiency measures for business customers through the midstream channel of its non-residential Smart $aver prescriptive rebate program, assessing the potential to reduce the number of customers who opt out of DEC's non-residential programs, considering implementation of a TRM, improving the effectiveness of the Collaborative, the amount and persistence of the savings from the MyHER program, and the impact on DEC's DSM/EE portfolio of upcoming changes in lighting standards. The Collaborative should also consider the issues raised by Public Staff witness Williamson regarding the MyHER program and the impact of upcoming lighting standards. Further, the Commission does not object to DEC's combining its collaborative with that of DEP and meeting on a more frequent basis. Finally, the Commission agrees that if the Collaborative determines that a TRM working group should be established, electric power suppliers and other stakeholders from both North Carolina and South Carolina should be invited to participate. DEC should report on the outcome of all these matters referred to the Collaborative in its 2019 rider filing.

IT IS, THEREFORE, ORDERED as follows:

1. That the Commission hereby approves the billing factors as set forth in Miller Rebuttal Exhibit 1, to go into effect for the rate period January 1, 2019, through December 31, 2019, subject to appropriate true-ups in future cost recovery proceedings consistent with the Sub 1032 and Sub 1130 Orders, and other relevant orders of the Commission.

2. That DEC shall work with the Public Staff to prepare a proposed Notice to Customers of the rate changes approved herein. Within 30 days from the date of this Order, the Company shall file said notice and the proposed time for service of such notice for Commission approval.

3. That the Company shall propose modifications to the Residential Smart $aver EE Program no later than October 31, 2018, with the goal of restoring the TRC score to 1.0 or greater, and the Company shall include a discussion of impact of these modifications and any other actions it has taken to improve cost-effectiveness in next year's DSM/EE rider proceeding.

4. That in its next rider application, DEC shall address the continuing cost-effectiveness of the Non-Residential Smart $aver Performance Incentive Program and if it is not cost-effective, provide details of plans to modify or close the program.

5. That the EM&V report for the Non-Residential Smart $aver Custom program (Evans Exhibit B) shall be revised as discussed by Public Staff witness Williamson and refiled in the next rider.

6. That the results of the EM&V report for the My Home Energy Report program (Evans Exhibit C) are accepted conditionally for purposes of this proceeding. The Public Staff may continue to review this report and offer further recommendations for the Company's consideration in the next DSM/EE rider proceeding.

7. That DEC shall leverage its Collaborative to discuss the EM&V issues and program design issues raised in the testimony of NC Justice Center witness Neme as discussed herein. The results of these discussions shall be reported to the Commission in the Company's 2019 DSM/EE rider filing.

8. That beginning in 2019, the combined DEC/DEP Collaborative shall meet every other month.

ISSUED BY ORDER OF THE COMMISSION.
This the 11th day of September, 2018.

NORTH CAROLINA UTILITIES COMMISSION
M. Lynn Jarvis, Chief Clerk

ONE-HUNDRED EIGHTH REPORT

OF THE

NORTH CAROLINA

UTILITIES COMMISSION

ORDERS AND DECISIONS

Volume II

ISSUED FROM
JANUARY 1, 2018 THROUGH DECEMBER 31, 2018

ONE-HUNDRED EIGHTH REPORT
of the
NORTH CAROLINA UTILITIES COMMISSION

ORDERS AND DECISIONS

Issued from

January 1, 2018, through December 31, 2018

Edward S. Finley, Jr., Chairman

*Bryan E. Beatty, Commissioner

ToNola D. Brown-Bland, Commissioner

Jerry C. Dockham, Commissioner

James G. Patterson, Commissioner

Lyons Gray, Commissioner

Daniel G. Clodfelter, Commissioner

*Charlotte A. Mitchell, Commissioner

North Carolina Utilities Commission
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The Statistical and Analytical Report of the North Carolina Utilities Commission is printed separately from the volume of Orders and Decisions and will be available from the Office of the Chief Clerk of the North Carolina Utilities Commission upon order.

*Charlotte A. Mitchell was sworn in on January 26, 2018, replacing Bryan E. Beatty.

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Motion of Duke Energy Corporation, Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, and Piedmont Natural Gas Company, Inc. to Amend Regulatory Conditions	)))))	ORDER GRANTING MOTION TO AMEND REGULATORY CONDITIONS

BY THE COMMISSION: On March 2, 2018, Duke Energy Corporation (Duke Energy), Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP) and Piedmont Natural Gas Company (Piedmont) (collectively the Companies and Applicants) filed a Motion to Amend Regulatory Conditions, the most recently adopted in the Matter of Application for Duke Energy Corporation and Piedmont Natural Gas Company, Inc. to Engage in a Business Combination Transaction and Address Regulatory Conditions and Code of Conduct in Docket Nos. E-2, Sub 1095, E-7, Sub 1100, and G-9, Sub 682. In the motion, the Companies provide the following Company backgrounds:

Duke Energy is a corporation organized and existing under the laws of Delaware and is headquartered in Charlotte, North Carolina. DEC, DEP, and Piedmont are wholly-owned subsidiaries of Duke Energy.

DEC is in the business of generating, transmitting, distributing and selling electricity to approximately 2.5 million retail customers in a service area located in portions of central and western North Carolina and western South Carolina. DEC also sells electricity in the wholesale market to various municipal, cooperative and investor-owned electric utilities.

DEP is in the business of generating, transmitting, distributing and selling electricity to approximately 1.5 million retail customers in a service area located in portions of eastern, central, and western North Carolina and eastern South Carolina. DEP also sells electricity in the wholesale market to various municipal, cooperative and investor-owned electric utilities.

Piedmont is a natural gas utility authorized to distribute natural gas services to customers in its service territory in North Carolina, South Carolina, and Tennessee. Piedmont provides natural gas services to approximately 1 million customers in the three states in which it provides distribution services.

DEC, DEP, and Piedmont are all public utilities pursuant to Chapter 62 of the North Carolina General Statutes and are subject to the Commission's jurisdiction.

Comments of the Companies

In the motion, the Companies provide a summary of events prompting the filing of the motion. The Companies indicate that as a result the Commission's approval of past mergers involving Duke Energy, including its 2006 merger with Cinergy Corp. (Cinergy Merger), its 2012 merger with Progress Energy, Inc. (Duke/Progress Merger) and, recently, its 2016 merger with Piedmont (Piedmont Merger), Duke Energy, DEC, DEP, and Piedmont are subject to more than 95 Regulatory Conditions, relating to almost every aspect of their operations in North Carolina and beyond. Specific to this motion, Sections II and III of the Regulatory Conditions include Regulatory Conditions that were intended "to protect the jurisdiction of the Commission against the risk of federal preemption .... " Order Approving Merger Subject to Regulatory Conditions and Code of Conduct, Docket Nos. E-2, Sub 1095, E-7, Sub 1100, and G-9, Sub 682 at Appendix A, p. 5. The Companies posit that these Regulatory Conditions include the Companies and their affiliates waiving certain federal rights and numerous requirements and "gatekeeping" procedures imposed upon DEC, DEP and Piedmont, before they may enter into or file an affiliate agreement at the NCUC, enter into certain wholesale agreements, or file affiliate agreements or other matters at the Federal Energy Regulatory Commission (FERC) subject to the FERC's jurisdiction under the Federal Power Act.

The Companies identify two recent decisions, one by the D.C. Circuit Court of Appeals and the other by the FERC, that have raised questions on the validity of some of the Regulatory Conditions pertaining to assertion of the NCUC's jurisdiction over certain wholesale and affiliate agreements and other filings made at the FERC. The Companies state that the subject matters of the decisions are different, but the legal issues addressed are similar. In the D.C. Circuit, the City of Orangeburg, South Carolina (Orangeburg) challenged the FERC's approval of the Joint Dispatch Agreement (JDA) as part of the Duke/Progress merger. Orangeburg v. FERC, 862 F.3d 1071 (D.C. Cir. 2017) (Orangeburg). The D.C. Circuit vacated the FERC's approval of the JDA and remanded the case to the FERC. Following that decision, the FERC rejected DEC's and DEP's petition for approval of an affiliate As-Available Capacity Sales Agreement. Order Rejecting As-Available Capacity Sales Agreement, 161 FERC ¶ 61,029, October 10, 2017.

The Companies explain that both the D.C. Circuit and the FERC expressed concerns that the Regulatory Conditions infringed upon federal jurisdiction, and the D.C. Circuit and the FERC signaled that FERC may preempt those Regulatory Conditions currently in effect. Furthermore, the Companies are concerned that the Order Rejecting As-Available Capacity Sales Agreement indicates that the D.C. Circuit's opinion in Orangeburg has given the FERC a greater sense of urgency in addressing the issues pertaining to certain Regulatory Conditions raised by Orangeburg. Therefore, the Companies opine the FERC will reject their filings due to their required references to, or inclusion of, these Regulatory Conditions. The Companies believe that requesting the NCUC, which has more familiarity and expertise with these Regulatory Conditions, to address this issue at this time is preferable to risking more pervasive preemptive action of NCUC authority by the FERC. For these reasons, the Companies submit for approval the attached proposed revisions to the Regulatory Conditions pertaining to federal preemption. The Companies are not at this time proposing changes to the majority of the Regulatory Conditions. The Companies state that the proposed revisions strike a balance between preserving the NCUC's jurisdiction as intended by

Sections II and III of the Regulatory Conditions and mitigating the risk of pervasive preemptive action by the FERC.

1. The Orangeburg Decision

The Companies indicate that this case arose following Orangeburg's challenge to the FERC's approval of the Duke/Progress merger. The dispute itself dates back to 2008, when Orangeburg contracted with DEC to provide wholesale power to the city for 10 years. Under the agreement, DEC would have treated Orangeburg as a native load customer, which would allow Orangeburg to purchase power at lower system average costs instead of higher incremental costs. The agreement, however, required consideration of certain Regulatory Conditions imposed on DEC as a result of the Cinergy merger. Under these Regulatory Conditions, DEC was required to provide their lowest cost power to its retail native load customers in North Carolina and plan their respective systems with that goal. In addition, DEC was required to provide the NCUC with notice if the utility intended to treat any new wholesale customer as a native load customer, and the NCUC reserved the right to decide for itself whether to recognize native-load status when it came to its own retail ratemaking, accounting, and reporting. After DEC provided the NCUC 30-days advance notice of its agreement with Orangeburg, the Commission issued a declaratory ruling stating that it would set DEC's retail rates as if DEC received the incremental costs of its power in its sales to Orangeburg. Order on Advance Notice and Joint Petition for Declaratory Ruling, Docket No. E-7, Sub 858, March 30, 2009. In 2009, Orangeburg filed an Application and Petition for Declaratory Order and Request for Expedition And Summary Disposition of the City of Orangeburg, Docket No. EL09-63-000 (July 2, 2009), with the FERC challenging the NCUC's ruling and its "gatekeeping" provisions, which the FERC rejected in 2015 as moot because the agreement between DEC and Orangeburg was terminated. Order Dismissing Petition/or Declaratory Order, 151 FERC ¶ 61,241 (June 18, 2015).

The Companies assert that as part of FERC's review of the subsequent Duke-Progress merger, the FERC reviewed the JDA. Orangeburg intervened in the FERC proceeding, arguing that section 3.2 of the JDA "effectively incorporated the NCUC regulatory regime" and resulted in usurpation of the FERC's exclusive jurisdiction over wholesale power rates. Orangeburg, 862 F.3d at 1076. Additionally, Orangeburg argued that the JDA contained Regulatory Conditions that allowed Duke Energy, Progress Energy, and the NCUC to unduly discriminate against wholesale customers by arbitrarily dividing wholesale sales into native load and non-native load. The FERC rejected both arguments by Orangeburg, relying on FERC Order No. 2000, affirming a state's authority to accord preferential treatment to native load customers. Orangeburg appealed to the D.C. Circuit, which vacated the FERC's decision and remanded the case back to the FERC. Orangeburg, 862 F.3d 1071.

In pertinent part, the Court determined Orangeburg suffered an injury-in-fact caused by the FERC approval of the JDA, which is redressable by the Court. The Companies highlight that one important note is the D.C. Circuit's criticism of FERC's "acquiescence" to the NCUC. The Court stated that the FERC was offering a view on NCUC's authority: contrary to Orangeburg's protest, the FERC concluded that the provisions incorporating the state regulatory regime "pertain[ed] fundamentally to retail ratemaking." Id. at 1081. Furthermore, the Court stated, "FERC's approach to the JDA fits within a pattern of acquiescence." Id. The D.C. Circuit noted that shortly after the

2008 Duke Orangeburg deal was frustrated by the 2009 NCUC Declaratory Ruling, Orangeburg had filed a petition with the FERC requesting that the Commission find that NCUC's ruling was preempted by federal law. Id.

According to the Companies, in vacating the FERC's ruling, the Court focused on the obligations of the FERC to avoid disparate rate treatment. "We accept disparate treatment between ratepayers only if FERC offers a valid reason for the disparity. Unless the FERC offers such a valid reason, its decision to approve disparate treatment of wholesale ratepayers is arbitrary and capricious." Id. at 1084. The Court determined Orangeburg suffers disparate rate treatment under the JDA, and stated in regards to the FERC's Order, "On its face, the Order does not supply a reason for the JDA's disparate treatment of native-load and non-native-load interstate wholesale customers, especially in light of NCUC's alleged control over which customers enjoy native-load status." Id. at 1085.

The Companies further explain that the Court determined Order No. 2000, on which the FERC based its entire decision, was insufficient authority as Order No. 2000 dealt with regional transmission authorities and the power of the states to require retail sales of its lowest cost power to state customers. Orangeburg's petition, however, concerned wholesale rates.

> The cited passage from Order No. 2000 appears to stand for the proposition that, for example, the NCUC may require Duke to sell its lowest cost power to retail native-load customers in North Carolina. But that proposition is uncontested: Orangeburg protests the NCUC's control over wholesale native-load customers, not the state commission's imposition of requirements for retail native-load customers.

Id. at 1086. Additionally, the Court stated that Order No. 2000, as interpreted by the FERC, appears to be in conflict with Order No. 888, which bars regulatory obligations requiring utilities to treat certain wholesale customers as native load, because the Commission's interpretation of Order No. 2000 authorizes the NCUC to require DEC to serve the "lowest cost power" to native-load wholesale customers. Finally, the Companies state that the Court determined that the FERC's interpretation of Order No. 2000 suggests the NCUC has the authority to regulate interstate wholesale power sales which plainly intrudes on FERC authority. The D.C. Circuit concluded that, "insofar as the Commission attempts to justify disparate treatment of interstate wholesale customers by invoking a state commission's authority, the FERC's interpretation of Order No. 2000 is unsound." Id. at 1087.

2. Order Rejecting As-Available Capacity Sales Agreement

The Companies state that on May 17, 2017, after an extended advance notice review period at the NCUC, DEC and DEP filed an As-Available Capacity Sales Agreement (the Agreement) with the FERC for approval. This affiliate Agreement permitted the sale of excess short-term capacity between DEC and DEP. According to the Companies, without approval of the Agreement, DEP and DEC would be forced to procure short-term energy at higher prices or commit generation resources that would otherwise be left offline. Therefore, the Companies contend that this Agreement benefitted customers through the purchase of short-term capacity between DEC and DEP at lesser cost than if they went to procure capacity in the marketplace. As part of the terms and conditions of the Agreement, DEC and DEP included the required provisions of Regulatory Condition 3.1(b).

Upon review, the Companies note that the FERC recognized the benefits of the Agreement but denied approval. In its determination the FERC wrote, "While we recognize the benefits that can be achieved by the (Agreement), the applicants have not met their burden of demonstrating the capacity agreement is just and reasonable and not unduly discriminatory or preferential." The decision continued, "Article XI of the (Agreement) includes provisions that pertain fundamentally to retail ratemaking. We find the inclusion of such provisions not appropriate in a Commission-jurisdictional wholesale agreement." Order Rejecting As-Available Capacity Sales Agreement, 161 FERC 61,029 at P. 12 (2017). The FERC denied approval without prejudice, allowing DEP and DEC to refile in the future to address the concerns of the FERC. The Companies contend that the FERC did not indicate it had any concerns with the Agreement other than the inclusion of these provisions.

The Companies posit that currently two different legal authorities have expressed serious concerns with certain Regulatory Conditions as infringing on federal jurisdiction. The Companies outline that the D.C. Circuit ruled FERC's reasoning for the approval of the JDA to be arbitrary and capricious, in part due to the inclusion of provisions required by the Regulatory Conditions. The Companies contend that the D.C. Circuit appears highly skeptical of the NCUC's required inclusion of provisions under certain Regulatory Conditions. Additionally, the Companies point out that the FERC expressed similar skepticism concerning the legality of these Regulatory Conditions. While the FERC did not preempt these Regulatory Conditions outright, the issue of preemption was not before the FERC at that time. According to the Companies, the timing of both decisions suggests that the FERC may have been reacting to the D.C. Circuit in issuing its Order denying approval of the Capacity Sales Agreement. The Companies highlight that both decisions included references to the Regulatory Conditions creating disparate or discriminatory treatment without reasonable justification.

3. The D.C. Circuit's Decision and the FERC Decision Warrant a Review and Modification of Certain Regulatory Conditions

The Companies conclude that these Regulatory Conditions as they now exist are unlikely to survive continued FERC review. The Companies believe that requesting the NCUC to address these potentially concerning Regulatory Conditions that it has reviewed and approved in previous merger dockets is preferable and more advantageous to the Companies' ratepayers than risking more pervasive preemption of NCUC authority by the FERC. The Companies contend that the FERC's rejection of the As-Available Capacity Sales Agreement due to the inclusion of the provisions required by the Regulatory Conditions already has deprived ratepayers of benefits that they would have received under the Agreement. The Companies have identified those Regulatory Conditions that appear to be the most ripe for preemption by the FERC; however, to minimize potential changes to the Regulatory Conditions, the Companies have limited their proposed amendments to the Regulatory Conditions that are most impacted by the two decisions.

ELECTRIC – MISCELLANEOUS

The Companies propose the following amendments to the Regulatory Conditions:

1. Regulatory Condition 2.1 - Waiver of Certain Federal Rights – The Companies argue that given the recent FERC Order and the D.C. Circuit's Orangeburg decision, it is questionable whether the Commission can require the Companies to waive a right that is given by Federal Law if waiving that right limits federal jurisdiction.

2. Regulatory Condition 3.1(a) - Advance Notice of Affiliate Contracts to be Filed with the FERC – The Companies note that this provision is at the core of the gatekeeping criticism voiced by the D.C. Circuit. The Companies argue that the last sentence of this provision seems particularly troublesome. It enables the Commission to serve as gatekeeper to the FERC by enacting provision 3.1(c) and sets up a specific procedure to deal with filings that are subject to FERC jurisdiction.

3. Regulatory Condition 3.1(b)(i)-(iv) - Required Provisions in Affiliate Contracts –The Companies state that these provisions require the Companies to include specific language in affiliate contracts. This language was included in both the JDA and in the Order Rejecting As-Available Capacity Sales Agreement. The Companies state that Regulatory Condition 3.1(b)(i) has been subject to waivers by the NCUC because it effectively creates an illusory contract. <u>See e.g.</u> Order Accepting Affiliate Agreement and Allowing Limited Waiver of Regulatory Condition, Docket Nos. E-2, Sub 1118 and E-7, Sub 1120 (Nov. 21, 2016); see also, <u>Bowman v. Hill</u>, 45 N.C. App. 116, 117,262 S.E.2d 376, 377 (N.C. Ct. App. 1979) ("An apparent promise, according to its terms, makes performance optional with the promiser no matter what may happen, ... is in fact no promise. Such an expression is often called an illusory promise."). Additionally, note the Companies, these provisions were removed from the JDA upon the request of the FERC. The Companies state the FERC did not opine on the Commission's authority to impose such requirements, but the focus on the FERC occasioned by the D.C. Circuit's decision may change FERC's review.

4. Regulatory Condition 3.1(c)(i)-(ii) - Authority over Affiliate Contracts Required or Intended to Be Filed with the FERC – The Companies state that these provisions are fundamental to the accusations that the Commission is inappropriately serving as gatekeeper to the FERC. The Companies reiterate that the D.C. Circuit and the FERC have indicated that they are reluctant to allow the Commission to have first approval over matters involving federal jurisdiction.

5. Regulatory Condition 3.1(d) & (e) – According to the Companies, similar to the previous provisions, these sections give the Commission authority over federal jurisdiction and may be preempted by the FERC and the D.C. Circuit. The Companies argue that sub-section (e) is almost a reverse preemption of the State over the FERC.

6. Regulatory Condition 3.3(c)(ii) – The Companies state that this provision effectively allows the Commission to invalidate federal law. The Companies argue that it infringes on federal jurisdiction and appears to reverse the Supremacy Clause of the Constitution. The Companies state that if an issue arises as to transfer value that is a matter of federal law, it would appear that any concerns should be addressed by a petition to the FERC.

7. Regulatory Condition 3.3(d) – The Companies offer that this provision effectively allows the Commission to control the contents of Applications filed with the FERC.

8. Regulatory Condition 3.7 (b)-(d) - Wholesale Power Contracts Granting Native Load Priority – The Companies contend that this provision requires 30-day advance notice to the Commission of DEC's or DEP's intention to grant Native Load Priority to a wholesale customer (other than those historically served, as listed in Regulatory Conditions 3.7 (b)-(c)). Again, the Companies opine that this restricts priority of native load to retail customers, and infringes on the FERC's power to give native load status to wholesale customers. The Companies concede that a simple notice provision for information may be acceptable, but argue that setting the process up under the detailed procedures of Regulatory Condition 13.2 clearly amounts to a gatekeeping function.

9. Regulatory Condition 3.8(b)-(e) - Additional Provisions Regarding Wholesale Contracts Entered Into by DEC or DEP as Sellers – The Companies state that these provisions provide that the NCUC retains the right to assign, allocate, impute and make pro-forma adjustments with respect to the revenues and costs associated with both DEC's and DEP's wholesale contracts for retail ratemaking and regulatory accounting and reporting purposes; and that DEC and DEP (or affiliates) shall not assert that the Commission's authority to do so is subject to preemption. The Companies contend that this language appears to be contrary to law and that the Commission cannot simply ignore the actions by the FERC related to wholesale ratemaking matters. The Companies argue that to the extent that the Commission or Public Staff believes that a FERC decision impinges on State retail ratemaking authority, the proper remedy is to file a petition with the FERC.

10. Regulatory Condition 3.9 (a)-(c), (g) & (g)(vii) - Other Provisions – The Companies state that these provisions allow the Commission to intrude on federal jurisdiction by requiring the Companies not to assert that FERC approval preempts the Commission's authority and are likely to be preempted. Sections (c) and (d) specifically amount to another gatekeeping function. Section (g)(vii) attempts to prevent the FERC from implementing decisions that could affect North Carolina ratepayers.

11. Regulatory Condition 3.10 - FERC Filings and Orders – The Companies contend that this provision has been edited in accordance with the regulatory compact to require the Companies to keep the Commission appropriately informed of their activities. Regulatory Condition 13.2 - Advance Notice Filings - which is essentially a procedural provision. According to the Companies, although this provision could be defined as the Commission serving as gatekeeper to Federal Jurisdiction, the proposed changes to Regulatory Conditions 3.1, 3.3, and 3.9 effectively remove the gatekeeper role of the Commission for the purposes outlined in those sections. Therefore, it may be unnecessary to change this procedural provision.

The Companies conclude by arguing that the best course of action is for the Commission to address the gatekeeping issues that have been questioned as opposed to waiting for FERC to take preemptive action.

Comments of the Public Staff

On July 12, 2018, the Public Staff – North Carolina Utilities Commission (Public Staff) filed Comments Regarding Motion to Amend Regulatory Conditions. The Public Staff largely agrees with the Companies' analysis regarding the D.C. Circuit's opinion in Orangeburg, and the FERC's Order Rejecting As-Available Capacity Sales Agreement. Further, the Public Staff does not object to most of the revisions to the Regulatory Conditions proposed by the Companies, indicating that most of the revisions will reduce or eliminate the risk of more pervasive preemption of the Commission's authority by FERC.

However, the Public Staff does oppose certain proposed revisions as being unnecessary to address the federal jurisdictional issues raised by FERC and the D.C. Circuit. The Public Staff contends that any revisions to the Regulatory Conditions should be narrowly tailored to achieve the overall goals of reducing potential violations of federal law and avoiding a more pervasive preemption of Commission authority. The Public Staff states that this is "best achieved by (1) eliminating the "gatekeeping" provisions that require advance Commission proceedings to approve, reject or modify the Companies' filings at FERC and (2) eliminating provisions that prohibit the Companies from waiving certain federal rights that might limit FERC's ability to exercise its jurisdiction under federal law."

The Public Staff attached Attachment A, labeled Revised Appendix A, to its filing which is a redlined version of the Regulatory Conditions identifying the revisions to the Regulatory Conditions proposed by the Companies, as modified by the revisions proposed by the Public Staff.

In its Comments the Public Staff provides the following specifics regarding revisions to various provisions of the Regulatory Conditions:

1. Regulatory Condition 3.1(c) – While the Public Staff does not object to deleting the language in this condition, the Companies should continue to file, for informational purposes, proposed Affiliate Contracts or proposed amendments to existing Affiliate Contracts that are required to be filed with FERC, with the Commission at least 15 days prior to filing with FERC. The Public Staff has added a new regulatory condition, which is numbered as Regulatory Condition 3.1(b), to address this issue.

2. Regulatory Condition 3.7(d) – The Public staff indicates that there is considerable value in obtaining written advance notice of any contract wherein DEC or DEP intend to grant Native Load Priority to wholesale customers, and to the extent such contracts raise issues that may impact DEC's or DEP's customers, advance notice provides transparency. The Public Staff disagrees with the Companies' proposal to delete this regulatory condition in its entirety. The Public Staff notes that simply requiring DEC and DEP to provide advance notice prior to the execution of any contract that grants Native Load Priority to a wholesale customer does not infringe upon FERC's jurisdiction over wholesale contracts. The Public Staff contends that the jurisdictional issues arise out of the procedure set forth in Regulatory Condition 13.2, which subjects proposed contracts to the approval of, or modification by, the Commission prior to execution and filing with FERC. The Public Staff asserts those issues can be addressed by deleting the second sentence that subjects such

contracts to the provisions set forth in Regulatory Condition 13.2, thus leaving in place the advance notice provision. The Public Staff notes that while Regulatory Conditions 3.5, 3.6, and 4.5 are referenced in Regulatory Condition 3.7(d), none of those regulatory conditions are implicated in the D.C. Circuit opinion, recent FERC orders, or the Companies' proposed revisions. The Public Staff does not oppose deleting the second sentence of Regulatory Condition 3.7(d), but recommends that DEC and DEP be required to provide the Public Staff with at least 15 days' written advance notice for informational purposes.

3. Regulatory Condition 3.8(c) – The Public Staff agrees that this regulatory condition, as currently drafted, raises jurisdictional issues that may conflict with federal law. While the Public Staff does not object to some of the Companies' proposed revisions to this condition, the Public Staff objects to the deletion of language that reaffirms the Commission's authority under Chapter 62 to disallow uneconomic sunk costs and the language that describing "used and useful" capacity. The Public Staff argues that this language does not constitute gatekeeping language that might deprive FERC of the ability to exercise its federal jurisdiction. The Public Staff asserts that the language merely reaffirms established Chapter 62 ratemaking principles and ensures that retail customers are not on the hook for imprudent decisions made with respect to DEC and DEP wholesale operations. The Public Staff does not object to the deletion of the final sentence of this section, which raises federal jurisdictional issues.

4. Regulatory Condition 3.9(c) – The Public Staff does not oppose the deletion of the last sentence that removes the approval procedures set forth in Regulatory Condition 13.2. However, the Public Staff asserts that the requirement to file notice "at least 15 days prior to filing with the FERC" should remain in the first sentence. The Public Staff states that the removal of the procedures set forth in Regulatory Condition 13.2 renders the advance notice an informational filing, which does not present federal jurisdictional issues and does not limit FERC's authority in any way. The Public Staff recommends the Commission leaves the 15 day filing requirement in place as an informational filing, and language was added to clarify that notices are for informational purposes.

5. Regulatory Condition 3.9(g)(vii) – The Public Staff does not oppose the deletion of the last sentence that removes language obligating the Companies to take actions that may infringe upon federal law. The Public Staff argues that the remaining language should not be deleted as it underscores the allocation of risk between the Companies and North Carolina retail customers; it also directs the Companies to take action to protect North Carolina ratepayers against any adverse effects from preemption. The Public Staff contends that the Companies should be obligated to take reasonably necessary and appropriate actions to protect North Carolina retail ratepayers. The Public Staff posits that if FERC deems such actions to be inappropriate, it retains the jurisdictional authority to modify or nullify them. The Public Staff states that the remaining language in this section does not constitute issue gatekeeping, does not obligate the Companies to take action that may infringe on federal jurisdiction, and does not limit FERC's authority in any way. Lastly, the Public Staff states that the remaining language was edited to be an acknowledgment of the risk of any possible preemptive effects of Federal Law, and that this Regulatory Condition was relabeled as 3.9(h).

Response by the Companies

On July 17, 2018, the Companies filed a letter indicating that the Companies agree with the Public Staff and support the changes to the Regulatory Conditions as submitted in Revised Appendix A. The Companies further state that they have been authorized by counsel for Orangeburg to represent that the changes in Revised Appendix A are also acceptable to Orangeburg and that Orangeburg is prepared to notify the FERC that they are satisfied with the resolution of the issues at this Commission provided that the amendments are approved as outlined in Revised Appendix A.

Commission Determination

The Commission agrees with the Companies and the Public Staff that in light of the decision in Orangeburg v. FERC, 862 F.3d 1071 (D.C. Cir. 2017) (Orangeburg) in which the D.C. Circuit vacated the FERC's approval of the JDA and remanded the case to the FERC, and the FERC's order in which the FERC rejected DEC's and DEP's petition for approval of an affiliate As-Available Capacity Sales Agreement, Order Rejecting As-Available Capacity Sales Agreement, 161 FERC ¶ 61,029, October 10, 2017, the Commission should revise the Regulatory Conditions. The Commission agrees with the Public Staff that the proposed revisions to the Regulatory Conditions should be narrowly tailored to achieve the overall goals of reducing potential violations of federal law and avoiding a more pervasive preemption of Commission authority. The Commission finds that this balance is best achieved by (1) eliminating the "gatekeeping" provisions that require advance Commission proceedings to approve, reject or modify the Companies' filings at FERC, and (2) eliminating provisions that require the Companies to waive certain federal rights, including provisions prohibiting the Companies from taking any action or making any assertion that the NCUC's actions are preempted by Federal Law or are otherwise not within the NCUC's jurisdiction.

The Commission concludes that by eliminating said aforementioned provisions from the Regulatory Conditions, the Commission will be resolving the issues and concerns presented by the D.C. Circuit and the FERC's order regarding As-Available Capacity Sales surrounding preferential treatment, violations of the Federal Power Act, preemption, and the Commerce Clause. As a result, the Commission finds it appropriate to revise and amend the Regulatory Conditions approved in the Duke Energy/Piedmont Merger as set forth in Revised Appendix A attached to the Public Staff's July 12, 2018 filing. The Companies indicated agreement with the Public Staff's revisions to the Company's proposed amendments and further indicated that Orangeburg finds the amendments acceptable and that Orangeburg is prepared to notify the FERC that Orangeburg would be satisfied with the resolution of the issues at this Commission if such amendments are made. No other party has filed comments or opposed the proposed amendments to the Regulatory Conditions.

IT IS, THEREFORE, ORDERED as follows:

1. That the Regulatory Conditions approved in the Duke Energy/Piedmont Merger are amended as set forth in Revised Appendix A attached to the Public Staff's July 12, 2018 filing and as agreed to by the Companies in its July 17, 2018 filing.

2. That a strike-through and underlined version of the revisions of the Regulatory Conditions is attached to this order as Appendix A and a clean version is attached as Appendix B.

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of August, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

Commissioner James G. Patterson and Commissioner Daniel G. Clodfelter did not participate in this decision.

APPENDIX A

DOCKET NO. E-2, SUB 1095
DOCKET NO. E-7, SUB 1100
DOCKET NO. G-9, SUB 682

REGULATORY CONDITIONS AND CODE OF CONDUCT

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REGULATORY CONDITIONS

These Regulatory Conditions set forth commitments made by Duke Energy Corporation (Duke Energy) and its public utility subsidiaries, Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP), and Piedmont Natural Gas Company, Inc. (Piedmont), as a precondition of approval of the application by Duke Energy and Piedmont pursuant to G.S. 62-111(a) for authority to engage in their proposed business combination transaction. These Regulatory Conditions, which become effective only upon closing of the Merger, shall apply jointly and severally to Duke Energy, DEC, DEP, and Piedmont, and shall be interpreted in the manner that most effectively fulfills the Commission's purposes as set forth in the preamble to Section II of these Regulatory Conditions.

SECTION I
DEFINITIONS

For the purposes of these Regulatory Conditions, capitalized terms shall have the meanings set forth below. If a capitalized term is not defined below, it shall have the meaning provided elsewhere in this document or as commonly used in the electric or natural gas utility industry.

Affiliate: Duke Energy and any business entity of which ten percent (10%) or more is owned or controlled, directly or indirectly, by Duke Energy. For purposes of these Regulatory Conditions, Duke Energy and each business entity so controlled by it are considered to be Affiliates of DEC, DEP, and Piedmont, and DEC, DEP, and Piedmont are considered to be Affiliates of each other.

Affiliate Contract: (a) Any contract or agreement between or among DEC, DEP, and Piedmont or between or among DEC, DEP, or Piedmont and any other Affiliate or proposed Affiliate, and (b) any contract or agreement between such other Affiliate or proposed Affiliate and another Affiliate that is related to the same subject matter and is reasonably likely to have an Effect on DEC's, DEP's, or Piedmont's Rates or Service. Such contracts and agreements include, but are not limited to, service, operating, interchange, pooling, wholesale power sales agreements and agreements involving financings and asset transfers and sales, and the Joint Dispatch Agreement.

Catawba Joint Owners: The North Carolina Electric Membership Corporation, North Carolina Municipal Power Agency No. 1, and Piedmont Municipal Power Agency. For purposes of these Regulatory Conditions, DEC is not included in the definition of Catawba Joint Owners.

Code of Conduct: The minimum guidelines and rules approved by the Commission that govern the relationships, activities, and transactions between and among the public utility operations of DEC, DEP, and Piedmont, Duke Energy, the other Affiliates of DEC, DEP, and

Piedmont, and the Nonpublic Utility Operations of DEC, DEP, and Piedmont, as those guidelines and rules may be amended by the Commission from time to time.

Commission: The North Carolina Utilities Commission.

Customer: Any retail electric customer of DEC or DEP in North Carolina and any Commission-regulated natural gas sales or natural gas transportation customer of Piedmont located in North Carolina.

DEBS: Duke Energy Business Services, LLC, and its successors, which is a service company Affiliate that provides Shared Services to DEC, DEP, Piedmont, Duke Energy, other Affiliates, or the Nonpublic Utility Operations of DEC, DEP or Piedmont, singly or in any combination.

DEC: Duke Energy Carolinas, LLC, the business entity, wholly owned by Duke Energy, that holds the franchise granted by the Commission to provide Electric Services within DEC's North Carolina service territory and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

DEP: Duke Energy Progress. LLC, the business entity, wholly owned by Duke Energy, that holds the franchises granted by the Commission to provide Electric Services within the DEP's North Carolina service territory and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

Duke Energy: Duke Energy Corporation, which is the current holding company parent of DEC, DEP, and Piedmont, and any successor company.

Effect on DEC's, DEP's, or Piedmont's Rates or Service: When used with reference to the consequences to DEC, DEP, or Piedmont of actions or transactions involving an Affiliate or Nonpublic Utility Operation, this phrase has the same meaning that it has when the Commission interprets G.S. 62-3(23)(c) with respect to the affiliation covered therein.

Electric Services: Commission-regulated electric power generation, transmission, distribution, delivery, and sales, and other related services, including, but not limited to, administration of Customer accounts and rate schedules, metering, billing, standby service, backups, and changeovers of service to other suppliers.

Federal Law: Any federal statute or legislation, or any regulation, order, decision, rule or requirement promulgated or issued by an agency or department of the federal government.

FERC: The Federal Energy Regulatory Commission.

Fully Distributed Cost: All direct and indirect costs, including overheads and an appropriate cost of capital, incurred in providing goods or services to another business entity; provided, however, that (a) for each good or service supplied by or from DEC, DEP, or Piedmont, the return on common equity utilized in determining the appropriate cost of capital shall equal the return on common equity authorized by the Commission in the supplying utility's most recent general rate case proceeding, (b) for each good or service supplied to DEC, DEP, or Piedmont, the appropriate cost of capital shall not exceed the overall cost of capital authorized in the supplying utility's most recent general rate case proceeding; and (c) for each good or service supplied by or from DEC, DEP, or Piedmont to each other, the return on common equity utilized in determining the appropriate cost of capital shall not exceed the lower of the returns on common equity authorized by the Commission in DEC's, DEP's, or Piedmont's most recent general rate case proceeding, as applicable.

JDA: Joint Dispatch Agreement, which is the agreement as filed with the Commission in Docket Nos. E-7, Sub 986, and E-2, Sub 998, on June 22, 2011, and as amended and refiled on June 12, 2012.

Market Value: The price at which property, goods, or services would change hands in an arm's length transaction between a buyer and a seller without any compulsion to engage in a transaction, and both having reasonable knowledge of the relevant facts.

Merger: All transactions contemplated by the Agreement and Plan of Merger between Duke Energy and Piedmont.

Native Load Priority: Power supply service being provided or electricity otherwise being sold with a priority of service equivalent to that planned for and provided by DEC or DEP to their respective Retail Native Load Customers.

Natural Gas Services: Commission-regulated natural gas sales and natural gas transportation, and other related services, including, but not limited to, administration of Customer accounts and rate schedules, metering and billing, and standby service.

Non-Native Load Sales: DEC's or DEP's sales of energy at wholesale, not including transactions between DEC and DEP pursuant to the JDA and not including service to customers served at Native Load Priority.

Nonpublic Utility Operations: All business operations engaged in by DEC, DEP, or Piedmont involving activities (including the sales of goods or services) that are not regulated by the Commission or otherwise subject to public utility regulation at the state or federal level.

Non-Utility Affiliate: Any Affiliate, including DEBS, other than a Utility Affiliate, DEC, DEP, or Piedmont.

Piedmont: Piedmont Natural Gas Company, Inc., the business entity, wholly owned by Duke Energy, that holds the franchise granted by the Commission to provide Natural Gas Services within its North Carolina service territory and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

Progress Energy: Progress Energy, Inc., which is the former holding company parent of DEP and is a subsidiary of Duke Energy, and any successors.

Public Staff: The Public Staff of the North Carolina Utilities Commission.

PUHCA 2005: The Public Utility Holding Company Act of 2005.

Purchased Power Resources: Purchases of energy by DEC or DEP at wholesale from sellers other than each other, the contract terms for which are one year or longer.

Retail Native Load Customers: The captive retail Customers of DEC and DEP in North Carolina for which DEC and DEP have the obligation under North Carolina law to engage in long-term planning and to supply all Electric Services, including installing or contracting for capacity, if needed, to reliably meet their electricity needs.

Retained Earnings: The retained earnings currently required to be listed on page 112, line 11, of the pre-Merger DEC FERC Form 1, the pre-Merger DEP FERC Form 1, and page 112, line 11 of the pre-Merger Piedmont FERC Form 2.

Shared Services: The services that meet the requirements of these Regulatory Conditions and that the Commission has explicitly authorized DEC, DEP, and Piedmont to take from DEBS pursuant to a service agreement (a) filed with the Commission pursuant to G.S. 62-153(b), thus requiring acceptance and authorization by the Commission, and (b) subject to all other applicable provisions of North Carolina law, the rules and orders of the Commission, and these Regulatory Conditions.

Utility Affiliates: The regulated public utility operations of Duke Energy Indiana, LLC (Duke Indiana), Duke Energy Kentucky, Inc. (Duke Kentucky), Florida Power Corporation, d/b/a Duke Energy Florida, LLC (DEF), and Duke Energy Ohio, Inc. (Duke Ohio).

SECTION II
AUTHORITY, SCOPE, AND EFFECT

These Regulatory Conditions are based on the general power and authority granted to the Commission in Chapter 62 of the North Carolina General Statutes to control and supervise the public utilities of the State. The Regulatory Conditions ~~(a) constitute~~address specific exercises of the Commission's authority~~, (b)~~ and provide mechanisms that enable the Commission to determine ~~in advance~~ the extent of its authority and jurisdiction over proposed activities of, and transactions involving, DEC, DEP, Piedmont, Duke Energy, other Affiliates or Nonpublic Utility Operations~~, and (c) protect the Commission's jurisdiction from federal preemption and its effects~~. The purpose of these Regulatory Conditions is to ensure that DEC's and DEP's Retail Native Load Customers and Piedmont's Customers (a) are protected from any known adverse effects from the Merger, (b) are protected as much as possible from potential costs and risks resulting from the Merger, and (c) receive sufficient known and expected benefits to offset any potential costs and risks resulting from the Merger. These Regulatory Conditions are not intended to impose legal obligations on entities in which Duke Energy does not directly or indirectly have a controlling voting interest, or to affect any rights of any party to participate in subsequent proceedings.

2.1 ~~Waiver of Certain~~ Commission Authority Over Certain Transactions~~Federal Rights~~. ~~Pursuant to these conditions,~~ DEC, DEP, Piedmont, Duke Energy, and other Affiliates acknowledge that the Commission has authority over intra-company transactions ~~waive certain of their federal rights as specified in these Regulatory Conditions, but do not otherwise agree that the Commission has authority other than~~ as provided for in Chapter 62.

2.2 Limited Right to Challenge Commission Orders. Other than as provided for, or explicitly prohibited, in these conditions, Duke Energy, DEC, DEP, Piedmont, and other Affiliates retain the right to challenge the lawfulness of any Commission order issued pursuant to or relating to these Regulatory Conditions on the basis that such order exceeds the Commission's statutory authority under North Carolina or Federal law or the other grounds listed in G.S. 62-94(b).

2.3 Waiver Request. DEC, DEP, Piedmont, Duke Energy, and other Affiliates may seek a waiver of any aspect of these Regulatory Conditions in a particular case or circumstance for good cause shown by filing a such request with the Commission.

SECTION III
PROTECTION OF RIGHTS~~FROM PREEMPTION~~

The following Regulatory Conditions are intended to protect the jurisdiction of the Commission ~~against the risk of federal preemption~~ as a result of the Merger, including risks related to agreements and transactions between and among DEC, DEP, Piedmont, and any of their Affiliates; financing transactions involving Duke Energy, DEC, DEP, or Piedmont, and any other Affiliate; and the ownership, use, and disposition of assets by DEC, DEP, or Piedmont~~; participation in the wholesale market by DEC or DEP; and filings with federal regulatory agencies~~.

3.1 Transactions between DEC, DEP, Piedmont, and Other Affiliates~~; Affiliate Contract Provisions; Advance Notice of Affiliate Contracts to be Filed with the FERC; Annual Certification;~~ Notice of Affiliate Contracts to be Filed with the FERC.

(a) DEC, DEP, and Piedmont shall not engage in any transactions with Affiliates or proposed Affiliates without first filing the proposed contracts or agreements memorializing such transactions pursuant to G.S. 62-153 and taking such actions and obtaining from the Commission such determinations and authorizations as may be required under North Carolina law. DEC, DEP, or Piedmont, as applicable, shall submit each proposed Affiliate Contract or substantive amendment to an existing Affiliate Contract to the Public Staff for informal review at least 15 days before filing it with the Commission. If DEC, DEP, or Piedmont and the Public Staff agree within the 15-day period that the proposed Affiliate Contract or substantive amendment to an existing Affiliate Contract does not require any action by the Commission, DEC, DEP, or Piedmont may proceed to execute the agreement subject to later disapproval and voidance by the Commission pursuant to G.S. 62-153(a). Otherwise, the proposed Affiliate Contract or substantive amendment to an existing Affiliate Contract shall not be executed until the agreement has been filed and payment of compensation has been approved by the Commission pursuant to G.S. 62-153(b). ~~No formal advance notice pursuant to Regulatory Condition 13.2 is required for such agreements unless the agreements are to be filed with the FERC, in which case subsection (c) applies.~~

~~(b) All Affiliate Contracts to which DEC, DEP, or Piedmont is a party shall contain the following provisions:~~

~~(i) DEC's, DEP's, or Piedmont's participation in the agreement is voluntary, DEC, DEP, or Piedmont is not obligated to take or provide services or make any purchases or sales pursuant the agreement, and DEC, DEP, or Piedmont may elect to discontinue its participation in the agreement at its election after giving any required notice;~~

~~(ii) DEC, DEP, or Piedmont may not make or incur a charge under the agreement except in accordance with North Carolina law and the rules, regulations and orders of the Commission promulgated thereunder;~~

~~(iii) DEC, DEP, or Piedmont may not seek to reflect in rates any (A) costs incurred under the agreement exceeding the amount allowed by the Commission or (B) revenue level earned under the agreement less than the amount imputed by the Commission; and~~

~~(iv) DEC, DEP, or Piedmont shall not assert in any forum—whether judicial, administrative, federal, state, local or otherwise—either on its own initiative or in support of another entity's assertions, that the Commission's authority to assign, allocate, impute, make pro forma adjustments to, or disallow revenues and costs for retail ratemaking and regulatory accounting and reporting purposes is, in whole or in part, (A) preempted by Federal Law or (B) not within the Commission's power, authority or jurisdiction; DEC, DEP, and Piedmont will bear the full risk of any preemptive effects of Federal Law with respect to the agreement.~~

~~(c) To enable the Commission to determine and exercise its lawful authority and jurisdiction over a proposed Affiliate Contract or amendment to an existing Affiliate Contract that involves costs that will be assigned to DEC, DEP, or Piedmont and that is required or intended to be filed with the FERC, the following procedures shall apply:~~

~~(i) DEC DEP, or Piedmont shall file advance notice and a copy of the proposed Affiliate Contract, a contract with a proposed Affiliate, or an amendment to an existing Affiliate Contract with the Commission at least 30 days prior to a filing with the FERC. All Affiliate Contracts, contracts with a proposed Affiliate, or amendments to existing Affiliate Contracts filed with the advance notice under Regulatory Condition 3.1(c) shall be unexecuted at the time of filing and remain unexecuted for the duration of the advance notice period. If, consistent with Regulatory Condition 13.2(h), the Commission extends the advance notice period, the Affiliate Contract, contract with a Proposed Affiliate, or~~

~~amendments to existing Affiliate Contracts shall remain unexecuted until the Commission issues an order on the advance notice or the extension of the advance notice period expires without a Commission order, procedural or substantive, being issued. A copy shall be provided to the Public Staff at the time of the filing. The provisions of Regulatory Condition 13.2 shall apply to an advance notice filed pursuant to this Regulatory Condition.~~

~~(ii) If an objection to DEC, DEP, or Piedmont proceeding with the filing with the FERC is filed pursuant this Regulatory Condition, the proposed filing shall not be executed and made with the FERC until the Commission issues an order resolving the objection.~~

~~(iii) Filings of advance notices and copies of proposed Affiliate Contracts, a contract with a proposed Affiliate, and amendments to existing Affiliate Contracts pursuant to this subsection shall be in addition to filings required by G.S. 62-153, and the burden of proof as to those filings shall be as provided by statute.~~

~~(d) DEC, DEP, and Piedmont shall each certify in a filing with the Commission that (i) it has not made any filing with the FERC or any other federal regulatory agency inconsistent with the foregoing and (ii) Duke Energy, any other Affiliate and any Nonpublic Utility Operation has not made any such filing. Such certification shall be repeated annually on the anniversary of the first certification.~~

~~(e) In the event the FERC or any other federal regulatory agency requires modification of a proposed Affiliate Contract to omit any of the provisions of Regulatory Condition 3.1(b) as a condition of acceptance or approval by that agency, DEC, DEP or Piedmont shall remain bound by those provisions for state regulatory purposes.~~

<u>(b) In addition to the requirements of Regulatory Condition 3.1(a), for any contract requiring filing with FERC, DEC, DEP, or Piedmont shall file, for informational purposes, a copy of a proposed Affiliate Contract, a contract with a proposed Affiliate, or an amendment to an existing Affiliate Contract with the Commission at least 15 days prior to filing with FERC.</u>

3.2 <u>Financing Transactions Involving DEC, DEP, Piedmont, Duke Energy, or Other Affiliates</u>.

(a) With respect to any financing transaction between or among DEC, DEP, or Piedmont and Duke Energy or any one or more other Affiliates, any contract memorializing such transaction shall expressly provide that DEC, DEP, or Piedmont shall not enter into any such financing transaction except in accordance with North Carolina law and the rules, regulations and orders of the Commission promulgated thereunder; and

(b) With respect to any financing transaction (i) between or among any of the Affiliates if such contracts are reasonably likely to have an Effect on DEC's, DEP's, or Piedmont's Rates or Service, or (ii) between or among DEC, DEP, and Piedmont or between DEC, DEP, or Piedmont and any other Affiliate, any contract memorializing such transaction shall expressly provide that DEC, DEP, or Piedmont shall not include the effects of any capital structure or debt or equity costs associated with such financing transaction in its North Carolina retail cost of service or rates except as allowed by the Commission.

3.3 Ownership and Control of Assets Used by DEC, DEP, and Piedmont to Supply Electric Power or Natural Gas Services to North Carolina Customers; Transfer of Ownership or Control.

(a) DEC, DEP, and Piedmont shall own and control all assets or portions of assets used for the generation, transmission, and distribution of electric power or the transmission, storage, or distribution of natural gas to their respective Customers (with the exception of assets solely used to provide power purchased by DEC or DEP at wholesale).

(b) With respect to the transfer by DEC, DEP, or Piedmont to any entity, affiliated or not, of the control of, operational responsibility for, or ownership of generation, transmission, or distribution assets with a gross book value in excess of ten million dollars ($10 million), DEC, DEP, or Piedmont shall provide written notice to the Commission at least 30 days in advance of the proposed transfer. The provisions of Regulatory Condition 13.2 shall apply to an advance notice filed pursuant to this Regulatory Condition.

(c) Any contract memorializing such a transfer shall include the following language:

(i) DEC, DEP, or Piedmont may not commit to or carry out the transfer except in accordance with applicable law, and the rules, regulations and orders of the Commission promulgated thereunder; and

(ii) DEC, DEP, or Piedmont may not include in its North Carolina cost of service or rates the value of the transfer, ~~whether or not subject to federal law,~~ except as allowed by the Commission in accordance with North Carolina law.

~~(d) Any application filed with the FERC in connection with any transfer of control, operational responsibility, or ownership that involves or potentially affects DEC, DEP, or Piedmont shall include the language set forth in subdivisions (c)(i) and (ii), above.~~

3.4 Purchases and Sales of Electricity and Natural Gas between DEC, DEP, Piedmont, and Duke Energy, Other Affiliates, or Nonpublic Utility Operations. Subject to additional restrictions set forth in the Code of Conduct, neither DEC, DEP, nor Piedmont shall purchase electricity (or related ancillary services) or natural gas from Duke Energy, another Affiliate, or a Nonpublic Utility Operation under circumstances where the total all-in costs, including generation, transmission, ancillary costs, distribution, taxes and fees, and delivery point costs, incurred (whether directly or through allocation), based on information known, anticipated, or reasonably available at the time of purchase, exceed fair Market Value for comparable service, nor shall DEC, DEP, or Piedmont sell electricity (or related ancillary services) or natural gas to Duke Energy, another

Affiliate, or a Nonpublic Utility Operation for less than fair Market Value; provided, however, that such restrictions shall not apply to emergency transactions. This condition shall not apply to transactions between DEC and DEP that are governed by the JDA.

3.5 Least Cost Integrated Resource Planning and Resource Adequacy. This Regulatory Condition does not apply to Piedmont. DEC and DEP shall retain the obligation to pursue least cost integrated resource planning for their respective Retail Native Load Customers and remain responsible for their own resource adequacy subject to Commission oversight in accordance with North Carolina law. DEC and DEP shall determine the appropriate self-built or purchased power resources to be used to provide future generating capacity and energy to their respective Retail Native Load Customers, including the siting considered appropriate for such resources, on the basis of the benefits and costs of such siting and resources to those Retail Native Load Customers.

3.6 Priority of Service.

(a) This Regulatory Condition does not apply to Piedmont.
(b) The planning and joint dispatch of DEC's system generation and Purchased Power Resources shall ensure that DEC's Retail Native Load Customers receive the benefits of that generation and those resources, including priority of service, to meet their electricity needs consistent with the JDA. DEC shall continue to serve its Retail Native Load Customers with the lowest-cost power it can reasonably generate or obtain as Purchase Power Resources before making power available for sales to customers that are not entitled to the same level of priority as Retail Native Load Customers.
(c) The planning and joint dispatch of DEP's system generation and Purchase Power Resources shall ensure that DEP's Retail Native Load Customers receive the benefits of that generation and those resources, including priority of service, to meet their electricity needs consistent with the JDA. DEP shall continue to serve its Retail Native Load Customers with the lowest-cost power it can reasonably generate or obtain as Purchase Power Resources before making power available for sales to customers that are not entitled to the same level of priority as Retail Native Load Customers.

3.7 Wholesale Power Contracts Granting Native Load Priority.

(a) This Regulatory Condition does not apply to Piedmont.
(b) DEC is not required to ~~file an advance notice with~~notify the Commission ~~or receive its approval prior to entering~~when it enters into wholesale power contracts that grant Native Load Priority to the following historically served customers: the City of Concord, North Carolina; the City of Kings Mountain, North Carolina; the Town of Dallas, North Carolina; the Town of Forest City, North Carolina; Lockhart Power Company; the Public Works Commission of the Town of Due West, South Carolina; the Town of Prosperity, South Carolina; the City of Greenwood, South Carolina; the Town of Highlands; North Carolina; Western Carolina University

(WCU); the electric membership cooperatives (EMCs) within DEC's control area; North Carolina Municipal Power Agency No. 1; Piedmont Municipal Power Agency; New River Light & Power Company; and the South Carolina distribution cooperatives historically served by Saluda River Electric Cooperative, Inc., and currently served by Central Electric Power Cooperative, Inc. (which are Blue Ridge Electric Cooperative, Inc., Broad River Electric Cooperative Inc., Laurens Electric Cooperative, Inc., Little River Electric Cooperative, Inc., and York Electric Cooperative, Inc.). Subject to the conditions set out in Regulatory Condition 3.8, the retail native loads of these historically served wholesale customers shall be considered DEC's Retail Native Load Customers for purposes of Regulatory Conditions 3.5, 3.6, and 4.5; provided, however, that this subsection applies only to the same types of supplemental load and backstand requirements services that were historically provided to the Catawba Joint Owners under the Catawba Interconnection Agreements between DEC and the Catawba Joint Owners prior to 2001, which, for the North Carolina Electric Membership Corporation, only includes the EMCs within DEC's control area.

(c) DEP is not required to ~~file an advance notice with~~notify the Commission ~~or receive its approval prior to entering~~when it enters into wholesale power contracts that grant Native Load Priority to the Public Works Commission of the City of Fayetteville, North Carolina; the Town of Waynesville, North Carolina; the City of Camden, South Carolina; the French Broad Electric Membership Corporation; the North Carolina Eastern Municipal Power Agency; the electric membership cooperatives (EMCs) within DEP's control area, whether served through the North Carolina Electric Membership Corporation (NCEMC) or individually; the Town of Black Creek, North Carolina; the Town of Lucama, North Carolina; the Town of Stantonsburg, North Carolina; the Town of Sharpsburg, North Carolina; and the Town of Winterville, North Carolina. Subject to the conditions set out in Regulatory Condition 3.8, the retail native loads of these historically served wholesale customers shall be considered DEP's Retail Native Load Customers for purposes of Regulatory Conditions 3.5, 3.6, and 4.5.

~~(d) Before either DEC or DEP executes any contract that grants Native Load Priority to a wholesale customer (other than as set forth in subdivisions (a) and (b) above) or to one or more retail customers of another entity, it must provide the Commission with at least 30 days' written advance notice of its intent to grant Native Load Priority and to treat the retail native load of a proposed wholesale customer as if it were DEC's or DEP's retail native load pursuant to Regulatory Conditions 3.5, 3.6, and 4.5. The provisions set forth in Condition 13.2 shall apply to an advance notice filed pursuant to this Regulatory Condition.~~

(d) Before either DEC or DEP executes any contract that grants Native Load Priority to a wholesale customer (other than as set forth in subdivisions (a) and (b) above) or to one or more retail customers of another entity, it shall, for informational purposes, provide the Public Staff with at least 15 days' written advance notice of its intent to grant Native Load Priority and to treat the retail native load of a proposed wholesale customer as if it were DEC's or DEP's retail native load pursuant to Regulatory Conditions 3.5, 3.6, and 4.5.

3.8 Additional Provisions Regarding Wholesale Contracts Entered into by DEC or DEP as Sellers.

(a) This Regulatory Condition does not apply to Piedmont.

(b) The Commission retains the right to assign, allocate, impute, and make pro-forma adjustments with respect to the revenues and costs ~~associated with both DEC's or DEP's wholesale contracts~~ for retail ratemaking and regulatory accounting and reporting purposes.

(c) DEC and DEP acknowledge that when either DEC or DEP enters ~~Entry~~ into wholesale contracts that grant Native Load Priority or otherwise obligate DEC or DEP to construct generating facilities or make commitments to purchase capacity and energy to meet those contractual commitments such action constitutes acceptance by DEC, DEP, Duke Energy, and other Affiliates or Nonpublic Utility Operations thereof of the risks that investments in generating facilities or commitments to purchase capacity and energy to meet such contractual commitments and maintain an adequate reserve margin throughout the term of such contracts may become uneconomic sunk costs that ~~are~~may not be ~~not~~ recoverable from DEC's or DEP's respective Retail Native Load Customers. In a future Commission retail proceeding in which cost recovery is at issue, neither DEC nor DEP shall claim that it does not bear this risk, and both DEC and DEP shall acknowledge that the Commission retains full authority under Chapter 62 to ascertain whether such costs are used and useful. For purposes of this condition, capacity will be considered used and useful and not excess capacity to the extent the Commission determines such capacity is needed by DEC or DEP to meet the expected peak loads of DEC's or DEP's respective Retail Native Load Customers in the near term future plus a reserve margin comparable to that currently being used or otherwise considered appropriate by the Commission~~, and both DEC and DEP shall acknowledge that the Commission retains full authority under Chapter 62 to disallow such costs as not used and useful and to allocate, impute, or assign such costs away from Retail Native Load Customers. For purposes of this condition, capacity will be considered used and useful and not excess capacity to the extent the Commission determines such capacity is needed by DEC or DEP to meet the expected peak loads of DEC's or DEP's respective Retail Native Load Customers in the near term future plus a reserve margin comparable to that currently being used or otherwise considered appropriate by the Commission. Neither DEC, DEP, Duke Energy, nor any other Affiliate shall assert in any forum —whether judicial, administrative, federal, state, local or otherwise—either on its own initiative or in support of any other entity's assertions that the Commission is preempted from taking the actions contemplated in this subsection~~.

~~(d) Neither DEC, nor DEP, nor Duke Energy, nor other Affiliate shall assert in any forum—whether judicial, administrative, federal, state, local or otherwise—either on its own initiative or in support of any other entity's assertions that (i) transactions entered into pursuant to DEC's or DEP's cost- or market-based rate authority or (ii) the filing with, or acceptance for filing by, the FERC of any wholesale power contract to which either is a party establishes or implies a cost allocation methodology that is binding on the Commission, requires the pass-~~

~~through of any costs or revenues under the filed rate doctrine, or preempts the Commission's authority to assign, allocate, impute, make pro forma adjustments to, or disallow the revenues and costs associated with, DEC's or DEP's wholesale contracts for retail ratemaking and regulatory accounting and reporting purposes.~~

~~(e)~~ ~~Neither DEC, nor DEP, nor Duke Energy, nor other Affiliate shall assert in any forum—whether judicial, administrative, federal, state, local or otherwise—either on its own initiative or in support of any other entity's assertions that the exercise of authority by the Commission to assign, allocate, impute, make pro forma adjustments to, or disallow the costs and revenues associated with DEC's or DEP's wholesale contracts for retail ratemaking and regulatory accounting and reporting purposes in itself constitutes an undue burden on interstate commerce or otherwise violates the Commerce Clause of the United States Constitution. DEC and DEP, however, retain the right to argue that a specific exercise of authority by the Commission violates the Commerce Clause based upon specific evidence of undue interference with interstate commerce.~~

(~~f~~d) Except as provided in the foregoing conditions, DEC and DEP retain the right to challenge the lawfulness of any order issued by the Commission in connection with the assignment, allocation, imputation, pro-forma adjustments to, or disallowances of the revenues and costs associated with DEC's or DEP's wholesale contracts for retail ratemaking and regulatory accounting and reporting purposes on any other grounds, including but not limited to the right outlined in G.S. 62-94(b).

3.9 Other Protections.

(a) DEC, DEP, Piedmont, Duke Energy, another Affiliate, and a Nonpublic Utility Operation shall not assert in any forum – whether judicial, administrative, federal, state, local or otherwise – ~~either on its own initiative or in support of any other entity's assertions that approval by the FERC of market-based rates, transfers of generating facilities, or any matter that involves Affiliates in any way preempts~~ that the Commission's authority to determine the reasonableness or prudence of DEC's, DEP's, or Piedmont's decisions with respect to supply-side resources, demand-side management, or any other aspect of resource adequacy is limited.

(b) No agreement shall be entered into~~, nor shall any filing be made with the FERC,~~ by or on behalf of DEC or DEP, that (i) commits DEC or DEP to, or involves either of them in, joint planning, coordination, dispatch or operation of generation, transmission, or distribution facilities with each other or with one or more other Affiliates, or (ii) otherwise alters DEC's or DEP's obligations with respect to these Regulatory Conditions, absent explicit approval of the Commission.

(c) DEC, DEP, Duke Energy, the other Affiliates, and the Nonpublic Utility Operations shall file notice with the Commission for informational purposes ~~at least 30 days prior to filing with the FERCof~~ at least 15 days prior to filing with the FERC any agreement, tariff, or other document or any proposed amendments, modifications, or supplements to any such document that has the potential to (i) affect DEC's or DEP's retail cost of service for system power supply resources or transmission system; (ii) reduce the Commission's jurisdiction with respect to transmission planning or any other aspect of the Commission's planning authority; (iii) be interpreted as involving DEC or DEP in joint planning, coordination, dispatch, or operation of generation or transmission facilities with one or more Affiliates; or (iv) otherwise have an Effect on DEC's or DEP's Rates or Service. ~~The provisions set forth in Regulatory Condition 13.2 shall apply to an advance notice filed pursuant to this Regulatory Condition; provided, however, that, to the extent the filing with the FERC is not to be made by DEC or DEP, the advance notice procedures shall be for the purpose of a determination by the Commission as to whether the filing is reasonably likely to have an Effect on DEC's or DEP's Rates or Service.~~

(d) Any contract or filing regarding DEC's or DEP's membership in or withdrawal from an RTO or comparable entity must be contingent upon state regulatory approval. This Regulatory Condition does not apply to Piedmont.

(e) DEC, DEP, and Piedmont shall obtain Commission approval before DEBS is sold, transferred, merged with any other entities, has any ownership interest therein changed, or otherwise changed so that a change of control could occur. This requirement does not apply to any movement of DEBS within the Duke Energy holding company system that does not constitute a change of control.

(f) DEC, DEP, and Piedmont may participate in joint comments and other joint filings with Affiliates only when such participation fully complies with both the letter and the spirit of the Regulatory Conditions. Any filing made by DEBS on behalf of DEC, DEP, or Piedmont must clearly identify DEBS as an agent of DEC, DEP, or Piedmont for purposes of making the filing.

(g) Neither DEC, DEP, Piedmont, Duke Energy, another Affiliate, nor a Nonpublic Utility Operation shall make any assertion or argument either on its own initiative or in support of any other entity's assertions in any forum – whether judicial, administrative, federal, state, or otherwise – with respect to any contract, transaction, or other matter in which DEC, DEP, or Piedmont is involved or proposes to be involved or any contract, transaction, or matter involving or proposed to involve Duke Energy, any other Affiliate, or any Nonpublic Utility Operation that may have an Effect on DEC's, DEP's, or Piedmont's Rates or Service, that any of the following actions ~~by the Commission are preempted, in whole or in part, by Federal Law or~~ exceed the Commission's power, authority or jurisdiction under North Carolina law:

(i) reviewing the reasonableness of any Affiliate commitment entered into or proposed to be entered into by DEC, DEP, or Piedmont, or disallowing the costs of, or imputing revenues related to such commitment to, DEC, DEP, or Piedmont;

(ii) exercising its authority over financings or setting rates based on the capital structure, corporate structure, debt costs, or equity costs that it finds to be appropriate for retail ratemaking purposes;

(iii) reviewing the reasonableness of any commitment entered into or proposed to be entered into by DEC, DEP, or Piedmont to transfer an asset;

(iv) mandating, approving, or otherwise regulating a transfer of assets;

(v) scrutinizing and establishing the value of any asset transfers for the purpose of determining the rates for services rendered to DEC's or DEP's Retail Native Load Customers or Piedmont's Customers; or

(vi) exercising any other lawful authority it may have.

Should any other entity so assert, neither DEC, DEP, Piedmont, Duke Energy, other Affiliates, nor the Nonpublic Utility Operations shall support any such assertion and shall, promptly upon learning of such assertion, advise and consult with the Commission and the Public Staff regarding such assertion.

~~(vii) DEC, DEP, Piedmont, Duke Energy, other Affiliates, and the Nonpublic Utility Operations shall (A) bear the full risk of any preemptive effects of Federal Law with respect to any contract, transaction, or commitment entered into or made or proposed to be entered into or made by DEC, DEP, or Piedmont, or which may otherwise affect DEC's, DEP's, or Piedmont's operations, service, or rates and (B) shall take all actions as may be reasonably necessary and appropriate to hold North Carolina ratepayers harmless from rate increases, foregone opportunities for rate decreases or any other adverse effects of such preemption. Such actions include, but are not limited to, filing with and making reasonable efforts to obtain approval from the FERC or other applicable federal entity of such commitments as the Commission deems reasonably necessary to prevent such preemptive effects.~~

(h) DEC, DEP, Piedmont, Duke Energy, other Affiliates, and the Nonpublic Utility Operations shall (A) acknowledge the risk of any possible preemptive effects of Federal Law with respect to any contract, transaction, or commitment entered into or made or proposed to be entered into or made by DEC, DEP, or Piedmont, or which may otherwise affect DEC's, DEP's, or Piedmont's operations, service, or rates and (B) shall take all actions as may be reasonably necessary and appropriate to hold North Carolina ratepayers harmless from rate increases, foregone opportunities for rate decreases or any other adverse effects of such preemption.

3.10 FERC Filings and Orders. In addition to the filing requirements of Commission Rule R8-27 and all other applicable statutes and rules, and to keep the Commission informed of their activities, DEC and DEP shall, on a quarterly basis, file with the Commission the following: (a) a list of all active dockets at the FERC, including a sufficient description to identify the type of proceeding, in which DEC, DEP, Duke Energy, or DEBS is a party, with new information in each quarterly filing tracked; and (b) a list of the periodic reports filed by DEC, DEP, Duke Energy, or DEBS with the FERC, including sufficient information to identify the subject matter of each report and how each report can be accessed. These filings shall be made in Docket Nos. E-7, Sub 1100E, and E-2, Sub 1095E, as appropriate, and updated regularly. In addition, DEC and DEP shall serve on the Public Staff all filed cost-based and market-based wholesale agreements and amendments; all filings related to their Joint Open Access Transmission Tariff;

interconnection agreements and amendments; and any other filings made with the FERC, to the extent these other filings are reasonably likely to have an Effect on DEC's or DEP's Rates or Service. This Regulatory Condition does not apply to Piedmont, as relevant FERC-related information is required to be filed with the Commission in annual gas cost prudence reviews.

SECTION IV
JOINT DISPATCH

The Regulatory Conditions in Section IV do not apply to Piedmont. They are intended to prevent the jurisdiction and authority of the Commission from being preempted as a result of the JDA, to ensure that DEC's and DEP's Retail Native Load Customers receive adequate benefits from the JDA, and to ensure that both joint dispatch costs and the sharing of cost savings can be appropriately audited. The Regulatory Conditions set forth in Section III and the Regulatory Conditions in Section V to the extent they are relevant to Affiliate Contracts also apply to the JDA.

4.1 Conditional Approval and Notification Requirement. DEC and DEP acknowledge that the Commission's approval of the merger between Duke Energy and Progress Energy, and the transfer of dispatch control from DEP to DEC for purposes of implementing the JDA and any successor document is conditioned upon the JDA or successor document never being interpreted as providing for or requiring: (a) a single integrated electric system, (b) a single BAA, control area or transmission system, (c) joint planning or joint development of generation or transmission, (d) DEC or DEP to construct generation or transmission facilities for the benefit of the other, (e) the transfer of any rights to generation or transmission facilities from DEC or DEP to the other, or (f) any equalization of DEC's and DEP's production costs or rates. If, at any time, DEC, DEP or any other Affiliate learns that any of the foregoing interpretations are being considered, in whatever forum, they shall promptly notify and consult with the Commission and the Public Staff regarding appropriate action.

4.2 Advance Notice Required. To the extent that DEC and DEP desire to engage in any of items (a) through (f) listed in Regulatory Condition 4.1, above, DEC and DEP shall file advance notice with the Commission at least 30 days prior to taking any action to amend the JDA or a successor document or to enter into a separate agreement. The provisions of Regulatory Condition 13.2 shall apply to an advance notice filed pursuant to this Regulatory Condition.

4.3 Function in DEC or DEP. The joint dispatch function, as provided in the JDA or in a successor document, shall be performed by employees of either DEC or DEP.

4.4 No Limitation on Obligations. DEC and DEP acknowledge that nothing in the JDA or any successor document is intended to alter DEC's and DEP's public utility obligations under North Carolina law or to provide for joint dispatch in a fashion that is inconsistent with those obligations, including, without limitation, the following: (a) DEC's obligation to plan for and provide least cost electric service to its Retail Native Load Customers and DEP's obligation to plan for and provide least cost electric service to its Retail Native Load Customers; (b) DEC's obligation to serve its Retail Native Load Customers with the lowest cost power it can reasonably generate or purchase from other sources, before making power available for Non-Native Load Sales; and (c) DEP's obligation to serve its Retail Native Load Customers with the lowest cost power it can reasonably generate or purchase from other sources, before making power available for Non-Native Load Sales.

4.5 Protection of Retail Native Load Customers. All joint dispatch and other activities pursuant to the JDA or successor document shall be performed in such a manner as to (a) ensure the reliable fulfillment of DEC's and DEP's respective service obligations to their Retail Native Load Customers, (b) fulfill each utility's obligation to serve its own Retail Native Load Customers with its lowest cost generation; and (c) minimize the total costs incurred by DEC and DEP to fulfill their respective obligations to their Retail Native Load Customers. In no event shall any Non-Native Load Sales be made if, based upon information known, anticipated, or reasonably available at the time a sale is made, any such sale results in higher fuel and fuel-related costs or non-fuel O&M costs, on a replacement cost basis, than would otherwise have been incurred unless the revenues credited from each such sale more than offset the higher costs.

4.6 Treatment of Costs and Savings. DEC's and DEP's respective fuel and fuel-related costs and non-fuel O&M costs, and the treatment of savings for retail ratemaking purposes, shall be calculated as provided in the JDA, unless explicitly changed by order of the Commission.

4.7 Required Records. DEC and DEP shall keep records related to the JDA or any successor document as prescribed by the Commission and in such detail as may be necessary to enable the Commission and the Public Staff to audit both the actual joint dispatch costs and the sharing of cost savings.

4.8 Auditing of Negative Margins. DEC and DEP also shall keep records that provide such detail as may be necessary to enable the Commission and the Public Staff to audit the circumstances that cause any negative margin on a Non-Native Load Sale or a negative transfer payment made pursuant to Section 7.5(a)(ii) of the JDA.

4.9 Protection of Commission's Authority. Neither DEC, DEP, nor any Affiliate shall assert in any forum – whether judicial, administrative, federal, state, local or otherwise – either on its own initiative or in support of any other entity's assertions that any aspect of the JDA or successor document is intended to diminish or alter the jurisdiction or authority of the Commission over DEC or DEP, including, among other things, the jurisdiction and authority of the Commission to do the following: (a) establish the retail rates on a bundled basis for DEC or DEP, (b) to impose regulatory accounting and reporting requirements, (c) impose service quality standards, (d) require DEC and DEP to engage separately in least cost integrated resource planning, and (e) issue certificates of public convenience and necessity for new generating and transmission resources.

4.10 Preventive Action Required. DEC, DEP, Duke Energy, and other Affiliates shall take all necessary actions to prevent the generating facilities owned or controlled by DEC or DEP from being considered by the FERC to be (a) part, or all, of a power pool, (b) sufficiently integrated to be one integrated system, or (c) otherwise fully subject to the FERC's jurisdiction, as the result of DEC's and DEP's participation in the JDA or any successor document.

4.11 Modification and Termination. DEC and DEP shall modify or terminate the JDA if at any time following consummation of the Merger the Commission finds, after notice and opportunity to be heard, that the JDA does not produce overall cost savings for, or is otherwise not in the best interests of, the North Carolina ratepayers of both DEC and DEP.

4.12 Hold Harmless Commitment. DEC and DEP shall take all actions as may be reasonably appropriate and necessary to hold North Carolina retail ratepayers harmless from any adverse rate impacts related to the JDA, including any trapped costs resulting from actions taken or required by the FERC with respect to the JDA.

SECTION V
TREATMENT OF AFFILIATE COSTS AND RATEMAKING

The following Regulatory Conditions are intended to ensure that the costs incurred by DEC, DEP, and Piedmont are properly incurred, accounted for, and directly charged, directly assigned, or allocated to their respective North Carolina retail operations and that only costs that produce benefits for DEC's and DEP's respective Retail Native Load Customers and Piedmont's Customers are included in DEC's, DEP's, and Piedmont's North Carolina cost of service for ratemaking purposes. The procedures set forth in Regulatory Condition 13.2 do not apply to an advance notice filed pursuant to this section.

5.1 Access to Books and Records. In accordance with North Carolina law, the Commission and the Public Staff shall continue to have access to the books and records of DEC, DEP, Piedmont, Duke Energy, other Affiliates, and the Nonpublic Utility Operations.

5.2 Procurement or Provision of Goods and Services by DEC, DEP, or Piedmont from or to Affiliates or Nonpublic Utility Operations. Except as to transactions between and among DEC, DEP, and Piedmont pursuant to filed and approved service agreements and lists of services, and subject to additional provisions set forth in the Code of Conduct, DEC, DEP, and Piedmont shall take the following actions in connection with procuring goods and services for their respective utility operations from Affiliates or Nonpublic Utility Operations and providing goods and services to Affiliates or Nonpublic Utility Operations:

(a) DEC, DEP, and Piedmont each shall seek out and buy all goods and services from the lowest cost qualified provider of comparable goods and services, and shall have the burden of proving that any and all goods and services procured from their Utility Affiliates, Non-Utility Affiliates, and Nonpublic Utility Operations have been procured on terms and conditions comparable to the most favorable terms and conditions reasonably available in the relevant market, which shall include a showing that comparable goods or services could not have been procured at a lower price from qualified non-Affiliate sources or that DEC, DEP, or Piedmont could not have provided the services or goods for itself on the same basis at a lower cost. To this end, no less than every four years DEC, DEP, and Piedmont shall perform comprehensive non-solicitation based assessments at a functional level of the market competitiveness of the costs for goods and services they receive from a Utility Affiliate, DEBS, another Non-Utility Affiliate, and a Nonpublic Utility Operation, including periodic testing of services being provided internally or obtained individually through outside providers. To the extent the Commission approves the procurement or provision of goods and services between or among DEC, DEP, Piedmont, and the Utility Affiliates, those goods and services may be provided at the supplier's Fully Distributed Cost.

(b) To the extent they are allowed to provide such goods and services, DEC, DEP, and Piedmont shall have the burden of proving that all goods and services provided by any one of them to Duke Energy, a Non-Utility Affiliate, any other Affiliate, or a Nonpublic Utility Operation have been provided on the terms and conditions comparable to the most favorable terms and conditions reasonably available in the market, which shall include a showing that such goods or services have been provided at the higher of cost or market price. To this end, no less than every four years DEC, DEP, and Piedmont shall perform comprehensive, non-solicitation based assessments at a functional level of the market competitiveness of the costs for goods and services provided by either of them to a Utility Affiliate, DEBS, another Non-Utility Affiliate, any other Affiliate, and a Nonpublic Utility Operation.

(c) The periodic assessments required by subdivisions (a) and (b) of this subsection may take into consideration qualitative as well as quantitative factors. To the extent that comparable goods or services provided to DEC, DEP or Piedmont, or by DEC, DEP or Piedmont are not commercially available, this Regulatory Condition shall not apply.

5.3 Location of Core Utility Functions.

(a) This Regulatory Condition does not apply to Piedmont.

(b) Core utility functions are those functions related to Electric Services. The employees performing these core utility functions will be DEC or DEP employees and not service company employees of DEBS. Core utility functions do not include services of a governance or corporate type nature that have been traditionally provided by a service company, the specific services listed on the service company agreement services list for DEC and DEP filed with the Commission pursuant to Regulatory Condition 5.4(a), and roles that provide oversight to the enterprise and are not jurisdiction-specific (Excluded Functions).

(c) All core utility functions employees charging 50% or more of their time to DEC and DEP (separately or combined) should be in the payroll company of either DEC or DEP and not on the payroll of an Affiliate such as DEBS. If it is not readily determinable that a particular function is related to the provision of Electric Services or is an Excluded Function, the appropriate payroll company decision will be governed by whether 50% or more of the affected group or individual employee's time is charged to DEC or DEP.

(d) DEC and DEP shall annually review core utility function employees charging more than 50% of their time to DEC and DEP (separately or combined) over a six-month period from January 1 to June 30. If DEC and DEP determine that an employee performing a core utility function is direct charging 50% or more of his or her time to DEC or DEP, that employee should be transferred to DEC or DEP (if not already on the DEC or DEP payroll). Conversely, if a DEC or DEP employee is charging less than 50% of his or her time to DEC or DEP (separately or combined), and the employee is not otherwise charging the larger portion of their time to DEC or DEP, that employee should not be on the payroll of DEC or DEP.

(e) DEC and DEP shall annually file, at least 90 days prior to January 1, a report containing the results of the annual review and advance notice of any transfers from DEC to DEP to another entity based on direct charging results (Employee Payroll Transfer Report). New organizations and reorganizations will be reflected in the Employee Payroll Transfer Reports.

(f) If an employee transfer from DEC or DEP occurs during the middle of the year, and that transfer involves the transfer of a core utility function to the service company, the provisions of Regulatory Condition 10.1 will apply.

(g) DEC and DEP may file a list of employees at the higher levels of management (not including those levels of management that report directly to the Chief Executive Officer for Duke Energy) for their core utility functions that they propose to be DEBS employees in their annual filing.

5.4 Service Agreements and Lists of Services.

(a) DEC, DEP, and Piedmont shall file pursuant to G.S. 62-153 final proposed service agreements that authorize the provision and receipt of non-power goods or services between and among DEC, DEP, Piedmont, their Affiliates or Nonpublic Utility Operations, the list(s) of goods and services that DEC, DEP, and Piedmont each intend to take from DEBS, the list(s) of goods and services DEC, DEP, and Piedmont intend to take from each other and the Utility Affiliates, and the basis for the determination of such list(s) and the elections of such services. All such lists that involve payment of fees or other compensation by DEC, DEP, or Piedmont shall require acceptance and authorization by the Commission, and shall be subject to any other Commission action required or authorized by North Carolina law and the Rules and orders of the Commission.

(b) DEC, DEP, and Piedmont shall take goods and services from an Affiliate only in accordance with the filed service agreements and approved list(s) of services. DEC, DEP, and Piedmont shall file notice with the Commission in Docket Nos. E-7, Sub 1100A, E-2, Sub 1095A, and G-6, Sub 682A, respectively, at least 15 days prior to making any proposed changes to the service agreements or to the lists of services.

5.5 Charges for and Allocations of the Costs of Affiliate Transactions. To the maximum extent practicable, all costs of Affiliate transactions shall be directly charged. When not practicable, such costs shall be assigned in proportion to the direct charges. If such costs are of a nature that direct charging and direct assignment are not practicable, they shall be allocated in accordance with Commission-approved allocation methods. The following additional provisions shall apply:

(a) DEC, DEP, and Piedmont shall keep on file with the Commission a cost allocation manual (CAM) with respect to goods or services provided by DEC, DEP, or Piedmont, any Utility Affiliate, DEBS, any other Non-Utility Affiliate, Duke Energy, any other Affiliates, or any Nonpublic Utility Operation to DEC, DEP, or Piedmont. Piedmont will adopt DEC's and DEP's CAM.

(b) The CAM shall describe how all directly charged, direct assignment, and other costs for each provider of goods and services will be charged between and among DEC, DEP, Piedmont, their Utility Affiliates, Non-Utility Affiliates, Duke Energy, any other Affiliates, and the Nonpublic Utility Operations, and shall include a detailed review of the common costs to be allocated and the allocation factors to be used.

(c) The CAM shall be updated annually, and the revised CAM shall be filed with the Commission no later than March 31 of the year that the CAM is to be in effect. DEC, DEP, and Piedmont shall review the appropriateness of the allocation bases every two years, and the results of such review shall be filed with the Commission. Interim changes shall be made to the CAM, if and when necessary, and shall be filed with the Commission, in accordance with Regulatory Condition 5.6.

(d) No changes shall be made to the procedures for direct charging, direct assigning, or allocating the costs of Affiliate transactions or to the method of accounting for such transactions associated with goods and services (including Shared Services provided by DEBS) provided to or by Duke Energy, other Affiliates, and the Nonpublic Utility Operations until DEC, DEP, or Piedmont has given 15 days' notice to the Commission of the proposed changes, in accordance with Regulatory Condition 5.6.

5.6 Procedures Regarding Interim Changes to the CAM or Lists of Goods and Services for which 15 Days' Notice Is Required. With respect to interim changes to the CAM or changes to lists of goods and services, for which the 15 day notice to the Commission is required, the following procedures shall apply: the Public Staff shall file a response and make a recommendation as to how the Commission should proceed before the end of the notice period. If the Commission has not issued an order within 30 days of the end of the notice period, DEC, DEP, or Piedmont may proceed with the changes but shall be subject to any fully adjudicated Commission order on the matter. The provisions of Regulatory Condition 13.2 do not apply to advance notices filed pursuant to Regulatory Condition 5.5(c) and (d). Such advance notices shall be filed in Docket Nos. E-7, Sub 1100A, E-2, Sub 1095A, and G-9, Sub 682A.

5.7 Annual Reports of Affiliate Transactions. DEC, DEP, and Piedmont shall file annual reports of affiliated transactions with the Commission in a format to be prescribed by the Commission in Docket Nos. E-7, Sub 1100A, E-2, Sub 1095A, and G-9, Sub 682A. The report shall be filed on or before May 30 of each year, for activity through December 31 of the preceding year. DEC, DEP, Piedmont, and other parties may propose changes to the required affiliated transaction reporting requirements and submit them to the Commission for approval, also in Docket Nos. E-7, Sub 1100A, E-2, Sub 1095A, and G-9, Sub 682A.

5.8 Third-party Independent Audits of Affiliate Transactions.

(a) No less often than every two years, a third-party independent audit shall be conducted related to the affiliate transactions undertaken pursuant to Affiliate agreements filed in accordance with Regulatory Condition 5.4 and of DEC's, DEP's, and Piedmont's compliance with all conditions approved by the Commission concerning Affiliate transactions, including the propriety of the transfer pricing of goods and services between or among DEC, DEP, Piedmont, other Affiliates, and all of the Nonpublic Utility Operations.

(i) The first audit shall begin two years from the date of the close of the Merger. It shall include whether DEC's, DEP's, and Piedmont's transactions, services, and other Affiliate dealings pursuant to the regulated utility-to-regulated utility service agreement and any other utility to utility agreements are consistent with all of the conditions related to affiliate dealings and the Code of Conduct and whether DEC, DEP, and Piedmont have operated in accordance with those conditions and Code of Conduct.

(ii) The second audit shall begin two years from the date of the Commission's order on the independent auditor's final report on the first audit or, if no such order is issued, two years from the date of such final report. It shall include whether DEC's, DEP's, and Piedmont's transactions, services, and other Affiliate dealings pursuant to the Service Company Utility Service Agreement and other Affiliate transactions other than transactions undertaken pursuant to regulated utility to regulated utility service agreements are consistent with all of the conditions related to affiliate dealings and the Code of Conduct and whether DEC, DEP, and Piedmont have operated in accordance with those conditions and Code of Conduct.

(iii) Thereafter, independent audits shall occur every two years from the date of the Commission's order on the immediately preceding auditor's final report or, if no such order is issued, two years from the date of such final report. The subject matter of these audits shall alternate between the subject matters for the first and second independent audits. DEC, DEP, and Piedmont may request a change in the frequency of the audit reports in future years, subject to approval by the Commission.

(b) The following further requirements apply:

(i) The independent auditor shall have sufficient access to the books and records of DEC, DEP, Piedmont, Duke Energy, other Affiliates, and all of the Nonpublic Utility Operations to perform the audits.

(ii) For each audit, the Public Staff shall propose one or more independent auditor(s). DEC, DEP, Piedmont, and other parties shall have an opportunity to comment and propose additional auditors. Selection of the independent auditor shall be made by the Commission. Any party proposing an independent auditor shall file such auditor's audit proposal with the Commission.

(iii) The independent auditor shall be supervised in its duties by the Public Staff, and the auditor's reports shall be filed with the Commission.

5.9 Ongoing Review by Commission.

(a) The services rendered by DEC, DEP, and Piedmont to their Affiliates and Nonpublic Utility Operations and the services received by DEC, DEP, or Piedmont from their Affiliates and Nonpublic Utility Operations pursuant to the filed service agreements, the costs and benefits assigned or allocated in connection with such services, and the determination or calculation of the bases and factors utilized to assign or allocate such costs and benefits, as well as DEC's, DEP's, and Piedmont's compliance with the Commission-approved Code of Conduct and all Regulatory Conditions, shall remain subject to ongoing review. These agreements shall be subject to any Commission action required or authorized by North Carolina law and the Rules and orders of the Commission.

(b) The service agreements, the CAM(s) and the assignments and allocations of costs pursuant thereto, the biannual allocation factor reviews required by Regulatory Condition 5.5(c), the list(s) and the goods and services provided pursuant thereto, and any changes to these documents shall be subject to ongoing Commission review, and Commission action if appropriate.

5.10 Future Orders. For the purposes of North Carolina retail accounting, reporting, and ratemaking, the Commission may, after appropriate notice and opportunity to be heard, issue future orders relating to DEC's, DEP's, or Piedmont's cost of service as the Commission may determine are necessary to ensure that DEC's, DEP's, and Piedmont's operations and transactions with their Affiliates and Nonpublic Utility Operations are consistent with the Regulatory Conditions and Code of Conduct, and with any other applicable decisions of the Commission.

5.11 Review by the FERC. Notwithstanding any of the provisions contained in these Regulatory Conditions, to the extent the allocations adopted by the Commission when compared to the allocations adopted by the other State commissions with ratemaking authority as to a Utility Affiliate of DEC, DEP, or Piedmont result in significant trapped costs related to "non-power goods or administrative or management services provided by an associate company organized specifically for the purpose of providing such goods or services to any public utility in the same holding company system," including DEC, DEP, and Piedmont, DEC, DEP, or Piedmont may request pursuant to Section 1275(b) of Subtitle F in Title XII of PUHCA 2005 that the FERC "review and authorize the allocation of the costs for such goods and services to the extent relevant to that associate company." Such review and authorization shall have whatever effect it is determined to have under the law. The quoted language in this Regulatory Condition is taken directly from Section 1275(b) of Subtitle F in Title XII of PUHCA 2005. The terms "associate company" and "holding company system" are defined in Sections 1262(2) and 1262(9), respectively, of Subtitle F in Title XII of PUHCA 2005 and have the same meanings for purposes of this condition.

5.12 Biannual Review of Certain Transactions by Internal Auditors. Transactions between DEC, DEP, or Piedmont and Duke Energy, other Affiliates, or the Nonpublic Utility Operations, transactions between or among DEC, DEP, and Piedmont, and other transactions between or among Affiliates if such transactions are reasonably likely to have a significant Effect on DEC's, DEP's, or Piedmont's Rates or Service, shall be reviewed at least biannually by Duke Energy's internal auditors. To the extent external audits of the transactions are conducted, DEC, DEP, and Piedmont shall make available such audits for review by the Public Staff and the Commission. DEC, DEP, and Piedmont also shall make available for review by the Public Staff and the Commission all workpapers relating to internal audits and all other internal audit workpapers, if any, related to affiliate transactions, and shall not oppose Public Staff and Commission requests to review relevant external audit workpapers. The requirement to make internal audit workpapers available for review is subject to the assertion of the attorney-client privilege by attorneys for DEC, DEP, and Piedmont. Any dispute as to whether the privilege applies in a particular instance shall be resolved by the Commission in accordance with its regulations and North Carolina law, including the rules of the North Carolina State Bar.

5.13 Notice of Service Company and Non-Utility Affiliates FERC Audits. At such time as DEC, DEP, Piedmont, Duke Energy, or DEBS receives notice from the FERC related to an audit of any Affiliate of DEC, DEP, or Piedmont, DEC, DEP, or Piedmont shall promptly file a notice the Commission that such an audit will be commencing. Any initial report of the FERC's audit team shall be provided to the Public Staff, and any final report shall be filed with the Commission in Docket Nos. E-7, Sub 1100E, E-2, Sub 1095E, and G-9, Sub 682E, respectively.

5.14 Acquisition Adjustment. Any acquisition adjustment that results from the Merger shall be excluded from DEC's, DEP's, and Piedmont's utility accounts and treated for regulatory accounting, reporting, and ratemaking purposes so that it does not affect DEC's or DEP's North Carolina retail rates and charges for Electric Services or Piedmont's North Carolina rates and charges for Natural Gas Services.

5.15 Non-Consummation of Merger. If the Merger is not consummated, neither the cost, nor the receipt, of any termination payment between Duke Energy and Piedmont shall be allocated to DEC, DEP, or Piedmont or recorded on their books. DEC's, DEP's, or Piedmont's Customers shall not otherwise bear any direct expenses or costs associated with a failed merger.

5.16 Protection from Commitments to Wholesale Customers.

(a) This Regulatory Condition does not apply to Piedmont.
(b) For North Carolina retail electric cost of service/ratemaking purposes, DEC's and DEP's respective electric system costs shall be assigned or allocated between and among retail and wholesale jurisdictions based on reasonable and appropriate cost

causation principles. For cost of service/ratemaking purposes, North Carolina retail ratepayers shall be held harmless from any cost assignment or allocation of costs resulting from agreements between DEC and the Catawba Joint Owners, and between either DEC or DEP and any of their wholesale customers.

(c) To the extent commitments to DEC's or DEP's wholesale customers relating to the 2012 merger of Duke Energy and Progress Energy are made by or imposed upon DEC or DEP, the effects of which (i) decrease the bulk power revenues that are assigned or allocated to DEC's or DEP's North Carolina retail operations or credited to DEC's or DEP's jurisdictional fuel expenses, (ii) increase DEC's or DEP's North Carolina retail cost of service, or (iii) increase DEC's or DEP's North Carolina retail fuel costs under reasonable cost assignment and allocation practices approved or allowed by the Commission, those effects shall not be recognized for North Carolina retail cost of service or ratemaking purposes.

(d) To the extent that commitments are made by or imposed upon DEC, DEP, Duke Energy, another Affiliate, or a Nonpublic Utility Operation relating to the Merger, either through an offer, a settlement, or as a result of a regulatory order, the effects of which serve to increase the North Carolina retail cost of service or North Carolina retail fuel costs under reasonable cost allocation practices, the effects of these commitments shall not be recognized for North Carolina retail ratemaking purposes.

5.17 Joint Owner-Specific Issues. Assignment or allocation of costs to the North Carolina retail jurisdiction shall not be adversely affected by the manner and amount of recovery of electric system costs from the Catawba Joint Owners as a result of agreements between DEC and the Catawba Joint Owners. This Regulatory Condition does not apply to Piedmont.

5.18 Inclusion of Cost Savings in Future Rate Proceedings. Neither DEC, DEP, Piedmont, Duke Energy, any other Affiliate, nor a Nonpublic Utility Operation shall assert that any interested party is prohibited from seeking the inclusion in future rate proceedings of cost savings that may be realized as a result of any business combination transaction impacting DEC, DEP, and Piedmont.

5.19 Reporting of Costs to Achieve. The North Carolina portion of costs to achieve any business combination transaction savings shall be reflected in DEC's and DEP's North Carolina ES-1 Reports and Piedmont's North Carolina GS-1 Report, as recorded on their books and records under generally accepted accounting principles. DEC, DEP, and Piedmont shall include as a footnote in their ES-1 and GS-1 Reports, as applicable, the Merger-related costs to achieve that were expensed during the relevant period.

5.20 Accounting for Costs to Achieve Related to Historical Events Involving DEP. All costs of Carolina Power and Light Company's merger with North Carolina Natural Gas Company, the Formation of Progress Energy, and Progress Energy's merger with Florida Progress Corporation shall be excluded from DEP's utility accounts, and all direct or indirect corporate cost increases, if any, attributable to those three events shall be excluded from utility costs for all purposes that affect DEP's regulated retail rates and charges. For purposes of this condition, the term "corporate cost increases" means costs in excess of the level DEP would have (a) incurred using prudent business judgment, or (b) had allocated to it, had these transactions not occurred. "Corporate cost increases" also includes any payments made under change-of-control agreements, salary continuation agreements, and other severance- or personnel-type arrangements that are reasonably attributable to these transactions. This Regulatory Condition does not apply to DEC and Piedmont.

5.21 Liabilities of Cinergy Corp. and Florida Progress Corporation.

(a) DEC's and DEP's Retail Native Load Customers and Piedmont's Customers shall be held harmless from all liabilities of Cinergy Corp. and its subsidiaries, including those incurred prior to and after Duke Energy's acquisition of Cinergy Corp. in 2006. These liabilities include, but are not limited to, those associated with the following: (i) manufactured gas plant sites, (ii) asbestos claims, (iii) environmental compliance, (iv) pensions and other employee benefits, (v) decommissioning costs, and (vi) taxes.

(b) DEC's and DEP's Retail Native Load Customers and Piedmont's Customers shall be held harmless from all liabilities of Florida Progress Corporation and its subsidiaries, including those incurred prior to and after Progress Energy's acquisition of Florida Progress Corporation in 2000. These liabilities include, but are not limited to, those associated with the following: (i) any outages at and repairs of Crystal River 3, (ii) manufactured gas plant sites, (iii) asbestos claims, (iv) environmental compliance, (v) pensions and other employee benefits, (vi) decommissioning costs, and (vii) taxes.

(c) DEC's Retail Native Load Customers and Piedmont's Customers shall be held harmless from all current and prospective liabilities of DEP, and DEP's Retail Native Load Customers and Piedmont's Customers shall be held harmless from all current and prospective liabilities of DEC.

5.22 Hold Harmless Commitment. DEC, DEP, Piedmont, Duke Energy, the other Affiliates, and all of the Nonpublic Utility Operations shall take all such actions as may be reasonably necessary and appropriate to hold North Carolina Customers harmless from the effects of the Merger, including rate increases or foregone opportunities for rate decreases, and other effects otherwise adversely impacting Customers.

5.23 Cost of Service Manuals. Within six months after the closing date of the Merger, DEC and DEP shall each file with the Commission revisions to its electric cost of service manual to reflect any changes to the cost of service determination process made necessary by the Merger, any subsequent alterations in the organizational structure of DEC, DEP, Piedmont, Duke Energy, other Affiliates, or the Nonpublic Utility Operations, or other circumstances that necessitate such changes. These filings shall be made in Docket Nos. E-7, Sub 1100A, and E-2, Sub 1095A, respectively. This Regulatory Condition does not apply to Piedmont.

5.24 Direct Charging and Positive Time Reporting for Piedmont. For purposes of distributing the costs of services provided between and among Affiliates, Piedmont will use direct charging and positive time reporting to at least the same extent as DEC and DEP.

5.25 Piedmont Corporate Cost Allocations Among State Jurisdictions. Piedmont will notify the Commission and Public Staff of any plans to modify its corporate cost allocation procedures at least 90 days prior to implementation of the change.

5.26 Allocation of Fully-distributed Costs to Piedmont's Nonpublic Utility Operations. Piedmont shall direct charge or allocate fully distributed costs to its Nonpublic Utility Operations. The fully distributed costs shall include an overhead component for the cost of shared services provided to these non-regulated businesses and equity investments by Piedmont corporate, DEC, DEP, and DEBS employees.

SECTION VI
CODE OF CONDUCT

These Regulatory Conditions include a Code of Conduct in Appendix A. The Code of Conduct governs the relationships, activities and transactions between or among the public utility operations of DEC, DEP, Piedmont, Duke Energy, the Affiliates of DEC, DEP, and Piedmont, and the Nonpublic Utility Operations of DEC, DEP, and Piedmont.

6.1 Obligation to Comply with Code of Conduct. DEC, DEP, Piedmont, Duke Energy, the other Affiliates, and the Nonpublic Utility Operations shall be bound by the terms of the Code of Conduct set forth in Appendix A and as it may subsequently be amended.

SECTION VII
FINANCINGS

The following Regulatory Conditions are intended to ensure (a) that DEC's, DEP's, and Piedmont's capital structures and cost of capital are not adversely affected through their affiliation with Duke Energy, each other, and other Affiliates and (b) that DEC, DEP, and Piedmont have 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.

These conditions do not supersede any orders or directives of the Commission regarding specific securities issuances by DEC, DEP, Piedmont, or Duke Energy. The approval of the Merger by the Commission does not restrict the Commission's right to review, and by order to adjust, DEC's, DEP's, or Piedmont's cost of capital for ratemaking purposes for the effect(s) of the securities-related transactions associated with the Merger.

7.1 Accounting for Equity Investment in Holding Company Subsidiaries. Duke Energy shall maintain its books and records so that any net equity investment in Cinergy Corp. and Progress Energy, their subsidiaries, or their successors, by Duke Energy or any Affiliates can be identified and made available on an ongoing basis. This information shall be provided to the Public Staff upon its request.

7.2 Accounting for Capital Structure Components and Cost Rates. Duke Energy , DEC, DEP, and Piedmont shall keep their respective accounting books and records in a manner that will allow all capital structure components and cost rates of the cost of capital to be identified easily and clearly for each entity on a separate basis. This information shall be provided to the Public Staff upon its request.

7.3 Accounting for Equity Investment in DEC, DEP, and Piedmont. DEC, DEP, and Piedmont shall keep their respective accounting books and records so that the amount of Duke Energy's equity investment in DEC, DEP, and Piedmont can be identified and made available upon request on an ongoing basis. This information shall be provided to the Public Staff upon request.

7.4 Reporting of Capital Contributions. As part of their Commission ES-1 and GS-1 Reports, DEC, DEP, and Piedmont shall include a schedule of any capital contribution(s) received from Duke Energy in the applicable calendar quarter.

7.5 Identification of Long-term Debt Issued by DEC, DEP, or Piedmont. DEC, DEP, and Piedmont shall each identify as clearly as possible long-term debt (of more than one year's duration) that they issue in connection with their regulated utility operations and capital requirements or to replace existing debt.

7.6 Procedures Regarding Proposed Financings.

(a) For all types of financings for which DEC, DEP, or Piedmont (or their subsidiaries) are the issuers of the respective securities, DEC, DEP, or Piedmont (or their subsidiaries) shall request approval from the Commission to the extent required by G.S. 62-160 through G.S. 62-169 and Commission Rule R1-16. Generally, the format of these filings should be consistent with past practices. A "shelf registration" approach (similar to Docket No. E-7, Sub 727) may be requested.

(b) For all types of financings by Duke Energy, other than short-term debt as described in G.S. 62-167, the following shall apply:

(i) On or before January 15 of each year, Duke Energy shall file with the Commission and serve on the Public Staff an advance confidential plan of all securities issuances that it anticipates to occur during that calendar year. The annual confidential plan shall include a description of all financings that Duke Energy reasonably believes may occur during the applicable calendar year. A description for each financing shall include the best estimates of the following: type of security; estimate of cost rate (e.g., interest rate for debt); amount of proceeds; brief description of the purpose/reason for issue; and amount of proceeds, if any, that may flow to DEC, DEP, or Piedmont.

(ii) If at any time material changes to the financing plans included in the filed plan appear likely, Duke Energy shall file a revised 30-day advance confidential plan that specifically addresses such changes with the Commission and serve such notice on the Public Staff.

(iii) At the time of the confidential plan filings identified above, Duke Energy shall also file a non-confidential notice that states that a confidential plan has been filed in compliance with this Regulatory Condition 7.6(b).

(iv) Duke Energy may proceed with equity issuances upon the filing of the confidential plan. However, actual debt issuances shall not occur until 30 days after the advance confidential plan or revised plans are filed. In the event it is not feasible for Duke Energy to file a revised advance confidential plan for a material change 30 days in advance, such plan shall be filed by a date that allows adequate time for review or a debt issuance shall be delayed to allow such review. Prior to the Commission's action on the confidential plan for the year in which the plan is filed, Duke Energy may issue securities authorized under the previous year's plan to the extent such securities were not issued during the previous year.

(v) Within 15 days after the filing of an advance confidential plan or revised plan, the Public Staff shall file a confidential report with the Commission with respect to whether any debt issuances require approval pursuant to G.S. 62-160 through G.S. 62-169 and Commission Rule R1-16 and shall recommend that the Commission issue an order deciding how to proceed. Duke Energy shall have seven days in which to respond to the report. If the Commission determines that any debt issuance requires approval, the Commission shall issue an order requiring the filing of an application and no such issuance shall occur until the Commission approves the application. If the Commission determines that no debt issuance requires approval, the Commission shall issue an order so ruling. At the end of the notice period, Duke Energy may proceed with the debt issuance, but shall be subject to any fully adjudicated Commission order on the matter; provided, however, that nothing herein shall affect the applicability of G.S. 62-170 or other similar provision to such securities or obligations.

(vi) On or before April 15 of each year, Duke Energy shall file with the Commission a report on all financings that were executed for the previous calendar year. The actual reports should include the same information as required above for the advance plans plus the actual issuance costs.

(c) If a filing with the Securities and Exchange Commission or other federal agency will be made in connection with a securities issuance, the notice shall describe such filing(s) and indicate the approximate date on which it would occur.

(d) Securities issuances or financings that are associated with a merger, acquisition, or other business combination shall be filed in conjunction with the information requirements and deadlines stated in Regulatory Conditions 9.1 and 9.2, and this Condition 7.6 shall not apply to such securities issuances or financings.

7.7 Money Pool Agreement. Subject to the limitations imposed in Regulatory Condition 8.5, DEC, DEP, and Piedmont may borrow through Duke Energy's "Utility Money Pool Agreement" (Utility MPA), provided as follows: (a) participation in the Utility MPA is limited to the parties to the Utility MPA filed with the Commission on December 1, 2011, in Docket Nos. E-7, Sub 986A, and E-2, Sub 998A, plus Piedmont and with the exception of the Progress Energy Service Company; and (b) the Utility MPA continues to provide that no loans through the Utility MPA will be made to, and no borrowings through the Utility MPA will be made by, Duke Energy, Progress Energy, and Cinergy Corp.

7.8 Borrowing Arrangements. Subject to the limitations imposed in Regulatory Condition 8.5, DEC, DEP, and Piedmont may borrow short-term funds through one or more joint external debt or credit arrangements (a Credit Facility), provided that the following conditions are met:

(a) No borrowing by DEC, DEP, or Piedmont under a Credit Facility shall exceed one year in duration, absent Commission approval;
(b) No Credit Facility shall include, as a borrower, any party other than Duke Energy, DEC, DEP, Duke Indiana, Duke Kentucky, DEF, Duke Ohio, and Piedmont; and
(c) DEC's, DEP's, and Piedmont's participation in any Credit Facility shall in no way cause either of them to guarantee, assume liability for, or provide collateral for any debt or credit other than its own.

7.9 Long-Term Debt Fund Restrictions. DEC, DEP, and Piedmont shall acquire their respective long-term debt funds through the financial markets, and shall neither borrow from, nor lend to, on a long-term basis, Duke Energy or any of the other Affiliates. To the extent that either DEC, DEP, or Piedmont borrows on short-term or long-term bases in the financial markets and is able to obtain a debt rating, its debt shall be rated under its own name.

SECTION VIII
CORPORATE GOVERNANCE/RING FENCING

The following Regulatory Conditions are intended to ensure the continued viability of DEC, DEP, and Piedmont and to insulate and protect DEC, DEP, and their Retail Native Load Customers and Piedmont and its Customers from the business and financial risks of Duke Energy and the Affiliates within the Duke Energy holding company system, including the protection of utility assets from liabilities of Affiliates.

8.1 Investment Grade Debt Rating. DEC, DEP, and Piedmont shall manage their respective businesses so as to maintain an investment grade debt rating on all of their rated debt issuances with all of the debt rating agencies on all of their rated debt issuances. If DEC's, DEP's, or Piedmont's debt rating falls to the lowest level still considered investment grade at the time, DEC, DEP, or Piedmont shall file written notice to the Commission and the Public Staff within five (5) days of such change and an explanation as to why the downgrade occurred. Within 45 days of such notice, DEC, DEP, or Piedmont shall provide the Commission and the Public Staff with a specific plan for maintaining and improving its debt rating. The Commission, after notice and hearing, may then take whatever action it deems necessary consistent with North Carolina law to protect the interests of DEC's or DEP's Retail Native Load Customers and Piedmont's Customers in the continuation of adequate and reliable service at just and reasonable rates.

8.2 Protection Against Debt Downgrade. To the extent the cost rates of any of DEC's, DEP's, or Piedmont's long-term debt (more than one year) or short-term debt (one year or less) are or have been adversely affected through a ratings downgrade attributable to the Merger, a replacement cost rate to remove the effect shall be used for all purposes affecting any of DEC's North Carolina retail rates and charges, DEP's North Carolina retail rates and charges, and Piedmont's North Carolina rates and charges. This replacement cost rate shall be applicable to all financings, refundings, and refinancings taking place following the change in ratings. This procedure shall be effective through DEC's, DEP's and Piedmont's next respective general rate cases. As part of DEC's, DEP's and Piedmont's next respective general rate cases, any future procedure relating to a replacement cost calculation will be determined. This Regulatory Condition does not indicate a preference for a specific debt rating or preferred stock rating for DEC, DEP, or Piedmont on current or prospective bases.

8.3 Distributions from DEC, DEP, and Piedmont to Holding Company. DEC, DEP, and Piedmont shall limit cumulative distributions paid to Duke Energy subsequent to the Merger to (a) the amount of Retained Earnings on the day prior to the closure of the Merger, plus (b) any future earnings recorded by DEC, DEP, and Piedmont subsequent to the Merger.

8.4 Debt Ratio Restrictions. To the extent any of Duke Energy's external debt or credit arrangements contain covenants restricting the ratio of debt to total capitalization on a consolidated basis to a maximum percentage of debt, Duke Energy shall ensure that the capital structures of both DEC, DEP, and Piedmont individually meet those restrictions.

8.5 Limitation on Continued Participation in Utility Money Pool Agreement and Other Joint Debt and Credit Arrangements with Affiliates. DEC, DEP, and Piedmont may participate in the Utility MPA and any other authorized joint debt or credit arrangement as provided in Regulatory Conditions 7.7 and 7.8 only to the extent such participation is beneficial to DEC's and DEP's respective Retail Native Load Customers and Piedmont's Customers and does not negatively affect DEC's, DEP's, or Piedmont's ability to continue to provide adequate and reliable service at just and reasonable rates.

8.6 Notice of Level of Non-Utility Investment by Holding Company System. In order to enable the Commission to determine whether the cumulative investment by Duke Energy in assets, ventures, or entities other than regulated utilities is reasonably likely to have an Effect on DEC's, DEP's, or Piedmont's Rates or Service so as to warrant Commission action (pursuant to Regulatory Condition 8.8 or other applicable authority) to protect DEC's or DEP's Retail Native Load Customers or Piedmont's Customers, Duke Energy shall notify the Commission within 90 days following the end of any fiscal year for which Duke Energy reports to the Securities and Exchange Commission assets in its operations other than regulated utilities that are in excess of 22% of its consolidated total assets. The following procedures shall apply to such a notice:

(a) Any interested party may file comments within 45 days of the filing of Duke Energy's notice.

(b) If timely comments are filed, the Public Staff shall place the matter on a Commission Staff Conference agenda as soon as possible, but in no event later than 15 days after the comments are filed, and shall make a recommendation as to how the Commission should proceed. If the Commission determines that the percentage of total assets invested in Duke Energy's its operations other than regulated utilities is reasonably likely to have an Effect on DEC's, DEP's, or Piedmont's Rates or Service so as to warrant action by the Commission to protect DEC's and DEP's Retail Native Load Customers and Piedmont's Customers, the Commission shall issue an order setting the matter for further consideration. If the Commission determines that the percentage threshold being exceeded does not warrant action by the Commission, the Commission shall issue an order so ruling.

8.7 Notice by Holding Company of Certain Investments. Duke Energy shall file a notice with the Commission subsequent to Board approval and as soon as practicable following any public announcement of any investment in a regulated utility or a non-regulated business that represents five (5) percent or more of Duke Energy's book capitalization.

8.8 Ongoing Review of Effect of Holding Company Structure. The operation of DEC, DEP, and Piedmont under a holding company structure shall continue to be subject to Commission review. To the extent the Commission has authority under North Carolina law, it may order modifications to the structure or operations of Duke Energy, DEBS, another Affiliate, or a Nonpublic Utility Operation, and may take whatever action it deems necessary in the interest of Retail Native Load Customers and Piedmont's Customers to protect the economic viability of DEC, DEP, and Piedmont, including the protection of DEC's, DEP's, and Piedmont's public utility assets from liabilities of Affiliates.

8.9 Investment by DEC, DEP, or Piedmont in Non-regulated Utility Assets and Non-utility Business Ventures. Neither DEC, DEP, nor Piedmont shall invest in a non-regulated utility asset or any non-utility business venture exceeding $50 million in purchase price or gross book value to DEC, DEP, or Piedmont unless it provides 30 days' advance notice. Regulatory Condition 13.2 shall apply to an advance notice filed pursuant to this Regulatory Condition. Purchases of assets, including land that will be held with a definite plan for future use in providing Electric Services in DEC's or DEP's franchise area or Natural Gas Services in Piedmont's franchise area, shall be excluded from this advance notice requirement.

8.10 Investment by Holding Company in Exempt Wholesale Generators. By April 15 of each year, Duke Energy shall provide to the Commission and the Public Staff a report summarizing Duke Energy's investment in exempt wholesale generators (EWGs) and foreign utility companies (FUCOs) in relation to its level of consolidated retained earnings and consolidated total capitalization at the end of the preceding year. Exempt wholesale generator and foreign utility company are defined in Section 1262(6) of Subtitle F in Title XII of PUHCA 2005 and have the same meanings for purposes of this condition.

8.11 Notice by DEC, DEP, or Piedmont of Default or Bankruptcy of Affiliate. If an Affiliate of DEC, DEP, or Piedmont experiences a default on an obligation that is material to Duke Energy or files for bankruptcy, and such bankruptcy is material to Duke Energy, DEC, DEP, or Piedmont shall notify the Commission in advance, if possible, or as soon as possible, but not later than ten days from such event.

8.12 Annual Report on Corporate Governance. No later than March 31 of each year, DEC, DEP, and Piedmont shall file a report including the following:

(a) A complete, detailed organizational chart (i) identifying DEC, DEP, Piedmont, and each Duke Energy financial reporting segment, and (ii) stating the business purpose of each Duke Energy financial reporting segment. Changes from the report for the immediately preceding year shall be summarized at the beginning of the report.

(b) A list of all Duke Energy financial reporting segment that are considered to constitute non-regulated investments and a statement of each segment's total capitalization and the percentage it represents of Duke Energy's non-regulated investments and total investments. Changes from the report for the immediately preceding year shall be summarized at the beginning of the report.

(c) An assessment of the risks that each unregulated Duke Energy financial reporting segment could pose to DEC, DEP, or Piedmont based upon current business activities of those affiliates and any contemplated significant changes to those activities.

(d) A description of DEC's, DEP's, Piedmont's and each significant Affiliate's actual capital structure. In addition, describe Duke Energy's, DEC's, DEP's, and Piedmont's respective capital structures and plans for achieving such goals.

(e) A list of all protective measures (other than those provided for by the Regulatory Conditions adopted in Docket Nos. E-7, Sub 1100, E-2, Sub 1095, and G-9, Sub 682) in effect between DEC, DEP, Piedmont, and any of their Affiliates, and a description of the goal of each measure and how it achieves that goal, such as mitigation of DEC's, DEP's, and Piedmont's exposure in the event of a bankruptcy proceeding involving any Affiliate(s).

(f) A list of corporate executive officers and other key personnel that are shared between DEC, DEP, Piedmont, and any Affiliate, along with a description of each person's position(s) with, and duties and responsibilities to each entity.

(g) A calculation of Duke Energy's total book and market capitalization as of December 31 of the preceding year for common equity, preferred stock, and debt.

SECTION IX
FUTURE MERGERS AND ACQUISITIONS

The following Regulatory Conditions are intended to ensure that the Commission receives sufficient notice to exercise its lawful authority over proposed mergers, acquisitions, and other business combinations involving Duke Energy, DEC, DEP, Piedmont, other Affiliates, or the Nonpublic Utility Operations. The advance notice provisions set forth in Regulatory Condition 13.2 do not apply to these conditions.

9.1 Mergers and Acquisitions by or Affecting DEC, DEP, or Piedmont. For any proposed merger, acquisition, or other business combination by DEC, DEP, or Piedmont that would have an Effect on DEC's, DEP's, or Piedmont's Rates or Service, DEC, DEP, or Piedmont shall file in a new Sub docket an application for approval pursuant to G S. 62-111(a) at least 180 days before the proposed closing date for such merger, acquisition, or other business combination.

9.2 Mergers and Acquisitions Believed Not to Have an Effect on DEC's, DEP's, or Piedmont's Rates or Service. For any proposed merger, acquisition, or other business combination that is believed not to have an Effect on DEC's, DEP's, or Piedmont's Rates or Service, but which involves Duke Energy, other Affiliates, or the Nonpublic Utility Operations and which has a transaction value exceeding $1.5 billion, the following shall apply:

(a) Advance notification shall be filed with the Commission in a new Sub docket by the merging entities at least 90 days prior to the proposed closing date for such proposed merger, acquisition or other business combination. The advance notification is intended to provide the Commission an opportunity to determine whether the proposed merger, acquisition, or other business combination is reasonably likely to affect DEC, DEP, or Piedmont so as to require approval pursuant to G S. 62-111(a). The notification shall contain sufficient information to enable the Commission to make such a determination. If the Commission determines that such approval is required, the 180-day advance filing requirement in Regulatory Condition 9.1 shall not apply.

(b) Any interested party may file comments within 45 days of the filing of the advance notification.

(c) If timely comments are filed, the Public Staff shall place the matter on a Commission Staff Conference agenda as soon as possible, but in no event later than 15 days after the comments are filed, and shall recommend that the Commission issue an order deciding how to proceed. If the Commission determines that the merger, acquisition, or other business combination requires approval pursuant to G.S. 62-111(a), the Commission shall issue an order requiring the filing of an application, and no closing can occur until and unless the Commission approves the proposed merger, acquisition, or business combination. If the Commission determines that the merger, acquisition, or other business combination does not require approval pursuant to G.S. 62-111(a), the Commission shall issue an order so ruling. At the end of the notice period, if no order has been issued, Duke Energy, any other Affiliate, or the Nonpublic Utility Operation may proceed with the merger, acquisition, or other business combination but shall be subject to any fully-adjudicated Commission order on the matter.

SECTION X
STRUCTURE/ORGANIZATION

The following Regulatory Conditions are intended to ensure that the Commission receives adequate notice of, and opportunity to review and take such lawful action as is necessary and appropriate with respect to, changes to the structure and organization of Duke Energy, DEC, DEP, Piedmont, and other Affiliates, and Nonpublic Utility operations as they may affect Customers.

10.1 Transfer of Services, Functions, Departments, Rights, Assets, or Liabilities. DEC, DEP, and Piedmont shall file notice with the Commission 30 days prior to the initial transfer or any subsequent transfer of any services, functions, departments, rights, obligations, assets, or liabilities from DEC, DEP, or Piedmont to DEBS that (a) involves services, functions, departments, rights, obligations, assets, or liabilities other than those of a governance or corporate type nature that traditionally have been provided by a service company or (b) potentially would have a significant effect on DEC's, DEP's, or Piedmont's public utility operations. The provisions of Regulatory Condition 13.2 apply to an advance notice filed pursuant to this Regulatory Condition.

10.2 Notice and Consultation with Public Staff Regarding Proposed Structural and Organizational Changes. Upon request, DEC, DEP, and Piedmont shall meet and consult with, and provide requested relevant data to, the Public Staff regarding plans for significant changes in DEC's, DEP's, Piedmont's or Duke Energy's organization, structure (including RTO developments), and activities; the expected or potential impact of such changes on Customer rates, operations and service; and proposals for assuring that such plans do not adversely affect DEC's or DEP's Retail Native Load Customers or Piedmont's Customers. To the extent that proposed significant changes are planned for the organization, structure, or activities of an Affiliate or Nonpublic Utility Operation and such proposed changes are likely to have an adverse impact on DEC's, DEP's, or Piedmont's Customers, then DEC's, DEP's, and Piedmont's plans and proposals for assuring that those plans do not adversely affect their Customers must be included in these meetings. DEC, DEP, and Piedmont shall inform the Public Staff promptly of any such events and changes.

SECTION XI
SERVICE QUALITY

The following Regulatory Conditions are intended to ensure that DEC, DEP, and Piedmont continue to implement and further their commitment to providing superior public utility service by meeting recognized service quality indices and implementing the best practices of each other and their Utility Affiliates, to the extent reasonably practicable.

11.1 Overall Service Quality. Upon consummation of the Merger, DEC, DEP, and Piedmont each shall continue their commitment to providing superior public utility service and shall maintain the overall reliability of Electric Services and Natural Gas Services at levels no less than the overall levels it has achieved in the past decade.

11.2 Best Practices. DEC, DEP, and Piedmont shall make every reasonable effort to incorporate each other's best practices into its own practices to the extent practicable.

11.3 Quarterly Reliability Reports. DEC and DEP shall each provide quarterly service reliability reports to the Public Staff on the following measures: System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI).

11.4 Notice of NERC Audit. This Regulatory Condition does not apply to Piedmont. At such time as either DEC or DEP receives notice that the North American Electric Reliability Corporation (NERC) or the SERC Reliability Corporation will be conducting a non-routine compliance audit with respect to DEC's or DEP's compliance with mandatory reliability standards, DEC or DEP shall notify the Public Staff.

11.5 Right-of-Way Maintenance Expenditures (DEC and DEP). DEC and DEP shall budget and expend sufficient funds to trim and maintain their lower voltage line rights-of-way and their distribution rights-of-way in a manner consistent with their internal right-of-way clearance practices and Commission Rule R8-26. In addition, DEC and DEP shall track annually, on a major category basis, departmental or division budget requests, approved budgets and actual expenditures for right-of-way maintenance.

11.6 Right-of-Way Maintenance Expenditures (Piedmont). Piedmont shall budget and expend sufficient funds to maintain its pipeline rights-of-way so as to allow ready access by personnel and vehicles for the purpose of responding to pipeline damage, conducting leak and corrosion surveys, performing maintenance activities, and ensuring system integrity, safety, and reliability.

11.7 Right-of-Way Clearance Practices (DEC and DEP). DEC and DEP shall each provide a copy of their internal right-of-way clearance practices to the Public Staff, and shall promptly notify the Public Staff of any significant changes or modifications to the practices or maintenance schedules.

11.8 Right-of-Way Clearance Practices (Piedmont). Piedmont shall provide a copy of its Operating and Maintenance Manual to the Public Staff and shall promptly notify the Public Staff in writing of any substantive changes to Section 9, "Right-of-Way Management Program."

11.9 Meetings with Public Staff.

(a) DEC, DEP, and Piedmont shall each meet annually with the Public Staff to discuss service quality initiatives and results, including (i) ways to monitor and improve service quality, (ii) right-of-way maintenance practices, budgets, and actual expenditures, and (iii) plans that could have an effect on customer service, such as changes to call center operations.

(b) DEC, DEP, and Piedmont shall each meet with the Public Staff at least annually to discuss potential new tariffs, programs, and services that enable its customers to appropriately manage their energy bills based on the varied needs of their customers.

11.10 Customer Access to Service Representatives and Other Services. DEC, DEP, and Piedmont shall continue to have knowledgeable and experienced customer service representatives available 24 hours a day to respond to service outage calls and during normal business hours to handle all types of customer inquiries. DEC, DEP, and Piedmont shall also maintain up-to-date and user-friendly online services and automated telephone service

24 hours a day to perform routine customer interactions and to provide general billing and customer information.

11.11 Customer Surveys. DEC, DEP, and Piedmont shall continue to survey their customers regarding their satisfaction with public utility service and shall incorporate this information into their processes, programs, and services.

SECTION XII
TAX MATTERS

The following Regulatory Conditions are intended to ensure that DEC's, DEP's, and Piedmont's North Carolina Customers do not bear any additional tax costs as a result of the Merger and receive an appropriate share of any tax benefits associated with the service company Affiliates.

12.1 Costs under Tax Sharing Agreements. Under any tax sharing agreement, DEC, DEP, and Piedmont shall not seek to recover from North Carolina Customers any tax costs that exceed DEC's, DEP's, or Piedmont's tax liability calculated as if it were a stand-alone, taxable entity for tax purposes.

12.2 Tax Benefits Associated with Service Companies. The appropriate portion of any income tax benefits associated with DEBS shall accrue to the North Carolina retail operations of DEC, DEP, and Piedmont, respectively, for regulatory accounting, reporting, and ratemaking purposes.

SECTION XIII
PROCEDURES

The following Regulatory Conditions are intended to apply to all filings made pursuant to these Regulatory Conditions unless otherwise expressly provided by, Commission order, rule, or statute.

13.1 Filings that Do Not Involve Advance Notice. Regulatory Condition filings that are not subject to Regulatory Condition 13.2 shall be made in sub dockets of Docket Nos. E-7, Sub 1100, E-2, Sub 1095, and G-9, Sub 682, as follows:

(a) Filings related to affiliate matters required by Regulatory Conditions 5.4, 5.5, 5.6, 5.7, and 5.23 and the filing permitted by Regulatory Condition 5.3 shall be made by DEC, DEP, and Piedmont in Subs 1100A, 1095A, and 682A, respectively;

(b) Filings related to financings required by Regulatory Condition 7.6, and the filings required by Regulatory Conditions 8.6, 8.7, 8.10, 8.11 and 8.12 shall be made by DEC, DEP, and Piedmont in Subs 1100B, 1095B, and 682B, respectively;

(c) Files related to compliance as required by Regulatory Conditions~~ 3.1(d) and~~ 14.4 and filings required by Sections III.A.2(k), III.A.3(e), (f), and (g), III.D.5, and III.D.8 of the Code of Conduct shall be made by DEC, DEP, and Piedmont in Subs 1100C, 1095C, and 682C, respectively;

(d) Filings related to the independent audits required by Regulatory Condition 5.8 shall be made in Subs 1100D, 1095D, and 682D, respectively; and

(e) Filings related to orders and filings with the FERC, as required by Regulatory Condition 3.1(d), 3.10 and 5.13 shall be made by DEC, DEP, and Piedmont in Subs 1100E, 1095E, and 682E, respectively.

13.2 Advance Notice Filings. Advance notices filed pursuant to Regulatory Conditions ~~3.1(e)~~, 3.3(b), ~~3.7(e), 3.9(e),~~ 4.2, ~~5.3,~~ 8.9, and 10.1 shall be assigned a new, separate Sub docket. Such a filing shall identify the condition and notice period involved and state whether other regulatory approvals are required and shall be in the format of a pleading, with a caption, a title, allegations of the activities to be undertaken, and a verification. Advance notices may be filed under seal if necessary. The following additional procedures apply:

(a) Advance notices of activities to be undertaken shall not be filed until sufficient details have been decided upon to allow for meaningful discovery as to the proposed activities.

(b) The Chief Clerk shall distribute a copy of advance notice filings to each Commissioner and to appropriate members of the Commission Staff and Public Staff.

(c) DEC, DEC, or Piedmont shall serve such advance notices on each party to Docket Nos. E-7, Sub 1100, E-2, Sub 1095, and G-9, Sub 682, respectively, that has filed a request to receive them with the Commission within 30 days of the issuance of an order approving the Merger in this docket. These parties may participate in the advance notice proceedings without petitioning to intervene. Other interested persons shall be required to follow the Commission's usual intervention procedures.

(d) To effectuate this Regulatory Condition, DEC, DEP, or Piedmont shall serve pertinent information on all parties at the time it serves the advance notice. During the advance notice period, a free exchange of information is encouraged, and parties may request additional relevant information. If DEC, DEP, or Piedmont objects to a discovery request, DEC, DEP, or Piedmont and the requesting party shall try to resolve the matter. If the parties are unable to resolve the matter, DEC, DEP, or Piedmont may file a motion for a protective order with the Commission.

(e) The Public Staff shall investigate and file a response with the Commission no later than 15 days before the notice period expires. Any other interested party may also file a response or objection within 15 days before the notice period expires. DEC, DEP, or Piedmont may file a reply to the response(s).

(f) The basis for any objection to the activities to be undertaken shall be stated with specificity. The objection shall allege grounds for a hearing, if such is desired.

(g) If neither the Public Staff nor any other party files an objection to the activities within 15 days before the notice period expires, no Commission order shall be issued, and the Sub docket in which the advance notice was filed may be closed.

(h) If the Public Staff or any other party files a timely objection to the activities to be undertaken by DEC, DEP, or Piedmont, the Public Staff shall place the matter on a Commission Staff Conference agenda as soon as possible, but in no event later than two weeks after the objection is filed, and shall recommend that the Commission issue an order deciding how to proceed as to the objection. The Commission reserves the right to extend an advance notice period by order should the Commission need additional time to deliberate or investigate any issue. At the end of the notice period, if no objection has been filed by the Public Staff and no order, whether procedural or substantive, has been issued, DEC, DEP, Piedmont, Duke Energy, any other Affiliate, or the Nonpublic Utility Operation may execute the proposed agreement, proceed with the activity to be undertaken, or both, but shall be subject to any fully-adjudicated Commission order on the matter.

(i) If the Commission schedules a hearing on an objection, the party filing the objection shall bear the burden of proof at the hearing.

(j) The precedential effect of advance notice proceedings, like most issues of res judicata, will be decided on a fact-specific basis.

(k) If some other Commission filing or Commission approval is required by statute, notice pursuant to a Regulatory Condition alone does not satisfy the statutory requirement.

SECTION XIV
COMPLIANCE WITH CONDITIONS AND CODE OF CONDUCT

The following Regulatory Conditions are intended to ensure that Duke Energy, DEC, DEP, Piedmont, and all other Affiliates establish and maintain the structures and processes necessary to fulfill the commitments expressed in all of the Regulatory Conditions and the Code of Conduct in a timely, consistent, and effective manner.

14.1 Ensuring Compliance with Regulatory Conditions and Code of Conduct. Duke Energy, DEC, DEP, Piedmont, and all other Affiliates shall devote sufficient resources into the creation, monitoring, and ongoing improvement of effective internal compliance programs to ensure compliance with all Regulatory Conditions and the DEC/DEP/Piedmont Code of Conduct, and shall take a proactive approach toward correcting any violations and reporting them to the Commission. This effort shall include the implementation of systems and protocols for monitoring, identifying, and correcting possible violations, a management culture that encourages compliance among all personnel, and the tools and training sufficient to enable employees to comply with Commission requirements.

14.2 Designation of Chief Compliance Officer. DEC, DEP, and Piedmont shall designate a chief compliance officer who will be responsible for compliance with the Regulatory Conditions and Code of Conduct. This person's name and contact information must be posted on DEC's, DEP's, and Piedmont's Internet Websites.

14.3 Annual Training. DEC, DEP, and Piedmont shall provide annual training on the requirements and standards contained within the Regulatory Conditions and Code of Conduct to all of their employees (including service company employees) whose duties in any way may be affected by such requirements and standards. New employees must receive such training within the first 60 days of their employment. Each employee who has taken the training must certify electronically or in writing that s/he has completed the training.

14.4 Report of Violations. If DEC, DEP, or Piedmont discover that a violation of their requirements or standards contained within the Regulatory Conditions and Code of Conduct has occurred then DEC, DEP, or Piedmont shall file a statement with the Commission in Docket Nos. E-7, Sub 1100C, E-2, Sub 1095C, and G-9, Sub 682C, respectively, describing the circumstances leading to that violation of DEC's, DEP's, or Piedmont's requirements or standards, as contained within the Regulatory Conditions and Code of Conduct, and the mitigating and other steps taken to address the current or any future potential violation.

SECTION XV
PROCEDURES FOR DETERMINING LONG-TERM SOURCES OF PIPELINE CAPACITY AND SUPPLY

The following Regulatory Conditions are intended to ensure the continued practices of DEC, DEP, and Piedmont for determining long-term sources of pipeline capacity and supply.

15.1 Cost-benefit Analysis. The appropriate source(s) for the interstate pipeline capacity and supply shall be determined by DEC and DEP on the basis of the benefits and costs of such source(s) specific to their respective electric customers. The appropriate source(s) for the interstate pipeline capacity and supply shall be determined by Piedmont on the basis of the specific benefits and costs of such source(s) specific to its natural gas customers, including electric power generating customers.

15.2 Ownership and Control of Contracts. Piedmont shall retain title, ownership, and management of all gas contracts necessary to ensure the provision of reliable Natural Gas Services consistent with Piedmont's best cost gas and capacity procurement methodology.

CODE OF CONDUCT
GOVERNING THE RELATIONSHIPS, ACTIVITIES, AND TRANSACTIONS BETWEEN AND AMONG THE PUBLIC UTILITY OPERATIONS OF DEC, THE PUBLIC UTILITY OPERATIONS OF DEP, THE PUBLIC UTILITY OPERATIONS OF PIEDMONT, DUKE ENERGY CORPORATION, OTHER AFFILIATES, AND THE NONPUBLIC UTILITY OPERATIONS OF DEC, DEP, AND PIEDMONT

I. DEFINITIONS

For the purposes of this Code of Conduct, the terms listed below shall have the following definitions:

Affiliate: Duke Energy and any business entity of which ten percent (10%) or more is owned or controlled, directly or indirectly, by Duke Energy. For purposes of this Code of Conduct, Duke Energy and any business entity controlled by it are considered to be Affiliates of DEC, DEP, and Piedmont, and DEC, DEP, and Piedmont are considered to be Affiliates of each other.

Commission: The North Carolina Utilities Commission.

Confidential Systems Operation Information or CSOI: Nonpublic information that pertains to Electric Services provided by DEC or DEP, including but not limited to information concerning electric generation, transmission, distribution, or sales, and nonpublic information that pertains to Natural Gas Services provided by Piedmont, including but not limited to information concerning transportation, storage, distribution, gas supply, or other similar information.

Customer: Any retail electric customer of DEC or DEP in North Carolina and any Commission-regulated natural gas sales or natural gas transportation customer of Piedmont located in North Carolina.

Customer Information: Non-public information or data specific to a Customer or a group of Customers, including, but not limited to, electricity consumption, natural gas consumption, load profile, billing history, or credit history that is or has been obtained or compiled by DEC, DEP, or Piedmont in connection with the supplying of Electric Services or Natural Gas Services to that Customer or group of Customers.

DEBS: Duke Energy Business Services, LLC, and its successors, which is a service company Affiliate that provides Shared Services to DEC, DEP, Piedmont, Duke Energy, other Affiliates, or the Nonpublic Utility Operations of DEC, DEP, or Piedmont, singly or in any combination.

DEC: Duke Energy Carolinas, LLC, the business entity, wholly owned by Duke Energy, that holds the franchise granted by the Commission to provide Electric Services within DEC's North Carolina service territory and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

DEP: Duke Energy Progress. LLC, the business entity, wholly owned by Duke Energy, that holds the franchises granted by the Commission to provide Electric Services within the DEP's North Carolina service territory and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

Duke Energy: Duke Energy Corporation, which is the current holding company parent of DEC, DEP, and Piedmont, and any successor company.

Electric Services: Commission-regulated electric power generation, transmission, distribution, delivery, and sales, and other related services, including, but not limited to, administration of Customer accounts and rate schedules, metering, billing, standby service, backups, and changeovers of service to other suppliers.

Fuel and Purchased Power Supply Services: All fuel for generating electric power and purchased power obtained by DEC or DEP from sources other than DEC or DEP for the purpose of providing Electric Services.

Fully Distributed Cost: All direct and indirect costs, including overheads and an appropriate cost of capital, incurred in providing goods or services to another business entity; provided, however, that (a) for each good or service supplied by DEC, DEP, or Piedmont, the return on common equity utilized in determining the appropriate cost of capital shall equal the return on common equity authorized by the Commission in the supplying utility's most recent general rate case proceeding; (b) for each good or service supplied to DEC, DEP, or Piedmont, the appropriate cost of capital shall not exceed the overall cost of capital authorized in the supplying utility's most recent general rate case proceeding; and (c) for each good or service supplied by DEC, DEP, or Piedmont to each other, the return on common equity utilized in determining the appropriate cost of capital shall not exceed the lower of the returns on common equity authorized by the Commission in DEC's, DEP's, or Piedmont's most recent general rate case proceeding, as applicable.

JDA: Joint Dispatch Agreement, which is the agreement as filed with the Commission in Docket Nos. E-7, Sub 986, and E-2, Sub 998, on June 22, 2011, and as amended and refiled on June 12, 2012.

Market Value: The price at which property, goods, or services would change hands in an arm's length transaction between a buyer and a seller without any compulsion to engage in a transaction, and both having reasonable knowledge of the relevant facts.

Merger: All transactions contemplated by the Agreement and Plan of Merger between Duke Energy and Piedmont.

Natural Gas Services: Commission-regulated natural gas sales and natural gas transportation, and other related services, including, but not limited to, administration of Customer accounts and rate schedules, metering and billing, and standby service.

Non-affiliated Gas Marketer: An entity, not affiliated with DEC, DEP, or Piedmont, engaged in the unregulated sale, arrangement, brokering or management of gas supply, pipeline capacity, or gas storage.

Nonpublic Utility Operations: All business operations engaged in by DEC, DEP, or Piedmont involving activities (including the sales of goods or services) that are not regulated by the Commission or otherwise subject to public utility regulation at the state or federal level.

Non-Utility Affiliate: Any Affiliate, including DEBS, other than a Utility Affiliate, DEC, DEP, or Piedmont.

Personnel: An employee or other representative of DEC, DEP, Piedmont, Duke Energy, another Affiliate, or a Nonpublic Utility Operation, who is involved in fulfilling the business purpose of that entity.

Piedmont: Piedmont Natural Gas Company, Inc., the business entity, wholly owned by Duke Energy, that holds the franchise granted by the Commission to provide Natural Gas Services within its North Carolina service territory and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

Progress Energy: Progress Energy, Inc., which is the former holding company parent of DEP and is a subsidiary of Duke Energy, and any successors.

Public Staff: The Public Staff of the North Carolina Utilities Commission.

Regulatory Conditions: The conditions imposed by the Commission in connection with or related to the Merger.

Shared Services: The services that meet the requirements of the Regulatory Conditions approved in Docket Nos. E-2, Sub 1095, E-7, Sub 1100, and G-9, Sub 682, or subsequent orders of the Commission and that the Commission has explicitly authorized DEC, DEP, and Piedmont to take from DEBS pursuant to a service agreement (a) filed with the Commission pursuant to G.S. 62-153(b), thus requiring acceptance and authorization by the Commission, and (b) subject to all other applicable provisions of North Carolina law, the rules and orders of the Commission, and the Regulatory Conditions.

Shipper: A Non-affiliated Gas Marketer, a municipal gas customer, or an end-user of gas.

Utility Affiliates: The regulated public utility operations of Duke Energy Indiana, LLC (Duke Indiana), Duke Energy Kentucky, Inc. (Duke Kentucky), Florida Power Corporation, d/b/a Progress Energy Florida, LLC (DEF), and Duke Energy Ohio, Inc. (Duke Ohio).

II. GENERAL

This Code of Conduct establishes the minimum guidelines and rules that apply to the relationships, transactions, and activities involving the public utility operations of DEC, DEP, Piedmont, Duke Energy, other Affiliates, or the Nonpublic Utility Operations of DEC, DEP, and Piedmont, to the extent such relationships, activities, and transactions affect the public utility operations of DEC, DEP, and Piedmont in their respective service areas. DEC, DEP, Piedmont, and the other Affiliates are bound by this Code of Conduct pursuant to Regulatory Condition 6.1 approved by the Commission in Docket Nos. E-2, Sub 1095, E-7, Sub 1100, and G-9, Sub 682. This Code of Conduct is subject to modification by the Commission as the public interest may require, including, but not limited to, addressing changes in the organizational structure of DEC, DEP, Piedmont, Duke Energy, other Affiliates, or the Nonpublic Utility Operations; changes in the structure of the electric industry or natural gas industry; or other changes that warrant modification of this Code.

DEC, DEP, or Piedmont may seek a waiver of any aspect of this Code of Conduct by filing a request with the Commission showing that circumstances in a particular case justify such a waiver.

III. STANDARDS OF CONDUCT

A. Independence and Information Sharing

1. Separation - DEC, DEP, Piedmont, Duke Energy, and the other Affiliates shall operate independently of each other and in physically separate locations to the maximum extent

practicable; however, to the extent that the Commission has approved or accepted a service company-to-utility or utility-to-utility service agreement or list, DEC, DEP, Piedmont, Duke Energy, and the other Affiliates may operate as described in the agreement or list on file at the Commission. DEC, DEP, Piedmont, Duke Energy, and each of the other Affiliates shall maintain separate books and records. Each of DEC's, DEP's, and Piedmont's Nonpublic Utility Operations shall maintain separate records from those of DEC's, DEP's, and Piedmont's public utility operations to ensure appropriate cost allocations and any arm's-length-transaction requirements.

2. Disclosure of Customer Information:

(a) Upon request, and subject to the restrictions and conditions contained herein, DEC, DEP, and Piedmont may provide Customer Information to Duke Energy or another Affiliate under the same terms and conditions that apply to the provision of such information to non-Affiliates. In addition, DEC and DEP may provide Customer Information to their respective Nonpublic Utility Operations under the same terms and conditions that apply to the provision of such information to non-Affiliates.

(b) Except as provided in Section III.A.2.(f), Customer Information shall not be disclosed to any Affiliate or non-affiliated third party without the Customer's consent, and then only to the extent specified by the Customer. Consent to disclosure of Customer Information to Affiliates of DEC, DEP, and Piedmont or to DEC's or DEP's Nonpublic Utility Operations may be obtained by means of written, electronic, or recorded verbal authorization upon providing the Customer with the information set forth in Attachment A; provided, however, that DEC, DEP, and Piedmont retain such authorization for verification purposes for as long as the authorization remains in effect. Written, electronic, or recorded verbal authorization or consent for the disclosure of Piedmont's Customer Information to Piedmont's Nonpublic Utility Operations is not required.

(c) If the Customer allows or directs DEC, DEP, or Piedmont to provide Customer Information to Duke Energy, another Affiliate, or to DEC's or DEP's Nonpublic Utility Operations, then DEC, DEP, or Piedmont shall ask if the Customer would like the Customer Information to be provided to one or more non-Affiliates. If the Customer directs DEC, DEP, or Piedmont to provide the Customer Information to one or more non-Affiliates, the Customer Information shall be disclosed to all entities designated by the Customer contemporaneously and in the same manner.

(d) Section III.A.2.shall be permanently posted on DEC's, DEP's and Piedmont's website(s).

(e) No DEC, DEP, or Piedmont employee who is transferred to Duke Energy or another Affiliate shall be permitted to copy or otherwise compile any Customer Information for use by such entity except as authorized by the Customer pursuant to a signed Data Disclosure Authorization. DEC, DEP, and Piedmont shall not transfer any employee to Duke Energy or another Affiliate for the purpose of disclosing or providing Customer Information to such entity.

(f) Notwithstanding the prohibitions in this Section III.A.2.:

(i) DEC, DEP, and Piedmont may disclose Customer Information to DEBS, any other Affiliate, or a non-affiliated third party without Customer consent to the extent necessary for the Affiliate or non-affiliated third party to provide goods or services to DEC, DEP, or Piedmont and upon the written agreement of the other Affiliate or non-affiliated third-party to protect the confidentiality of such Customer Information. To the extent the Commission approves a list of services to be provided and taken pursuant to one or more utility-to-utility service agreements, then Customer Information may be disclosed pursuant to the foregoing exception to the extent necessary for such services to be performed.

(ii) DEC and DEP may disclose Customer Information to their Nonpublic Utility Operations without Customer consent to the extent necessary for the Nonpublic Utility Operations to provide goods and services to DEC or DEP and upon the written agreement of the Nonpublic Utility Operations to protect the confidentiality of such Customer Information.

(iii) DEC, DEP, and Piedmont may disclose Customer Information to a state or federal regulatory agency or court of competent jurisdiction if required in writing to do so by the agency or court.

(g) DEC, DEP, and Piedmont shall take appropriate steps to store Customer Information in such a manner as to limit access to those persons permitted to receive it and shall require all persons with access to such information to protect its confidentiality.

(h) DEC, DEP, and Piedmont shall establish guidelines for its employees and representatives to follow with regard to complying with this Section III.A.2.

(i) No DEBS employee may use Customer Information to market or sell any product or service to DEC's, DEP's, or Piedmont's Customers, except in support of a Commission-approved rate schedule or program or a marketing effort managed and supervised directly by DEC, DEP, or Piedmont.

(j) DEBS employees with access to Customer Information must be prohibited from making any improper indirect use of the data, including directing or encouraging any actions based on the Customer Information by employees of DEBS that do not have access to such information, or by other employees of Duke Energy or other Affiliates or Nonpublic Utility Operations of DEC and DEP.

(k) Should any inappropriate disclosure of DEC, DEP, or Piedmont Customer Information occur at any time, DEC, DEP, or Piedmont shall promptly file a statement with the Commission describing the circumstances of the disclosure, the Customer information disclosed, the results of the disclosure, and the steps taken to mitigate the effects of the disclosure and prevent future occurrences.

3. The disclosure of Confidential Systems Operation Information of DEC, DEP, and Piedmont shall be governed as follows:

(a) Such CSOI shall not be disclosed by DEC, DEP, or Piedmont to an Affiliate or a Nonpublic Utility Operation unless it is disclosed to all competing non-Affiliates contemporaneously and in the same manner. Disclosure to non-Affiliates is not required under the following circumstances:

(i) The CSOI is provided to employees of DEC or DEP for the purpose of implementing, and operating pursuant to, the JDA in accordance with the Regulatory Conditions approved in Docket Nos. E-7, Sub 986, and E-2, Sub 998.

(ii) The CSOI is necessary for the performance of services approved to be performed pursuant to one or more Affiliate utility-to-utility service agreements.

(iii) A state or federal regulatory agency or court of competent jurisdiction over the disclosure of the CSOI requires the disclosure.

(iv) The CSOI is provided to employees of DEBS pursuant to a service agreement filed with the Commission pursuant to G.S. 62-153.

(v) The CSOI is provided to employees of DEC's, DEP's, or Piedmont's Utility Affiliates for the purpose of sharing best practices and otherwise improving the provision of regulated utility service.

(vi) The CSOI is provided to an Affiliate pursuant to an agreement filed with the Commission pursuant to G.S. 62-153, provided that the agreement specifically describes the types of CSOI to be disclosed.

(vii) Disclosure is otherwise essential to enable DEC or DEP to provide Electric Services to their Customers or for Piedmont to provide Natural Gas Services to its Customers.

(viii) Disclosure of the CSOI is necessary for compliance with the Sarbanes-Oxley Act of 2002.

(b) Any CSOI disclosed pursuant Section III.A.3.(a)(i)-(viii) shall be disclosed only to employees that need the CSOI for the purposes covered by those exceptions and in as limited a manner as possible. The employees receiving such CSOI must be prohibited from acting as conduits to pass the CSOI to any Affiliate(s) and must have explicitly agreed to protect the confidentiality of such CSOI.

(c) For disclosures pursuant to Section III.A.3.(a)(vii) and (viii), DEC, DEP, and Piedmont shall include in their annual affiliated transaction reports the following information:

(i) The types of CSOI disclosed and the name(s) of the Affiliate(s) to which it is being, or has been, disclosed;

(ii) The reasons for the disclosure; and

(iii) Whether the disclosure is intended to be a one-time occurrence or an ongoing process.

To the extent a disclosure subject to the reporting requirement is intended to be ongoing, only the initial disclosure and a description of any processes governing subsequent disclosures need to be reported.

(d) DEC, DEP, Piedmont, and DEBS employees with access to CSOI must be prohibited from making any improper indirect use of the data, including directing or encouraging any actions based on the CSOI by employees that do not have access to such information, or by other employees of Duke Energy or other Affiliates or Nonpublic Utility Operations of DEC, DEP, and Piedmont.

(e) Should the handling or disclosure of CSOI by DEBS, or another Affiliate or Nonpublic Utility Operation, or its respective employees, result in (i) a violation of DEC's or DEP's FERC Statement of Policy and Code of Conduct (FERC Code), 18 CFR 358 - Standards of Conduct for Transmission Providers (Transmission Standards), or any other relevant FERC standards or codes of conduct, (ii) the posting of such data on an Open Access Same-Time Information System (OASIS) or other Internet website, or (iii) other public disclosure of the data, DEC or DEP shall promptly file a statement with the Commission in Docket No. E-7, Sub 1100C, and E-2, Sub 1095C, respectively, describing the circumstances leading to such violation, posting, or other public disclosure describing the circumstances leading to such violation, posting, or other public disclosure, any data required to be posted or otherwise publicly disclosed, and the steps taken to mitigate the effects of the current and prevent any future potential violation, posting, or other public disclosure.

(f) Should any inappropriate disclosure of CSOI occur at any time, DEC, DEP, or Piedmont shall promptly file a statement with the Commission in Docket No. E-7, Sub 1100C, E-2, Sub 1095C, or G-9, Sub 682C, respectively, describing the circumstances of the disclosure, the CSOI disclosed, the results of the disclosure, and the steps taken to mitigate the effects of the disclosure and prevent future occurrences.

(g) Unless publicly noticed and generally available, should the FERC Code, the Transmission Standards, or any other relevant FERC standards or codes of conduct be eliminated, amended, superseded, or otherwise replaced, DEC and DEP shall file a letter with the Commission in Docket Nos. E-7, Sub 1100E, and E-2, Sub 1095E, describing such action within 60 days of the action, along with a copy of any amended or replacement document.

B. Nondiscrimination

1. DEC's, DEP's, and Piedmont's employees and representatives shall not unduly discriminate against non-Affiliated entities.

2. In responding to requests for Electric Services, Natural Gas Services, or both, DEC, DEP, and Piedmont shall not provide any preference to Duke Energy, another Affiliate, or a Nonpublic Utility Operation, or to any customers of such an entity, as compared to non-Affiliates or their customers. Moreover, neither DEC, DEP, Piedmont, Duke Energy, nor any other Affiliates shall represent to any person or entity that Duke Energy, another Affiliate, or a Nonpublic Utility Operation will receive any such preference.

3. DEC, DEP, and Piedmont shall apply the provisions of their respective tariffs equally to Duke Energy, the other Affiliates, the Nonpublic Utility Operations, and non-Affiliates.

4. DEC, DEP, and Piedmont shall process all similar requests for Electric Services, Natural Gas Services, or both, in the same timely manner, whether requested on behalf of Duke Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated entity.

5. No personnel or representatives of DEC, DEP, Piedmont, Duke Energy, or another Affiliate shall indicate, represent, or otherwise give the appearance to another party that Duke Energy or another Affiliate speaks on behalf of DEC, DEP, or Piedmont; provided however, that this prohibition shall not apply to employees of DEBS providing Shared Services or to employees of another Affiliate to the extent explicitly provided for in an affiliate agreement that has been accepted by the Commission. In addition, no personnel or representatives of a Nonpublic Utility Operation shall indicate, represent, or otherwise give the appearance to another party that they speak on behalf of DEC's or DEP's regulated public utility operations.

6. No personnel or representatives of DEC, DEP, Piedmont, Duke Energy, another Affiliate, or a Nonpublic Utility Operation shall indicate, represent, or otherwise give the appearance to another party that any advantage to that party with regard to Electric Services or Natural Gas Services exists as the result of that party dealing with Duke Energy, another Affiliate, or a Nonpublic Utility Operation, as compared with a non-Affiliate.

7. DEC, DEP, and Piedmont shall not condition or otherwise tie the provision or terms of any Electric Services or Natural Gas Services to the purchasing of any goods or services from, or the engagement in business of any kind with, Duke Energy, another Affiliate, or a Nonpublic Utility Operation.

8. When any employee or representative of DEC or DEP receives a request for information from or provides information to a Customer about goods or services available from Duke Energy, another Affiliate, or a Nonpublic Utility Operation, the employee or representative shall advise the Customer that such goods or services may also be available from non-Affiliated suppliers.

9. Disclosure of Customer Information to Duke Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated entity shall be governed by Section III.A.2. of this Code of Conduct.

10. Unless otherwise directed by order of the Commission, electric generation shall not receive a priority of use from Piedmont that would supersede or diminish Piedmont's provision of service to its human needs firm residential and commercial customers.

11. Piedmont shall file an annual report with the Commission summarizing all requests or inquiries for Natural Gas Services made by a non-utility generator, Piedmont's response to the request, and the status of the inquiry.

C. **Marketing**

1. The public utility operations of DEC, DEP, and Piedmont may engage in joint sales, joint sales calls, joint proposals, or joint advertising (a joint marketing arrangement) with their Affiliates and with their Nonpublic Utility Operations, subject to compliance with other provisions of this Code of Conduct and any conditions or restrictions that the Commission may hereafter establish. DEC, DEP, and Piedmont shall not otherwise engage in such joint activities without making such opportunities available to comparable third parties.

2. Neither Duke Energy nor any of the other Affiliates shall use the names or logos of DEC, DEP, or Piedmont in any communications without the following disclaimer:

(a) "[Duke Energy Corporation/Affiliate) is not the same company as [DEC/DEP/Piedmont], and [Duke Energy Corporation/Affiliate) has separate management and separate employees";
(b) "[Duke Energy Corporation/Affiliate] is not regulated by the North Carolina Utilities Commission or in any way sanctioned by the Commission";
(c) "Purchasers of products or services from [Duke Energy Corporation/Affiliate] will receive no preference or special treatment from [DEC/DEP/Piedmont]"; and
(d) "A customer does not have to buy products or services from [Duke Energy Corporation/Affiliate] in order to continue to receive the same safe and reliable electric service from [DEC/DEP] or natural gas service from Piedmont."

3. Nonpublic Utility Operations may not use the names or logos of DEC, DEP, or Piedmont in communications without the following disclaimer:

"[Name of product or service being offered by Nonpublic Utility Operation] is not part of the regulated services offered by [DEC/DEP/Piedmont] and is not in any way sanctioned by the North Carolina Utilities Commission."

4. In addition, DEC's and DEP's Nonpublic Utility Operations may not use the names or logos of DEC or DEP in any communications without the following disclaimers:

(a) "Purchasers of [name of product or service being offered by Nonpublic Utility Operation] from [Nonpublic Utility Operation] will receive no preference or special treatment from [DEC/DEP]"; and
(b) "A customer does not have to buy this product or service from [Nonpublic Utility Operation] in order to continue to receive the same safe and reliable electric service from [DEC/DEP]."

The required disclaimers in this Section III.C.4. must be sized and displayed in a way that is commensurate with the name and logo so that the disclaimer is at least the larger of one-half the size of the type that first displays the name and logo or the predominant type used in the communication.

D. Transfers of Goods and Services, Transfer Pricing, and Cost Allocation

1. Cross-subsidies involving DEC, DEP, or Piedmont and Duke Energy, other Affiliates, or the Nonpublic Utility Operations are prohibited.

2. All costs incurred by personnel or representatives of DEC, DEP, or Piedmont for or on behalf of Duke Energy, other Affiliates, or the Nonpublic Utility Operations shall be charged to the entity responsible for the costs.

3. The following conditions shall apply as a general guideline to the transfer prices charged for goods and services, including the use or transfer of personnel, exchanged between and among DEC, DEP, or Piedmont, and Duke Energy, the other Non-Utility Affiliates, and the Nonpublic Utility Operations, to the extent such prices affect DEC's, DEP's, or Piedmont's operations or costs of utility service:

(a) Except as otherwise provided for in this Section III.D., for untariffed goods and services provided by DEC, DEP, or Piedmont to Duke Energy, a Non-Utility Affiliate, or a Nonpublic Utility Operation, the transfer price paid to DEC, DEP, or Piedmont shall be set at the higher of Market Value or DEC's, DEP's, or Piedmont's Fully Distributed Cost.

(b) Except as otherwise provided for in this Section III.D., for goods and services provided, directly or indirectly, by Duke Energy, a Non-Utility Affiliate other than DEBS, or a Nonpublic Utility Operation to DEC, DEP, or Piedmont, the transfer price(s) charged by Duke Energy, the Non-Utility Affiliate, and the Nonpublic Utility Operation to DEC, DEP, or Piedmont shall be set at the lower of Market Value or Duke Energy's, the Non-Utility Affiliate's, or the Nonpublic Utility Operation's Fully Distributed Cost(s). If DEC, DEP, or Piedmont do not engage in competitive solicitation and instead obtain the goods or services from Duke Energy, a Non-Utility Affiliate, or a Nonpublic Utility Operation, DEC, DEP, and Piedmont shall implement adequate processes to comply with this Code provision and related Regulatory Conditions and ensure that in each case DEC's, DEP's, and Piedmont's Customers receive service at the lowest reasonable cost, unless otherwise directed by order of the Commission. For goods and services provided by DEBS to DEC, DEP, Piedmont, and Utility Affiliates, the transfer price charged shall be set at DEBS' Fully Distributed Cost.

(c) Tariffed goods and services provided by DEC, DEP, and Piedmont to Duke Energy, other Affiliates, or a Nonpublic Utility Operation shall be provided at the same prices and terms that are made available to Customers having similar characteristics with regard to Electric Services or Natural Gas Services under the applicable tariff.

(d) With the exception of gas supply transactions, transportation transactions, or both, between DEC and Piedmont or DEP and Piedmont, untariffed non-power, non-generation, or non-fuel goods and services provided by DEC, DEP, or Piedmont to DEC, DEP, Piedmont, or the Utility Affiliates or by the Utility Affiliates to DEC, DEP, or Piedmont, shall be transferred at the supplier's Fully Distributed Cost, unless otherwise directed by order of the Commission.

(e) All Piedmont deliveries to DEC and DEP pursuant to intrastate negotiated sales or transportation arrangements and combinations of sales and transportation transactions shall be at the same price and terms that are made available to other Shippers having comparable characteristics, such as nature of service (firm or interruptible, sales or transportation), pressure requirements, nature of load (process/heating/electric generation), size of load, profile of load (daily, monthly, seasonal, annual), location on Piedmont's system, and costs to serve and rates. Piedmont shall maintain records in sufficient detail to demonstrate compliance with this requirement.

(f) All gas supply transactions, interstate transportation and storage transactions, and combinations of these transactions, between DEC or DEP and Piedmont shall be at the fair market value for similar transactions between non-affiliated third parties. DEC, DEP, and Piedmont shall maintain records, such as published market price indices, in sufficient detail to demonstrate compliance with this requirement.

(g) All of the margins, also referred to as net compensation, received by Piedmont on secondary market sales to DEC and DEP shall be recorded in Piedmont's Deferred Gas Cost Accounts and shall flow through those accounts for the benefit of ratepayers. None of the margins on secondary market sales by Piedmont to DEC and DEP shall be included in the secondary market transactions subject to the sharing mechanism on secondary market transactions approved by the Commission in its Order Approving Stipulation, dated December 22, 1995, in Docket No. G-100, Sub 67. The sharing percentage on secondary market sales shall not be considered in determining the prudence of such transactions.

4. To the extent that DEC, DEP, Piedmont, Duke Energy, other Affiliates, or the Nonpublic Utility Operations receive Shared Services from DEBS (or its successor), these Shared Services may be jointly provided to DEC, DEP, Piedmont, Duke Energy, other Affiliates, or the Nonpublic Utility Operations on a fully distributed cost basis, provided that the taking of such Shared Services by DEC, DEP, and Piedmont is cost beneficial on a service-by-service (e.g., accounting management, human resources management, legal services, tax administration, public affairs) basis to DEC, DEP, and Piedmont. Charges for such Shared Services shall be allocated in accordance with the cost allocation manual filed with the Commission pursuant to Regulatory Condition 5.5, subject to any revisions or other adjustments that may be found appropriate by the Commission on an ongoing basis.

5. DEC, DEP, Piedmont, and their Utility Affiliates may capture economies-of-scale in joint purchases of goods and services (excluding the purchase of electricity or ancillary services

intended for resale unless such purchase is made pursuant to a Commission-approved contract or service agreement), if such joint purchases result in cost savings to DEC's, DEP's, and Piedmont's Customers. DEC, DEP, Piedmont, and their Utility Affiliates may capture economies-of-scale in joint purchases of coal and natural gas, if such joint purchases result in cost savings to DEC's, DEP's, and Piedmont's Customers. All joint purchases entered into pursuant to this section shall be priced in a manner that permits clear identification of each participant's portion of the purchases and shall be reported in DEC's, DEP's, and Piedmont's affiliated transaction reports filed with the Commission.

6. All permitted transactions between DEC, DEP, Piedmont, Duke Energy, other Affiliates, and the Nonpublic Utility Operations shall be recorded and accounted for in accordance with the cost allocation manual required to be filed with the Commission pursuant to Regulatory Condition 5.5 and with Affiliate agreements accepted by the Commission or otherwise processed in accordance with North Carolina law, the rules and orders of the Commission, and the Regulatory Conditions.

7. Costs that DEC, DEP, and Piedmont incur in assembling, compiling, preparing, or furnishing requested Customer Information or CSOI for or to Duke Energy, other Affiliates, Nonpublic Utility Operations, or non-Affiliates (other than the Customer or the Customer's designated representative or agent) shall be recovered from the requesting party pursuant to Section III.D.3. of this Code of Conduct.

8. Any technology or trade secrets developed, obtained, or held by DEC, DEP, or Piedmont in the conduct of regulated operations shall not be transferred to Duke Energy, another Affiliate, or a Nonpublic Utility Operation without just compensation and the filing of 60-days prior notification to the Commission. DEC, DEP, and Piedmont are not required to provide advance notice for such transfers to each other and may request a waiver of this requirement from the Commission with respect to such transfers to Duke Energy, a Utility Affiliate, a Non-Utility Affiliate, or a Nonpublic Utility Operation. In no case, however, shall the notice period requested be less than 20 business days.

9. DEC, DEP, and Piedmont shall receive compensation from Duke Energy, other Affiliates, and the Nonpublic Utility Operations for intangible benefits, if appropriate.

E. Regulatory Oversight

1. The requirements regarding affiliate transactions set forth in G.S. 62-153 shall continue to apply to all transactions between DEC, DEP, Piedmont, Duke Energy, and the other Affiliates.

2. The books and records of DEC, DEP, Piedmont, Duke Energy, other Affiliates, and the Nonpublic Utility Operations shall be open for examination by the Commission, its staff, and the Public Staff as provided in G.S. 62-34, 62-37, and 62-51.

3. If Piedmont supplies any Natural Gas Services, with the exception of Natural Gas Services provided pursuant to Commission-approved contracts or service agreements, used by either DEC or DEP to generate electricity, DEC or DEP, as applicable, shall file a report with the

Commission in its annual fuel and fuel-related cost recovery case demonstrating that the purchase was prudent and the price was reasonable.

4. To the extent North Carolina law, the orders and rules of the Commission, and the Regulatory Conditions permit Duke Energy, an Affiliate, or a Nonpublic Utility Operation to supply DEC, DEP, or Piedmont with Natural Gas Services or other Fuel and Purchased Power Supply Services used by DEC or DEP to provide Electric Services to Customers, and to the extent such Natural Gas Services or other Fuel and Purchased Power Supply Services are supplied, DEC or DEP, as applicable, shall demonstrate in its annual fuel adjustment clause proceeding that each such acquisition was prudent and the price was reasonable.

F. Utility Billing Format

To the extent any bill issued by DEC, DEP, Piedmont, Duke Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated third party includes charges to Customers for Electric Services or Natural Gas Services and non-Electric Services, non-Natural Gas Services, or any combination of such services, from Duke Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated third party, the charges for Electric Services and Natural Gas Services shall be separated from the charges for any other services included on the bill. Each such bill shall contain language stating that the Customer's Electric Services and Natural Gas Services will not be terminated for failure to pay for any other services billed.

G. Complaint Procedure

1. DEC, DEP, and Piedmont shall establish procedures to resolve potential complaints that arise due to the relationship of DEC, DEP, and Piedmont with Duke Energy, the other Affiliates, and the Nonpublic Utility Operations. The complaint procedures shall provide for the following:

(a) Verbal and written complaints shall be referred to a designated representative of DEC, DEP, or Piedmont.
(b) The designated representative shall provide written notification to the complainant within 15 days that the complaint has been received.
(c) DEC, DEP, or Piedmont shall investigate the complaint and communicate the results or status of the investigation to the complainant within 60 days of receiving the complaint.
(d) DEC, DEP, and Piedmont shall each maintain a log of complaints and related records and permit inspection of documents (other than those protected by the attorney/client privilege) by the Commission, its staff, or the Public Staff.

2. Notwithstanding the provisions of Section III.G.1., any complaints received through Duke Energy's EthicsLine (or successor), which is a confidential mechanism available to the employees of the Duke Energy holding company system, shall be handled in accordance with procedures established for the EthicsLine.

3. These complaint procedures do not affect a complainant's right to file a formal complaint with the Commission or otherwise communicate with the Commission or the Public Staff regarding a complaint.

H. Natural Gas/Electricity Competition

DEC, DEP and Piedmont shall continue to compete against all energy providers, including each other, to serve those retail customer energy needs that can be legally and profitably served by both electricity and natural gas. The competition between DEC or DEP and Piedmont shall be at a level that is no less than that which existed prior to the Merger. Without limitation as to the full range of potential competitive activity, DEC, DEP and Piedmont shall maintain the following minimum standards:

1. Piedmont will make all reasonable efforts to extend the availability of natural gas to as many new customers as possible.

2. In determining where and when to extend the availability of natural gas, Piedmont will at a minimum apply the same standards and criteria that it applied prior to the Merger.

3. In determining where and when to extend the availability of natural gas, Piedmont will make decisions in accordance with the best interests of Piedmont, rather than the best interest of DEC or DEP.

4. To the extent that either the natural gas industry or the electricity industry is further restructured, DEC, DEP, and Piedmont will undertake to maintain the full level of competition intended by this Code of Conduct subject to the right of DEC, DEP, Piedmont or the Public Staff to seek relief from or modifications to this requirement by the Commission.

CODE OF CONDUCT
ATTACHMENT A

DEC/DEP/PIEDMONT CUSTOMER INFORMATION DISCLOSURE AUTHORIZATION

For Disclosure to Affiliates:

DEC's/DEP's/Piedmont's Affiliates offer products and services that are separate from the regulated services provided by DEC/DEP/Piedmont. These services are not regulated by the North Carolina Utilities Commission. These products and services may be available from other competitive sources.

The Customer authorizes DEC/DEP/Piedmont to provide any data associated with the Customer account(s) residing in any DEC/DEP/Piedmont files, systems or databases **[or specify specific types of data]** to the following Affiliate(s) ________________. DEC/DEP/Piedmont will provide this data on a non-discriminatory basis to any other person or entity upon the Customer's authorization.

For Disclosure to Nonpublic Utility Operations:

DEC/DEP offers optional, market-based products and services that are separate from the regulated services provided by DEC/DEP. These services are not regulated by the North Carolina Utilities Commission. These products and services may be available from other competitive sources.

The Customer authorizes DEC/DEP to use any data associated with the Customer account(s) residing in any DEC/DEP files, systems or databases **[or specify types of data]** for the purpose of offering and providing energy-related products or services to the Customer. DEC/DEP will provide this data on a non-discriminatory basis to any other person or entity upon the Customer's authorization.

APPENDIX B

DOCKET NO. E-2, SUB 1095
DOCKET NO. E-7, SUB 1100
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REGULATORY CONDITIONS AND CODE OF CONDUCT

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REGULATORY CONDITIONS

These Regulatory Conditions set forth commitments made by Duke Energy Corporation (Duke Energy) and its public utility subsidiaries, Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP), and Piedmont Natural Gas Company, Inc. (Piedmont), as a precondition of approval of the application by Duke Energy and Piedmont pursuant to G.S. 62-111(a) for authority to engage in their proposed business combination transaction. These Regulatory Conditions, which become effective only upon closing of the Merger, shall apply jointly and severally to Duke Energy, DEC, DEP, and Piedmont, and shall be interpreted in the manner that most effectively fulfills the Commission's purposes as set forth in the preamble to Section II of these Regulatory Conditions.

SECTION I
DEFINITIONS

For the purposes of these Regulatory Conditions, capitalized terms shall have the meanings set forth below. If a capitalized term is not defined below, it shall have the meaning provided elsewhere in this document or as commonly used in the electric or natural gas utility industry.

Affiliate: Duke Energy and any business entity of which ten percent (10%) or more is owned or controlled, directly or indirectly, by Duke Energy. For purposes of these Regulatory Conditions, Duke Energy and each business entity so controlled by it are considered to be Affiliates of DEC, DEP, and Piedmont, and DEC, DEP, and Piedmont are considered to be Affiliates of each other.

Affiliate Contract: (a) Any contract or agreement between or among DEC, DEP, and Piedmont or between or among DEC, DEP, or Piedmont and any other Affiliate or proposed Affiliate, and (b) any contract or agreement between such other Affiliate or proposed Affiliate and another Affiliate that is related to the same subject matter and is reasonably likely to have an Effect on DEC's, DEP's, or Piedmont's Rates or Service. Such contracts and agreements include, but are not limited to, service, operating, interchange, pooling, wholesale power sales agreements and agreements involving financings and asset transfers and sales, and the Joint Dispatch Agreement.

Catawba Joint Owners: The North Carolina Electric Membership Corporation, North Carolina Municipal Power Agency No. 1, and Piedmont Municipal Power Agency. For purposes of these Regulatory Conditions, DEC is not included in the definition of Catawba Joint Owners.

Code of Conduct: The minimum guidelines and rules approved by the Commission that govern the relationships, activities, and transactions between and among the public utility operations of DEC, DEP, and Piedmont, Duke Energy, the other Affiliates of DEC, DEP, and Piedmont, and the Nonpublic Utility Operations of DEC, DEP, and Piedmont, as those guidelines and rules may be amended by the Commission from time to time.

ELECTRIC – MISCELLANEOUS

Commission: The North Carolina Utilities Commission.

Customer: Any retail electric customer of DEC or DEP in North Carolina and any Commission-regulated natural gas sales or natural gas transportation customer of Piedmont located in North Carolina.

DEBS: Duke Energy Business Services, LLC, and its successors, which is a service company Affiliate that provides Shared Services to DEC, DEP, Piedmont, Duke Energy, other Affiliates, or the Nonpublic Utility Operations of DEC, DEP or Piedmont, singly or in any combination.

DEC: Duke Energy Carolinas, LLC, the business entity, wholly owned by Duke Energy, that holds the franchise granted by the Commission to provide Electric Services within DEC's North Carolina service territory and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

DEP: Duke Energy Progress. LLC, the business entity, wholly owned by Duke Energy, that holds the franchises granted by the Commission to provide Electric Services within the DEP's North Carolina service territory and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

Duke Energy: Duke Energy Corporation, which is the current holding company parent of DEC, DEP, and Piedmont, and any successor company.

Effect on DEC's, DEP's, or Piedmont's Rates or Service: When used with reference to the consequences to DEC, DEP, or Piedmont of actions or transactions involving an Affiliate or Nonpublic Utility Operation, this phrase has the same meaning that it has when the Commission interprets G.S. 62-3(23)(c) with respect to the affiliation covered therein.

Electric Services: Commission-regulated electric power generation, transmission, distribution, delivery, and sales, and other related services, including, but not limited to, administration of Customer accounts and rate schedules, metering, billing, standby service, backups, and changeovers of service to other suppliers.

Federal Law: Any federal statute or legislation, or any regulation, order, decision, rule or requirement promulgated or issued by an agency or department of the federal government.

FERC: The Federal Energy Regulatory Commission.

Fully Distributed Cost: All direct and indirect costs, including overheads and an appropriate cost of capital, incurred in providing goods or services to another business entity; provided, however, that (a) for each good or service supplied by or from DEC, DEP, or Piedmont, the return on common equity utilized in determining the appropriate cost of capital shall equal the return on common equity authorized by the Commission in the supplying utility's most recent general rate case proceeding, (b) for each good or service supplied to DEC, DEP, or Piedmont, the appropriate cost of capital shall not exceed the overall cost of capital authorized in the supplying utility's most recent general rate case proceeding; and (c) for each good or service supplied by or from DEC, DEP, or Piedmont to each other, the return on common equity utilized in determining the appropriate cost of capital shall not exceed the lower of the returns on common equity authorized by the Commission in DEC's, DEP's, or Piedmont's most recent general rate case proceeding, as applicable.

JDA: Joint Dispatch Agreement, which is the agreement as filed with the Commission in Docket Nos. E-7, Sub 986, and E-2, Sub 998, on June 22, 2011, and as amended and refiled on June 12, 2012.

Market Value: The price at which property, goods, or services would change hands in an arm's length transaction between a buyer and a seller without any compulsion to engage in a transaction, and both having reasonable knowledge of the relevant facts.

Merger: All transactions contemplated by the Agreement and Plan of Merger between Duke Energy and Piedmont.

Native Load Priority: Power supply service being provided or electricity otherwise being sold with a priority of service equivalent to that planned for and provided by DEC or DEP to their respective Retail Native Load Customers.

Natural Gas Services: Commission-regulated natural gas sales and natural gas transportation, and other related services, including, but not limited to, administration of Customer accounts and rate schedules, metering and billing, and standby service.

Non-Native Load Sales: DEC's or DEP's sales of energy at wholesale, not including transactions between DEC and DEP pursuant to the JDA and not including service to customers served at Native Load Priority.

Nonpublic Utility Operations: All business operations engaged in by DEC, DEP, or Piedmont involving activities (including the sales of goods or services) that are not regulated by the Commission or otherwise subject to public utility regulation at the state or federal level.

Non-Utility Affiliate: Any Affiliate, including DEBS, other than a Utility Affiliate, DEC, DEP, or Piedmont.

Piedmont: Piedmont Natural Gas Company, Inc., the business entity, wholly owned by Duke Energy, that holds the franchise granted by the Commission to provide Natural Gas Services within its North Carolina service territory and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

Progress Energy: Progress Energy, Inc., which is the former holding company parent of DEP and is a subsidiary of Duke Energy, and any successors:

Public Staff: The Public Staff of the North Carolina Utilities Commission.

PUHCA 2005: The Public Utility Holding Company Act of 2005.

Purchased Power Resources: Purchases of energy by DEC or DEP at wholesale from sellers other than each other, the contract terms for which are one year or longer.

Retail Native Load Customers: The captive retail Customers of DEC and DEP in North Carolina for which DEC and DEP have the obligation under North Carolina law to engage in long-term planning and to supply all Electric Services, including installing or contracting for capacity, if needed, to reliably meet their electricity needs.

Retained Earnings: The retained earnings currently required to be listed on page 112, line 11, of the pre-Merger DEC FERC Form 1, the pre-Merger DEP FERC Form 1, and page 112, line 11 of the pre-Merger Piedmont FERC Form 2.

Shared Services: The services that meet the requirements of these Regulatory Conditions and that the Commission has explicitly authorized DEC, DEP, and Piedmont to take from DEBS pursuant to a service agreement (a) filed with the Commission pursuant to G.S. 62-153(b), thus requiring acceptance and authorization by the Commission, and (b) subject to all other applicable provisions of North Carolina law, the rules and orders of the Commission, and these Regulatory Conditions.

Utility Affiliates: The regulated public utility operations of Duke Energy Indiana, LLC (Duke Indiana), Duke Energy Kentucky, Inc. (Duke Kentucky), Florida Power Corporation, d/b/a Duke Energy Florida, LLC (DEF), and Duke Energy Ohio, Inc. (Duke Ohio).

SECTION II
AUTHORITY, SCOPE, AND EFFECT

These Regulatory Conditions are based on the general power and authority granted to the Commission in Chapter 62 of the North Carolina General Statutes to control and supervise the public utilities of the State. The Regulatory Conditions address specific exercises of the Commission's authority and provide mechanisms that enable the Commission to determine the extent of its authority and jurisdiction over proposed activities of, and transactions involving, DEC, DEP, Piedmont, Duke Energy, other Affiliates or Nonpublic Utility Operations. The purpose of these Regulatory Conditions is to ensure that DEC's and DEP's Retail Native Load Customers and Piedmont's Customers (a) are protected from any known adverse effects from the Merger, (b) are protected as much as possible from potential costs and risks resulting from the Merger, and (c) receive sufficient known and expected benefits to offset any potential costs and risks resulting from the Merger. These Regulatory Conditions are not intended to impose legal obligations on entities in which Duke Energy does not directly or indirectly have a controlling voting interest, or to affect any rights of any party to participate in subsequent proceedings.

2.1 Commission Authority Over Certain Transactions. DEC, DEP, Piedmont, Duke Energy, and other Affiliates acknowledge that the Commission has authority over intra-company transactions as provided for in Chapter 62.

2.2 Limited Right to Challenge Commission Orders. Other than as provided for, or explicitly prohibited, in these conditions, Duke Energy, DEC, DEP, Piedmont, and other Affiliates retain the right to challenge the lawfulness of any Commission order issued pursuant to or relating to these Regulatory Conditions on the basis that such order exceeds the Commission's statutory authority under North Carolina or Federal law or the other grounds listed in G.S. 62-94(b).

2.3 Waiver Request. DEC, DEP, Piedmont, Duke Energy, and other Affiliates may seek a waiver of any aspect of these Regulatory Conditions in a particular case or circumstance for good cause shown by filing a such request with the Commission.

SECTION III
PROTECTION OF RIGHTS

The following Regulatory Conditions are intended to protect the jurisdiction of the Commission as a result of the Merger, including risks related to agreements and transactions between and among DEC, DEP, Piedmont, and any of their Affiliates; financing transactions involving Duke Energy, DEC, DEP, or Piedmont, and any other Affiliate; and the ownership, use, and disposition of assets by DEC, DEP, or Piedmont.

3.1 Transactions between DEC, DEP, Piedmont, and Other Affiliates; Notice of Affiliate Contracts to be Filed with the FERC.

(a) DEC, DEP, and Piedmont shall not engage in any transactions with Affiliates or proposed Affiliates without first filing the proposed contracts or agreements memorializing such transactions pursuant to G.S. 62-153 and taking such actions and obtaining from the Commission such determinations and authorizations as may be required under North Carolina law. DEC, DEP, or Piedmont, as applicable, shall submit each proposed Affiliate Contract or substantive amendment to an existing Affiliate Contract to the Public Staff for informal review at least 15 days before filing it with the Commission. If DEC, DEP, or Piedmont and the Public Staff agree within the 15-day period that the proposed Affiliate Contract or substantive amendment to an existing Affiliate Contract does not require any action by the Commission, DEC, DEP, or Piedmont may proceed to execute the agreement subject to later disapproval and voidance by the Commission pursuant to G.S. 62-153(a). Otherwise, the proposed Affiliate Contract or substantive amendment to an existing Affiliate Contract shall not be executed until the agreement has been filed and payment of compensation has been approved by the Commission pursuant to G.S. 62-153(b).

(b) In addition to the requirements of Regulatory Condition 3.1(a), for any contract requiring filing with FERC, DEC, DEP, or Piedmont shall file, for informational purposes, a copy of a proposed Affiliate Contract, a contract with a proposed Affiliate, or an amendment to an existing Affiliate Contract with the Commission at least 15 days prior to filing with FERC.

3.2 Financing Transactions Involving DEC, DEP, Piedmont, Duke Energy, or Other Affiliates.

(a) With respect to any financing transaction between or among DEC, DEP, or Piedmont and Duke Energy or any one or more other Affiliates, any contract memorializing such transaction shall expressly provide that DEC, DEP, or Piedmont shall not enter into any such financing transaction except in accordance with North Carolina law and the rules, regulations and orders of the Commission promulgated thereunder; and

(b) With respect to any financing transaction (i) between or among any of the Affiliates if such contracts are reasonably likely to have an Effect on DEC's, DEP's, or Piedmont's Rates or Service, or (ii) between or among DEC, DEP, and Piedmont or between DEC, DEP, or Piedmont and any other Affiliate, any contract memorializing such transaction shall expressly provide that DEC, DEP, or Piedmont shall not include the effects of any capital structure or debt or equity costs associated with such financing transaction in its North Carolina retail cost of service or rates except as allowed by the Commission.

3.3 Ownership and Control of Assets Used by DEC, DEP, and Piedmont to Supply Electric Power or Natural Gas Services to North Carolina Customers; Transfer of Ownership or Control.

(a) DEC, DEP, and Piedmont shall own and control all assets or portions of assets used for the generation, transmission, and distribution of electric power or the transmission, storage, or distribution of natural gas to their respective Customers (with the exception of assets solely used to provide power purchased by DEC or DEP at wholesale).

(b) With respect to the transfer by DEC, DEP, or Piedmont to any entity, affiliated or not, of the control of, operational responsibility for, or ownership of generation, transmission, or distribution assets with a gross book value in excess of ten million dollars ($10 million), DEC, DEP, or Piedmont shall provide written notice to the Commission at least 30 days in advance of the proposed transfer. The provisions of Regulatory Condition 13.2 shall apply to an advance notice filed pursuant to this Regulatory Condition.

(c) Any contract memorializing such a transfer shall include the following language:

(i) DEC, DEP, or Piedmont may not commit to or carry out the transfer except in accordance with applicable law, and the rules, regulations and orders of the Commission promulgated thereunder; and

(ii) DEC, DEP, or Piedmont may not include in its North Carolina cost of service or rates the value of the transfer, except as allowed by the Commission in accordance with North Carolina law.

3.4 Purchases and Sales of Electricity and Natural Gas between DEC, DEP, Piedmont, and Duke Energy, Other Affiliates, or Nonpublic Utility Operations. Subject to additional restrictions set forth in the Code of Conduct, neither DEC, DEP, nor Piedmont shall purchase electricity (or related ancillary services) or natural gas from Duke Energy, another

Affiliate, or a Nonpublic Utility Operation under circumstances where the total all-in costs, including generation, transmission, ancillary costs, distribution, taxes and fees, and delivery point costs, incurred (whether directly or through allocation), based on information known, anticipated, or reasonably available at the time of purchase, exceed fair Market Value for comparable service, nor shall DEC, DEP, or Piedmont sell electricity (or related ancillary services) or natural gas to Duke Energy, another Affiliate, or a Nonpublic Utility Operation for less than fair Market Value; provided, however, that such restrictions shall not apply to emergency transactions. This condition shall not apply to transactions between DEC and DEP that are governed by the JDA.

3.5 Least Cost Integrated Resource Planning and Resource Adequacy. This Regulatory Condition does not apply to Piedmont. DEC and DEP shall retain the obligation to pursue least cost integrated resource planning for their respective Retail Native Load Customers and remain responsible for their own resource adequacy subject to Commission oversight in accordance with North Carolina law. DEC and DEP shall determine the appropriate self-built or purchased power resources to be used to provide future generating capacity and energy to their respective Retail Native Load Customers, including the siting considered appropriate for such resources, on the basis of the benefits and costs of such siting and resources to those Retail Native Load Customers.

3.6 Priority of Service.

(a) This Regulatory Condition does not apply to Piedmont.
(b) The planning and joint dispatch of DEC's system generation and Purchased Power Resources shall ensure that DEC's Retail Native Load Customers receive the benefits of that generation and those resources, including priority of service, to meet their electricity needs consistent with the JDA. DEC shall continue to serve its Retail Native Load Customers with the lowest-cost power it can reasonably generate or obtain as Purchase Power Resources before making power available for sales to customers that are not entitled to the same level of priority as Retail Native Load Customers.
(c) The planning and joint dispatch of DEP's system generation and Purchase Power Resources shall ensure that DEP's Retail Native Load Customers receive the benefits of that generation and those resources, including priority of service, to meet their electricity needs consistent with the JDA. DEP shall continue to serve its Retail Native Load Customers with the lowest-cost power it can reasonably generate or obtain as Purchase Power Resources before making power available for sales to customers that are not entitled to the same level of priority as Retail Native Load Customers.

3.7 Wholesale Power Contracts Granting Native Load Priority.

(a) This Regulatory Condition does not apply to Piedmont.
(b) DEC is not required to notify the Commission when it enters into wholesale power contracts that grant Native Load Priority to the following historically served customers: the City of Concord, North Carolina; the City of Kings Mountain, North Carolina; the Town of Dallas, North Carolina; the Town of Forest City, North

Carolina; Lockhart Power Company; the Public Works Commission of the Town of Due West, South Carolina; the Town of Prosperity, South Carolina; the City of Greenwood, South Carolina; the Town of Highlands; North Carolina; Western Carolina University (WCU); the electric membership cooperatives (EMCs) within DEC's control area; North Carolina Municipal Power Agency No. 1; Piedmont Municipal Power Agency; New River Light & Power Company; and the South Carolina distribution cooperatives historically served by Saluda River Electric Cooperative, Inc., and currently served by Central Electric Power Cooperative, Inc. (which are Blue Ridge Electric Cooperative, Inc., Broad River Electric Cooperative Inc., Laurens Electric Cooperative, Inc., Little River Electric Cooperative, Inc., and York Electric Cooperative, Inc.). Subject to the conditions set out in Regulatory Condition 3.8, the retail native loads of these historically served wholesale customers shall be considered DEC's Retail Native Load Customers for purposes of Regulatory Conditions 3.5, 3.6, and 4.5; provided, however, that this subsection applies only to the same types of supplemental load and backstand requirements services that were historically provided to the Catawba Joint Owners under the Catawba Interconnection Agreements between DEC and the Catawba Joint Owners prior to 2001, which, for the North Carolina Electric Membership Corporation, only includes the EMCs within DEC's control area.

(c) DEP is not required to notify the Commission when it enters into wholesale power contracts that grant Native Load Priority to the Public Works Commission of the City of Fayetteville, North Carolina; the Town of Waynesville, North Carolina; the City of Camden, South Carolina; the French Broad Electric Membership Corporation; the North Carolina Eastern Municipal Power Agency; the electric membership cooperatives (EMCs) within DEP's control area, whether served through the North Carolina Electric Membership Corporation (NCEMC) or individually; the Town of Black Creek, North Carolina; the Town of Lucama, North Carolina; the Town of Stantonsburg, North Carolina; the Town of Sharpsburg, North Carolina; and the Town of Winterville, North Carolina. Subject to the conditions set out in Regulatory Condition 3.8, the retail native loads of these historically served wholesale customers shall be considered DEP's Retail Native Load Customers for purposes of Regulatory Conditions 3.5, 3.6, and 4.5.

(d) Before either DEC or DEP executes any contract that grants Native Load Priority to a wholesale customer (other than as set forth in subdivisions (a) and (b) above) or to one or more retail customers of another entity, it shall, for informational purposes, provide the Public Staff with at least 15 days' written advance notice of its intent to grant Native Load Priority and to treat the retail native load of a proposed wholesale customer as if it were DEC's or DEP's retail native load pursuant to Regulatory Conditions 3.5, 3.6, and 4.5.

3.8 Additional Provisions Regarding Wholesale Contracts Entered into by DEC or DEP as Sellers.

(a) This Regulatory Condition does not apply to Piedmont.

(b) The Commission retains the right to assign, allocate, impute, and make pro-forma adjustments with respect to the revenues and costs for retail ratemaking and regulatory accounting and reporting purposes.

(c) DEC and DEP acknowledge that when either DEC or DEP enters into wholesale contracts that grant Native Load Priority or otherwise obligate DEC or DEP to construct generating facilities or make commitments to purchase capacity and energy to meet those contractual commitments such action constitutes acceptance by DEC, DEP, Duke Energy, and other Affiliates or Nonpublic Utility Operations thereof of the risks that investments in generating facilities or commitments to purchase capacity and energy to meet such contractual commitments and maintain an adequate reserve margin throughout the term of such contracts may become uneconomic sunk costs that may not be recoverable from DEC's or DEP's respective Retail Native Load Customers. In a future Commission retail proceeding in which cost recovery is at issue, neither DEC nor DEP shall claim that it does not bear this risk, and both DEC and DEP shall acknowledge that the Commission retains full authority under Chapter 62 to ascertain whether such costs are used and useful. For purposes of this condition, capacity will be considered used and useful and not excess capacity to the extent the Commission determines such capacity is needed by DEC or DEP to meet the expected peak loads of DEC's or DEP's respective Retail Native Load Customers in the near term future plus a reserve margin comparable to that currently being used or otherwise considered appropriate by the Commission.

(d) Except as provided in the foregoing conditions, DEC and DEP retain the right to challenge the lawfulness of any order issued by the Commission in connection with the assignment, allocation, imputation, pro-forma adjustments to, or disallowances of the revenues and costs associated with DEC's or DEP's wholesale contracts for retail ratemaking and regulatory accounting and reporting purposes on any other grounds, including but not limited to the right outlined in G.S. 62-94(b).

3.9 Other Protections.

(a) DEC, DEP, Piedmont, Duke Energy, another Affiliate, and a Nonpublic Utility Operation shall not assert in any forum – whether judicial, administrative, federal, state, local or otherwise – that the Commission's authority to determine the reasonableness or prudence of DEC's, DEP's, or Piedmont's decisions with respect to supply-side resources, demand-side management, or any other aspect of resource adequacy is limited.

(b) No agreement shall be entered into by or on behalf of DEC or DEP, that (i) commits DEC or DEP to, or involves either of them in, joint planning, coordination, dispatch or operation of generation, transmission, or distribution facilities with each other or with one or more other Affiliates, or (ii) otherwise alters DEC's or DEP's obligations with respect to these Regulatory Conditions, absent explicit approval of the Commission.

(c) DEC, DEP, Duke Energy, the other Affiliates, and the Nonpublic Utility Operations shall file notice with the Commission for informational purposes at least 15 days prior to filing with the FERC any agreement, tariff, or other document or any proposed amendments, modifications, or supplements to any such document that has the potential to (i) affect DEC's or DEP's retail cost of service for system power supply resources or transmission system; (ii) reduce the Commission's jurisdiction with respect to transmission planning or any other aspect of the Commission's planning authority; (iii) be interpreted as involving DEC or DEP in joint planning, coordination, dispatch, or operation of generation or transmission facilities with one or more Affiliates; or (iv) otherwise have an Effect on DEC's or DEP's Rates or Service.

(d) Any contract or filing regarding DEC's or DEP's membership in or withdrawal from an RTO or comparable entity must be contingent upon state regulatory approval. This Regulatory Condition does not apply to Piedmont.

(e) DEC, DEP, and Piedmont shall obtain Commission approval before DEBS is sold, transferred, merged with any other entities, has any ownership interest therein changed, or otherwise changed so that a change of control could occur. This requirement does not apply to any movement of DEBS within the Duke Energy holding company system that does not constitute a change of control.

(f) DEC, DEP, and Piedmont may participate in joint comments and other joint filings with Affiliates only when such participation fully complies with both the letter and the spirit of the Regulatory Conditions. Any filing made by DEBS on behalf of DEC, DEP, or Piedmont must clearly identify DEBS as an agent of DEC, DEP, or Piedmont for purposes of making the filing.

(g) Neither DEC, DEP, Piedmont, Duke Energy, another Affiliate, nor a Nonpublic Utility Operation shall make any assertion or argument either on its own initiative or in support of any other entity's assertions in any forum – whether judicial, administrative, federal, state, or otherwise – with respect to any contract, transaction, or other matter in which DEC, DEP, or Piedmont is involved or proposes to be involved or any contract, transaction, or matter involving or proposed to involve Duke Energy, any other Affiliate, or any Nonpublic Utility Operation that may have an Effect on DEC's, DEP's, or Piedmont's Rates or Service, that any of the following actions exceed the Commission's power, authority or jurisdiction under North Carolina law:

(i) reviewing the reasonableness of any Affiliate commitment entered into or proposed to be entered into by DEC, DEP, or Piedmont, or disallowing the costs of, or imputing revenues related to such commitment to, DEC, DEP, or Piedmont;

(ii) exercising its authority over financings or setting rates based on the capital structure, corporate structure, debt costs, or equity costs that it finds to be appropriate for retail ratemaking purposes;

(iii) reviewing the reasonableness of any commitment entered into or proposed to be entered into by DEC, DEP, or Piedmont to transfer an asset;

(iv) mandating, approving, or otherwise regulating a transfer of assets;

(v) scrutinizing and establishing the value of any asset transfers for the purpose of determining the rates for services rendered to DEC's or DEP's Retail Native Load Customers or Piedmont's Customers; or

(vi) exercising any other lawful authority it may have.

Should any other entity so assert, neither DEC, DEP, Piedmont, Duke Energy, other Affiliates, nor the Nonpublic Utility Operations shall support any such assertion and shall, promptly upon learning of such assertion, advise and consult with the Commission and the Public Staff regarding such assertion.

(h) DEC, DEP, Piedmont, Duke Energy, other Affiliates, and the Nonpublic Utility Operations shall (A) acknowledge the risk of any possible preemptive effects of Federal Law with respect to any contract, transaction, or commitment entered into or made or proposed to be entered into or made by DEC, DEP, or Piedmont, or which may otherwise affect DEC's, DEP's, or Piedmont's operations, service, or rates and (B) shall take all actions as may be reasonably necessary and appropriate to hold North Carolina ratepayers harmless from rate increases, foregone opportunities for rate decreases or any other adverse effects of such preemption.

3.10 FERC Filings and Orders. In addition to the filing requirements of Commission Rule R8-27 and all other applicable statutes and rules, and to keep the Commission informed of their activities, DEC and DEP shall, on a quarterly basis, file with the Commission the following: (a) a list of all active dockets at the FERC, including a sufficient description to identify the type of proceeding, in which DEC, DEP, Duke Energy, or DEBS is a party, with new information in each quarterly filing tracked; and (b) a list of the periodic reports filed by DEC, DEP, Duke Energy, or DEBS with the FERC, including sufficient information to identify the subject matter of each report and how each report can be accessed. These filings shall be made in Docket Nos. E-7, Sub 1100E, and E-2, Sub 1095E, as appropriate, and updated regularly. In addition, DEC and DEP shall serve on the Public Staff all filed cost-based and market-based wholesale agreements and amendments; all filings related to their Joint Open Access Transmission Tariff; interconnection agreements and amendments; and any other filings made with the FERC, to the extent these other filings are reasonably likely to have an Effect on DEC's or DEP's Rates or Service. This Regulatory Condition does not apply to Piedmont, as relevant FERC-related information is required to be filed with the Commission in annual gas cost prudence reviews.

SECTION IV
JOINT DISPATCH

The Regulatory Conditions in Section IV do not apply to Piedmont. They are intended to prevent the jurisdiction and authority of the Commission from being preempted as a result of the JDA, to ensure that DEC's and DEP's Retail Native Load Customers receive adequate benefits from the JDA, and to ensure that both joint dispatch costs and the sharing of cost savings can be appropriately audited. The Regulatory Conditions set forth in Section III and the Regulatory Conditions in Section V to the extent they are relevant to Affiliate Contracts also apply to the JDA.

4.1 Conditional Approval and Notification Requirement. DEC and DEP acknowledge that the Commission's approval of the merger between Duke Energy and Progress Energy, and the transfer of dispatch control from DEP to DEC for purposes of implementing the JDA and any successor document is conditioned upon the JDA or successor document never being interpreted as providing for or requiring: (a) a single integrated electric system, (b) a single

BAA, control area or transmission system, (c) joint planning or joint development of generation or transmission, (d) DEC or DEP to construct generation or transmission facilities for the benefit of the other, (e) the transfer of any rights to generation or transmission facilities from DEC or DEP to the other, or (f) any equalization of DEC's and DEP's production costs or rates. If, at any time, DEC, DEP or any other Affiliate learns that any of the foregoing interpretations are being considered, in whatever forum, they shall promptly notify and consult with the Commission and the Public Staff regarding appropriate action.

4.2 Advance Notice Required. To the extent that DEC and DEP desire to engage in any of items (a) through (f) listed in Regulatory Condition 4.1, above, DEC and DEP shall file advance notice with the Commission at least 30 days prior to taking any action to amend the JDA or a successor document or to enter into a separate agreement. The provisions of Regulatory Condition 13.2 shall apply to an advance notice filed pursuant to this Regulatory Condition.

4.3 Function in DEC or DEP. The joint dispatch function, as provided in the JDA or in a successor document, shall be performed by employees of either DEC or DEP.

4.4 No Limitation on Obligations. DEC and DEP acknowledge that nothing in the JDA or any successor document is intended to alter DEC's and DEP's public utility obligations under North Carolina law or to provide for joint dispatch in a fashion that is inconsistent with those obligations, including, without limitation, the following: (a) DEC's obligation to plan for and provide least cost electric service to its Retail Native Load Customers and DEP's obligation to plan for and provide least cost electric service to its Retail Native Load Customers; (b) DEC's obligation to serve its Retail Native Load Customers with the lowest cost power it can reasonably generate or purchase from other sources, before making power available for Non-Native Load Sales; and (c) DEP's obligation to serve its Retail Native Load Customers with the lowest cost power it can reasonably generate or purchase from other sources, before making power available for Non-Native Load Sales.

4.5 Protection of Retail Native Load Customers. All joint dispatch and other activities pursuant to the JDA or successor document shall be performed in such a manner as to (a) ensure the reliable fulfillment of DEC's and DEP's respective service obligations to their Retail Native Load Customers, (b) fulfill each utility's obligation to serve its own Retail Native Load Customers with its lowest cost generation; and (c) minimize the total costs incurred by DEC and DEP to fulfill their respective obligations to their Retail Native Load Customers. In no event shall any Non-Native Load Sales be made if, based upon information known, anticipated, or reasonably available at the time a sale is made, any such sale results in higher fuel and fuel-related costs or non-fuel O&M costs, on a replacement cost basis, than would otherwise have been incurred unless the revenues credited from each such sale more than offset the higher costs.

4.6 Treatment of Costs and Savings. DEC's and DEP's respective fuel and fuel-related costs and non-fuel O&M costs, and the treatment of savings for retail ratemaking purposes, shall be calculated as provided in the JDA, unless explicitly changed by order of the Commission.

4.7 Required Records. DEC and DEP shall keep records related to the JDA or any successor document as prescribed by the Commission and in such detail as may be necessary to enable the Commission and the Public Staff to audit both the actual joint dispatch costs and the sharing of cost savings.

4.8 Auditing of Negative Margins. DEC and DEP also shall keep records that provide such detail as may be necessary to enable the Commission and the Public Staff to audit the circumstances that cause any negative margin on a Non-Native Load Sale or a negative transfer payment made pursuant to Section 7.5(a)(ii) of the JDA.

4.9 Protection of Commission's Authority. Neither DEC, DEP, nor any Affiliate shall assert in any forum – whether judicial, administrative, federal, state, local or otherwise – either on its own initiative or in support of any other entity's assertions that any aspect of the JDA or successor document is intended to diminish or alter the jurisdiction or authority of the Commission over DEC or DEP, including, among other things, the jurisdiction and authority of the Commission to do the following: (a) establish the retail rates on a bundled basis for DEC or DEP, (b) to impose regulatory accounting and reporting requirements, (c) impose service quality standards, (d) require DEC and DEP to engage separately in least cost integrated resource planning, and (e) issue certificates of public convenience and necessity for new generating and transmission resources.

4.10 Preventive Action Required. DEC, DEP, Duke Energy, and other Affiliates shall take all necessary actions to prevent the generating facilities owned or controlled by DEC or DEP from being considered by the FERC to be (a) part, or all, of a power pool, (b) sufficiently integrated to be one integrated system, or (c) otherwise fully subject to the FERC's jurisdiction, as the result of DEC's and DEP's participation in the JDA or any successor document.

4.11 Modification and Termination. DEC and DEP shall modify or terminate the JDA if at any time following consummation of the Merger the Commission finds, after notice and opportunity to be heard, that the JDA does not produce overall cost savings for, or is otherwise not in the best interests of, the North Carolina ratepayers of both DEC and DEP.

4.12 Hold Harmless Commitment. DEC and DEP shall take all actions as may be reasonably appropriate and necessary to hold North Carolina retail ratepayers harmless from any adverse rate impacts related to the JDA, including any trapped costs resulting from actions taken or required by the FERC with respect to the JDA.

SECTION V
TREATMENT OF AFFILIATE COSTS AND RATEMAKING

The following Regulatory Conditions are intended to ensure that the costs incurred by DEC, DEP, and Piedmont are properly incurred, accounted for, and directly charged, directly assigned, or allocated to their respective North Carolina retail operations and that only costs that produce benefits for DEC's and DEP's respective Retail Native Load Customers and Piedmont's Customers are included in DEC's, DEP's, and Piedmont's North Carolina cost of service for ratemaking purposes. The procedures set forth in Regulatory Condition 13.2 do not apply to an advance notice filed pursuant to this section.

5.1 Access to Books and Records. In accordance with North Carolina law, the Commission and the Public Staff shall continue to have access to the books and records of DEC, DEP, Piedmont, Duke Energy, other Affiliates, and the Nonpublic Utility Operations.

5.2 Procurement or Provision of Goods and Services by DEC, DEP, or Piedmont from or to Affiliates or Nonpublic Utility Operations. Except as to transactions between and among DEC, DEP, and Piedmont pursuant to filed and approved service agreements and lists of services, and subject to additional provisions set forth in the Code of Conduct, DEC, DEP, and Piedmont shall take the following actions in connection with procuring goods and services for their respective utility operations from Affiliates or Nonpublic Utility Operations and providing goods and services to Affiliates or Nonpublic Utility Operations:

(a) DEC, DEP, and Piedmont each shall seek out and buy all goods and services from the lowest cost qualified provider of comparable goods and services, and shall have the burden of proving that any and all goods and services procured from their Utility Affiliates, Non-Utility Affiliates, and Nonpublic Utility Operations have been procured on terms and conditions comparable to the most favorable terms and conditions reasonably available in the relevant market, which shall include a showing that comparable goods or services could not have been procured at a lower price from qualified non-Affiliate sources or that DEC, DEP, or Piedmont could not have provided the services or goods for itself on the same basis at a lower cost. To this end, no less than every four years DEC, DEP, and Piedmont shall perform comprehensive non-solicitation based assessments at a functional level of the market competitiveness of the costs for goods and services they receive from a Utility Affiliate, DEBS, another Non-Utility Affiliate, and a Nonpublic Utility Operation, including periodic testing of services being provided internally or obtained individually through outside providers. To the extent the Commission approves the procurement or provision of goods and services between or among DEC, DEP, Piedmont, and the Utility Affiliates, those goods and services may be provided at the supplier's Fully Distributed Cost.

(b) To the extent they are allowed to provide such goods and services, DEC, DEP, and Piedmont shall have the burden of proving that all goods and services provided by any one of them to Duke Energy, a Non-Utility Affiliate, any other Affiliate, or a Nonpublic Utility Operation have been provided on the terms and conditions comparable to the most favorable terms and conditions reasonably available in the market, which shall include a showing that such goods or services have been provided at the higher of cost or market price. To this end, no less than every four years DEC, DEP, and Piedmont shall perform comprehensive, non-solicitation based assessments at a functional level of the market competitiveness of the costs for goods and services provided by either of them to a Utility Affiliate, DEBS, another Non-Utility Affiliate, any other Affiliate, and a Nonpublic Utility Operation.

(c) The periodic assessments required by subdivisions (a) and (b) of this subsection may take into consideration qualitative as well as quantitative factors. To the extent that comparable goods or services provided to DEC, DEP or Piedmont, or by DEC, DEP or Piedmont are not commercially available, this Regulatory Condition shall not apply.

5.3 Location of Core Utility Functions.

(a) This Regulatory Condition does not apply to Piedmont.

(b) Core utility functions are those functions related to Electric Services. The employees performing these core utility functions will be DEC or DEP employees and not service company employees of DEBS. Core utility functions do not include services of a governance or corporate type nature that have been traditionally provided by a service company, the specific services listed on the service company agreement services list for DEC and DEP filed with the Commission pursuant to Regulatory Condition 5.4(a), and roles that provide oversight to the enterprise and are not jurisdiction-specific (Excluded Functions).

(c) All core utility functions employees charging 50% or more of their time to DEC and DEP (separately or combined) should be in the payroll company of either DEC or DEP and not on the payroll of an Affiliate such as DEBS. If it is not readily determinable that a particular function is related to the provision of Electric Services or is an Excluded Function, the appropriate payroll company decision will be governed by whether 50% or more of the affected group or individual employee's time is charged to DEC or DEP.

(d) DEC and DEP shall annually review core utility function employees charging more than 50% of their time to DEC and DEP (separately or combined) over a six-month period from January 1 to June 30. If DEC and DEP determine that an employee performing a core utility function is direct charging 50% or more of his or her time to DEC or DEP, that employee should be transferred to DEC or DEP (if not already on the DEC or DEP payroll). Conversely, if a DEC or DEP employee is charging less than 50% of his or her time to DEC or DEP (separately or combined), and the employee is not otherwise charging the larger portion of their time to DEC or DEP, that employee should not be on the payroll of DEC or DEP.

(e) DEC and DEP shall annually file, at least 90 days prior to January 1, a report containing the results of the annual review and advance notice of any transfers from DEC to DEP to another entity based on direct charging results (Employee Payroll Transfer Report). New organizations and reorganizations will be reflected in the Employee Payroll Transfer Reports.

(f) If an employee transfer from DEC or DEP occurs during the middle of the year, and that transfer involves the transfer of a core utility function to the service company, the provisions of Regulatory Condition 10.1 will apply.

(g) DEC and DEP may file a list of employees at the higher levels of management (not including those levels of management that report directly to the Chief Executive

Officer for Duke Energy) for their core utility functions that they propose to be DEBS employees in their annual filing.

5.4 Service Agreements and Lists of Services.

(a) DEC, DEP, and Piedmont shall file pursuant to G.S. 62-153 final proposed service agreements that authorize the provision and receipt of non-power goods or services between and among DEC, DEP, Piedmont, their Affiliates or Nonpublic Utility Operations, the list(s) of goods and services that DEC, DEP, and Piedmont each intend to take from DEBS, the list(s) of goods and services DEC, DEP, and Piedmont intend to take from each other and the Utility Affiliates, and the basis for the determination of such list(s) and the elections of such services. All such lists that involve payment of fees or other compensation by DEC, DEP, or Piedmont shall require acceptance and authorization by the Commission, and shall be subject to any other Commission action required or authorized by North Carolina law and the Rules and orders of the Commission.

(b) DEC, DEP, and Piedmont shall take goods and services from an Affiliate only in accordance with the filed service agreements and approved list(s) of services. DEC, DEP, and Piedmont shall file notice with the Commission in Docket Nos. E-7, Sub 1100A, E-2, Sub 1095A, and G-6, Sub 682A, respectively, at least 15 days prior to making any proposed changes to the service agreements or to the lists of services.

5.5 Charges for and Allocations of the Costs of Affiliate Transactions. To the maximum extent practicable, all costs of Affiliate transactions shall be directly charged. When not practicable, such costs shall be assigned in proportion to the direct charges. If such costs are of a nature that direct charging and direct assignment are not practicable, they shall be allocated in accordance with Commission-approved allocation methods. The following additional provisions shall apply:

(a) DEC, DEP, and Piedmont shall keep on file with the Commission a cost allocation manual (CAM) with respect to goods or services provided by DEC, DEP, or Piedmont, any Utility Affiliate, DEBS, any other Non-Utility Affiliate, Duke Energy, any other Affiliates, or any Nonpublic Utility Operation to DEC, DEP, or Piedmont. Piedmont will adopt DEC's and DEP's CAM.

(b) The CAM shall describe how all directly charged, direct assignment, and other costs for each provider of goods and services will be charged between and among DEC, DEP, Piedmont, their Utility Affiliates, Non-Utility Affiliates, Duke Energy, any other Affiliates, and the Nonpublic Utility Operations, and shall include a detailed review of the common costs to be allocated and the allocation factors to be used.

(c) The CAM shall be updated annually, and the revised CAM shall be filed with the Commission no later than March 31 of the year that the CAM is to be in effect. DEC, DEP, and Piedmont shall review the appropriateness of the allocation bases every two years, and the results of such review shall be filed with the Commission.

Interim changes shall be made to the CAM, if and when necessary, and shall be filed with the Commission, in accordance with Regulatory Condition 5.6.

(d) No changes shall be made to the procedures for direct charging, direct assigning, or allocating the costs of Affiliate transactions or to the method of accounting for such transactions associated with goods and services (including Shared Services provided by DEBS) provided to or by Duke Energy, other Affiliates, and the Nonpublic Utility Operations until DEC, DEP, or Piedmont has given 15 days' notice to the Commission of the proposed changes, in accordance with Regulatory Condition 5.6.

5.6 Procedures Regarding Interim Changes to the CAM or Lists of Goods and Services for which 15 Days' Notice Is Required. With respect to interim changes to the CAM or changes to lists of goods and services, for which the 15 day notice to the Commission is required, the following procedures shall apply: the Public Staff shall file a response and make a recommendation as to how the Commission should proceed before the end of the notice period. If the Commission has not issued an order within 30 days of the end of the notice period, DEC, DEP, or Piedmont may proceed with the changes but shall be subject to any fully adjudicated Commission order on the matter. The provisions of Regulatory Condition 13.2 do not apply to advance notices filed pursuant to Regulatory Condition 5.5(c) and (d). Such advance notices shall be filed in Docket Nos. E-7, Sub 1100A, E-2, Sub 1095A, and G-9, Sub 682A.

5.7 Annual Reports of Affiliate Transactions. DEC, DEP, and Piedmont shall file annual reports of affiliated transactions with the Commission in a format to be prescribed by the Commission in Docket Nos. E-7, Sub 1100A, E-2, Sub 1095A, and G-9, Sub 682A. The report shall be filed on or before May 30 of each year, for activity through December 31 of the preceding year. DEC, DEP, Piedmont, and other parties may propose changes to the required affiliated transaction reporting requirements and submit them to the Commission for approval, also in Docket Nos. E-7, Sub 1100A, E-2, Sub 1095A, and G-9, Sub 682A.

5.8 Third-party Independent Audits of Affiliate Transactions.

(a) No less often than every two years, a third-party independent audit shall be conducted related to the affiliate transactions undertaken pursuant to Affiliate agreements filed in accordance with Regulatory Condition 5.4 and of DEC's, DEP's, and Piedmont's compliance with all conditions approved by the Commission concerning Affiliate transactions, including the propriety of the transfer pricing of goods and services between or among DEC, DEP, Piedmont, other Affiliates, and all of the Nonpublic Utility Operations.

(i) The first audit shall begin two years from the date of the close of the Merger. It shall include whether DEC's, DEP's, and Piedmont's transactions, services, and other Affiliate dealings pursuant to the regulated utility-to-regulated utility service agreement and any other utility to utility agreements are consistent with all of the conditions related to affiliate dealings and the Code of Conduct and whether DEC, DEP, and Piedmont have operated in accordance with those conditions and Code of Conduct.

(ii) The second audit shall begin two years from the date of the Commission's order on the independent auditor's final report on the first audit or, if no such order is issued, two years from the date of such final report. It shall include whether DEC's, DEP's, and Piedmont's transactions, services, and other Affiliate dealings pursuant to the Service Company Utility Service Agreement and other Affiliate transactions other than transactions undertaken pursuant to regulated utility to regulated utility service agreements are consistent with all of the conditions related to affiliate dealings and the Code of Conduct and whether DEC, DEP, and Piedmont have operated in accordance with those conditions and Code of Conduct.

(iii) Thereafter, independent audits shall occur every two years from the date of the Commission's order on the immediately preceding auditor's final report or, if no such order is issued, two years from the date of such final report. The subject matter of these audits shall alternate between the subject matters for the first and second independent audits. DEC, DEP, and Piedmont may request a change in the frequency of the audit reports in future years, subject to approval by the Commission.

(b) The following further requirements apply:

(i) The independent auditor shall have sufficient access to the books and records of DEC, DEP, Piedmont, Duke Energy, other Affiliates, and all of the Nonpublic Utility Operations to perform the audits.

(ii) For each audit, the Public Staff shall propose one or more independent auditor(s). DEC, DEP, Piedmont, and other parties shall have an opportunity to comment and propose additional auditors. Selection of the independent auditor shall be made by the Commission. Any party proposing an independent auditor shall file such auditor's audit proposal with the Commission.

(iii) The independent auditor shall be supervised in its duties by the Public Staff, and the auditor's reports shall be filed with the Commission.

5.9 Ongoing Review by Commission.

(a) The services rendered by DEC, DEP, and Piedmont to their Affiliates and Nonpublic Utility Operations and the services received by DEC, DEP, or Piedmont from their Affiliates and Nonpublic Utility Operations pursuant to the filed service agreements, the costs and benefits assigned or allocated in connection with such services, and the determination or calculation of the bases and factors utilized to assign or allocate such costs and benefits, as well as DEC's, DEP's, and Piedmont's compliance with the Commission-approved Code of Conduct and all Regulatory Conditions, shall remain subject to ongoing review. These agreements shall be subject to any Commission action required or authorized by North Carolina law and the Rules and orders of the Commission.

(b) The service agreements, the CAM(s) and the assignments and allocations of costs pursuant thereto, the biannual allocation factor reviews required by Regulatory

Condition 5.5(c), the list(s) and the goods and services provided pursuant thereto, and any changes to these documents shall be subject to ongoing Commission review, and Commission action if appropriate.

5.10 Future Orders. For the purposes of North Carolina retail accounting, reporting, and ratemaking, the Commission may, after appropriate notice and opportunity to be heard, issue future orders relating to DEC's, DEP's, or Piedmont's cost of service as the Commission may determine are necessary to ensure that DEC's, DEP's, and Piedmont's operations and transactions with their Affiliates and Nonpublic Utility Operations are consistent with the Regulatory Conditions and Code of Conduct, and with any other applicable decisions of the Commission.

5.11 Review by the FERC. Notwithstanding any of the provisions contained in these Regulatory Conditions, to the extent the allocations adopted by the Commission when compared to the allocations adopted by the other State commissions with ratemaking authority as to a Utility Affiliate of DEC, DEP, or Piedmont result in significant trapped costs related to "non-power goods or administrative or management services provided by an associate company organized specifically for the purpose of providing such goods or services to any public utility in the same holding company system," including DEC, DEP, and Piedmont, DEC, DEP, or Piedmont may request pursuant to Section 1275(b) of Subtitle F in Title XII of PUHCA 2005 that the FERC "review and authorize the allocation of the costs for such goods and services to the extent relevant to that associate company." Such review and authorization shall have whatever effect it is determined to have under the law. The quoted language in this Regulatory Condition is taken directly from Section 1275(b) of Subtitle F in Title XII of PUHCA 2005. The terms "associate company" and "holding company system" are defined in Sections 1262(2) and 1262(9), respectively, of Subtitle F in Title XII of PUHCA 2005 and have the same meanings for purposes of this condition.

5.12 Biannual Review of Certain Transactions by Internal Auditors. Transactions between DEC, DEP, or Piedmont and Duke Energy, other Affiliates, or the Nonpublic Utility Operations, transactions between or among DEC, DEP, and Piedmont, and other transactions between or among Affiliates if such transactions are reasonably likely to have a significant Effect on DEC's, DEP's, or Piedmont's Rates or Service, shall be reviewed at least biannually by Duke Energy's internal auditors. To the extent external audits of the transactions are conducted, DEC, DEP, and Piedmont shall make available such audits for review by the Public Staff and the Commission. DEC, DEP, and Piedmont also shall make available for review by the Public Staff and the Commission all workpapers relating to internal audits and all other internal audit workpapers, if any, related to affiliate transactions, and shall not oppose Public Staff and Commission requests to review relevant external audit workpapers. The requirement to make internal audit workpapers available for review is subject to the assertion of the attorney-client privilege by attorneys for DEC, DEP, and Piedmont. Any dispute as to whether the privilege applies in a particular instance shall be resolved by the Commission in accordance with its regulations and North Carolina law, including the rules of the North Carolina State Bar.

5.13 Notice of Service Company and Non-Utility Affiliates FERC Audits. At such time as DEC, DEP, Piedmont, Duke Energy, or DEBS receives notice from the FERC related to an audit of any Affiliate of DEC, DEP, or Piedmont, DEC, DEP, or Piedmont shall promptly file a notice the Commission that such an audit will be commencing. Any initial report of the FERC's audit team shall be provided to the Public Staff, and any final report shall be filed with the Commission in Docket Nos. E-7, Sub 1100E, E-2, Sub 1095E, and G-9, Sub 682E, respectively.

5.14 Acquisition Adjustment. Any acquisition adjustment that results from the Merger shall be excluded from DEC's, DEP's, and Piedmont's utility accounts and treated for regulatory accounting, reporting, and ratemaking purposes so that it does not affect DEC's or DEP's North Carolina retail rates and charges for Electric Services or Piedmont's North Carolina rates and charges for Natural Gas Services.

5.15 Non-Consummation of Merger. If the Merger is not consummated, neither the cost, nor the receipt, of any termination payment between Duke Energy and Piedmont shall be allocated to DEC, DEP, or Piedmont or recorded on their books. DEC's, DEP's, or Piedmont's Customers shall not otherwise bear any direct expenses or costs associated with a failed merger.

5.16 Protection from Commitments to Wholesale Customers.

(a) This Regulatory Condition does not apply to Piedmont.

(b) For North Carolina retail electric cost of service/ratemaking purposes, DEC's and DEP's respective electric system costs shall be assigned or allocated between and among retail and wholesale jurisdictions based on reasonable and appropriate cost causation principles. For cost of service/ratemaking purposes, North Carolina retail ratepayers shall be held harmless from any cost assignment or allocation of costs resulting from agreements between DEC and the Catawba Joint Owners, and between either DEC or DEP and any of their wholesale customers.

(c) To the extent commitments to DEC's or DEP's wholesale customers relating to the 2012 merger of Duke Energy and Progress Energy are made by or imposed upon DEC or DEP, the effects of which (i) decrease the bulk power revenues that are assigned or allocated to DEC's or DEP's North Carolina retail operations or credited to DEC's or DEP's jurisdictional fuel expenses, (ii) increase DEC's or DEP's North Carolina retail cost of service, or (iii) increase DEC's or DEP's North Carolina retail fuel costs under reasonable cost assignment and allocation practices approved or allowed by the Commission, those effects shall not be recognized for North Carolina retail cost of service or ratemaking purposes.

(d) To the extent that commitments are made by or imposed upon DEC, DEP, Duke Energy, another Affiliate, or a Nonpublic Utility Operation relating to the Merger, either through an offer, a settlement, or as a result of a regulatory order, the effects of which serve to increase the North Carolina retail cost of service or North Carolina retail fuel costs under reasonable cost allocation practices, the effects of these commitments shall not be recognized for North Carolina retail ratemaking purposes.

5.17 Joint Owner-Specific Issues. Assignment or allocation of costs to the North Carolina retail jurisdiction shall not be adversely affected by the manner and amount of recovery of electric system costs from the Catawba Joint Owners as a result of agreements between DEC and the Catawba Joint Owners. This Regulatory Condition does not apply to Piedmont.

5.18 Inclusion of Cost Savings in Future Rate Proceedings. Neither DEC, DEP, Piedmont, Duke Energy, any other Affiliate, nor a Nonpublic Utility Operation shall assert that any interested party is prohibited from seeking the inclusion in future rate proceedings of cost savings that may be realized as a result of any business combination transaction impacting DEC, DEP, and Piedmont.

5.19 Reporting of Costs to Achieve. The North Carolina portion of costs to achieve any business combination transaction savings shall be reflected in DEC's and DEP's North Carolina ES-1 Reports and Piedmont's North Carolina GS-1 Report, as recorded on their books and records under generally accepted accounting principles. DEC, DEP, and Piedmont shall include as a footnote in their ES-1 and GS-1 Reports, as applicable, the Merger-related costs to achieve that were expensed during the relevant period.

5.20 Accounting for Costs to Achieve Related to Historical Events Involving DEP. All costs of Carolina Power and Light Company's merger with North Carolina Natural Gas Company, the Formation of Progress Energy, and Progress Energy's merger with Florida Progress Corporation shall be excluded from DEP's utility accounts, and all direct or indirect corporate cost increases, if any, attributable to those three events shall be excluded from utility costs for all purposes that affect DEP's regulated retail rates and charges. For purposes of this condition, the term "corporate cost increases" means costs in excess of the level DEP would have (a) incurred using prudent business judgment, or (b) had allocated to it, had these transactions not occurred. "Corporate cost increases" also includes any payments made under change-of-control agreements, salary continuation agreements, and other severance- or personnel-type arrangements that are reasonably attributable to these transactions. This Regulatory Condition does not apply to DEC and Piedmont.

5.21 Liabilities of Cinergy Corp. and Florida Progress Corporation.

(a) DEC's and DEP's Retail Native Load Customers and Piedmont's Customers shall be held harmless from all liabilities of Cinergy Corp. and its subsidiaries, including those incurred prior to and after Duke Energy's acquisition of Cinergy Corp. in 2006. These liabilities include, but are not limited to, those associated with the following: (i) manufactured gas plant sites, (ii) asbestos claims, (iii) environmental compliance, (iv) pensions and other employee benefits, (v) decommissioning costs, and (vi) taxes.

(b) DEC's and DEP's Retail Native Load Customers and Piedmont's Customers shall be held harmless from all liabilities of Florida Progress Corporation and its subsidiaries, including those incurred prior to and after Progress Energy's acquisition of Florida Progress Corporation in 2000. These liabilities include, but are not limited to, those associated with the following: (i) any outages at and repairs of Crystal River 3, (ii) manufactured gas plant sites, (iii) asbestos claims, (iv) environmental compliance, (v) pensions and other employee benefits, (vi) decommissioning costs, and (vii) taxes.

(c) DEC's Retail Native Load Customers and Piedmont's Customers shall be held harmless from all current and prospective liabilities of DEP, and DEP's Retail Native Load Customers and Piedmont's Customers shall be held harmless from all current and prospective liabilities of DEC.

5.22 Hold Harmless Commitment. DEC, DEP, Piedmont, Duke Energy, the other Affiliates, and all of the Nonpublic Utility Operations shall take all such actions as may be reasonably necessary and appropriate to hold North Carolina Customers harmless from the effects of the Merger, including rate increases or foregone opportunities for rate decreases, and other effects otherwise adversely impacting Customers.

5.23 Cost of Service Manuals. Within six months after the closing date of the Merger, DEC and DEP shall each file with the Commission revisions to its electric cost of service manual to reflect any changes to the cost of service determination process made necessary by the Merger, any subsequent alterations in the organizational structure of DEC, DEP, Piedmont, Duke Energy, other Affiliates, or the Nonpublic Utility Operations, or other circumstances that necessitate such changes. These filings shall be made in Docket Nos. E-7, Sub 1100A, and E-2, Sub 1095A, respectively. This Regulatory Condition does not apply to Piedmont.

5.24 Direct Charging and Positive Time Reporting for Piedmont. For purposes of distributing the costs of services provided between and among Affiliates, Piedmont will use direct charging and positive time reporting to at least the same extent as DEC and DEP.

5.25 Piedmont Corporate Cost Allocations Among State Jurisdictions. Piedmont will notify the Commission and Public Staff of any plans to modify its corporate cost allocation procedures at least 90 days prior to implementation of the change.

5.26 Allocation of Fully-distributed Costs to Piedmont's Nonpublic Utility Operations. Piedmont shall direct charge or allocate fully distributed costs to its Nonpublic Utility Operations. The fully distributed costs shall include an overhead component for the cost of shared services provided to these non-regulated businesses and equity investments by Piedmont corporate, DEC, DEP, and DEBS employees.

SECTION VI
CODE OF CONDUCT

These Regulatory Conditions include a Code of Conduct in Appendix A. The Code of Conduct governs the relationships, activities and transactions between or among the public utility operations of DEC, DEP, Piedmont, Duke Energy, the Affiliates of DEC, DEP, and Piedmont, and the Nonpublic Utility Operations of DEC, DEP, and Piedmont.

6.1 Obligation to Comply with Code of Conduct. DEC, DEP, Piedmont, Duke Energy, the other Affiliates, and the Nonpublic Utility Operations shall be bound by the terms of the Code of Conduct set forth in Appendix A and as it may subsequently be amended.

SECTION VII
FINANCINGS

The following Regulatory Conditions are intended to ensure (a) that DEC's, DEP's, and Piedmont's capital structures and cost of capital are not adversely affected through their affiliation with Duke Energy, each other, and other Affiliates and (b) that DEC, DEP, and Piedmont have 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.

These conditions do not supersede any orders or directives of the Commission regarding specific securities issuances by DEC, DEP, Piedmont, or Duke Energy. The approval of the Merger by the Commission does not restrict the Commission's right to review, and by order to adjust, DEC's, DEP's, or Piedmont's cost of capital for ratemaking purposes for the effect(s) of the securities-related transactions associated with the Merger.

7.1 Accounting for Equity Investment in Holding Company Subsidiaries. Duke Energy shall maintain its books and records so that any net equity investment in Cinergy Corp. and Progress Energy, their subsidiaries, or their successors, by Duke Energy or any Affiliates can be identified and made available on an ongoing basis. This information shall be provided to the Public Staff upon its request.

7.2 Accounting for Capital Structure Components and Cost Rates. Duke Energy , DEC, DEP, and Piedmont shall keep their respective accounting books and records in a manner that will allow all capital structure components and cost rates of the cost of capital to be identified easily and clearly for each entity on a separate basis. This information shall be provided to the Public Staff upon its request.

7.3 Accounting for Equity Investment in DEC, DEP, and Piedmont. DEC, DEP, and Piedmont shall keep their respective accounting books and records so that the amount of Duke Energy's equity investment in DEC, DEP, and Piedmont can be identified and made available upon request on an ongoing basis. This information shall be provided to the Public Staff upon request.

7.4 Reporting of Capital Contributions. As part of their Commission ES-1 and GS-1 Reports, DEC, DEP, and Piedmont shall include a schedule of any capital contribution(s) received from Duke Energy in the applicable calendar quarter.

7.5 Identification of Long-term Debt Issued by DEC, DEP, or Piedmont. DEC, DEP, and Piedmont shall each identify as clearly as possible long-term debt (of more than one year's duration) that they issue in connection with their regulated utility operations and capital requirements or to replace existing debt.

7.6 Procedures Regarding Proposed Financings.

(a) For all types of financings for which DEC, DEP, or Piedmont (or their subsidiaries) are the issuers of the respective securities, DEC, DEP, or Piedmont (or their subsidiaries) shall request approval from the Commission to the extent required by G.S. 62-160 through G.S. 62-169 and Commission Rule R1-16. Generally, the format of these filings should be consistent with past practices. A "shelf registration" approach (similar to Docket No. E-7, Sub 727) may be requested.

(b) For all types of financings by Duke Energy, other than short-term debt as described in G.S. 62-167, the following shall apply:

(i) On or before January 15 of each year, Duke Energy shall file with the Commission and serve on the Public Staff an advance confidential plan of all securities issuances that it anticipates to occur during that calendar year. The annual confidential plan shall include a description of all financings that Duke Energy reasonably believes may occur during the applicable calendar year. A description for each financing shall include the best estimates of the following: type of security; estimate of cost rate (e.g., interest rate for debt); amount of proceeds; brief description of the purpose/reason for issue; and amount of proceeds, if any, that may flow to DEC, DEP, or Piedmont.

(ii) If at any time material changes to the financing plans included in the filed plan appear likely, Duke Energy shall file a revised 30-day advance confidential plan that specifically addresses such changes with the Commission and serve such notice on the Public Staff.

(iii) At the time of the confidential plan filings identified above, Duke Energy shall also file a non-confidential notice that states that a confidential plan has been filed in compliance with this Regulatory Condition 7.6(b).

(iv) Duke Energy may proceed with equity issuances upon the filing of the confidential plan. However, actual debt issuances shall not occur until 30 days after the advance confidential plan or revised plans are filed. In the event it is not feasible for Duke Energy to file a revised advance confidential plan for a material change 30 days in advance, such plan shall be filed by a date that allows adequate time for review or a debt issuance shall be delayed to allow such review. Prior to the Commission's action on the confidential plan for the year in which the plan is filed, Duke Energy may issue securities authorized under the previous year's plan to the extent such securities were not issued during the previous year.

(v) Within 15 days after the filing of an advance confidential plan or revised plan, the Public Staff shall file a confidential report with the Commission with respect to whether any debt issuances require approval pursuant to G.S. 62-160 through G.S. 62-169 and Commission Rule R1-16 and shall recommend that the Commission issue an order deciding how to proceed. Duke Energy shall have seven days in which to respond to the report. If the Commission determines that any debt issuance requires approval, the Commission shall issue an order requiring the filing of an application and no such issuance shall occur until the Commission approves the application. If the Commission determines that no debt issuance requires approval, the Commission shall issue an order so ruling. At the end of the notice period, Duke Energy may proceed with the debt issuance, but shall be subject to any fully adjudicated Commission order on the matter; provided, however, that nothing herein shall affect the applicability of G.S. 62-170 or other similar provision to such securities or obligations.

(vi) On or before April 15 of each year, Duke Energy shall file with the Commission a report on all financings that were executed for the previous calendar year. The actual reports should include the same information as required above for the advance plans plus the actual issuance costs.

(c) If a filing with the Securities and Exchange Commission or other federal agency will be made in connection with a securities issuance, the notice shall describe such filing(s) and indicate the approximate date on which it would occur.

(d) Securities issuances or financings that are associated with a merger, acquisition, or other business combination shall be filed in conjunction with the information requirements and deadlines stated in Regulatory Conditions 9.1 and 9.2, and this Condition 7.6 shall not apply to such securities issuances or financings.

7.7 Money Pool Agreement. Subject to the limitations imposed in Regulatory Condition 8.5, DEC, DEP, and Piedmont may borrow through Duke Energy's "Utility Money Pool Agreement" (Utility MPA), provided as follows: (a) participation in the Utility MPA is limited to the parties to the Utility MPA filed with the Commission on December 1, 2011, in Docket Nos. E-7, Sub 986A, and E-2, Sub 998A, plus Piedmont and with the exception of the Progress Energy Service Company; and (b) the Utility MPA continues to provide that no loans through the Utility MPA will be made to, and no borrowings through the Utility MPA will be made by, Duke Energy, Progress Energy, and Cinergy Corp.

7.8 Borrowing Arrangements. Subject to the limitations imposed in Regulatory Condition 8.5, DEC, DEP, and Piedmont may borrow short-term funds through one or more joint external debt or credit arrangements (a Credit Facility), provided that the following conditions are met:

(a) No borrowing by DEC, DEP, or Piedmont under a Credit Facility shall exceed one year in duration, absent Commission approval;

(b) No Credit Facility shall include, as a borrower, any party other than Duke Energy, DEC, DEP, Duke Indiana, Duke Kentucky, DEF, Duke Ohio, and Piedmont; and

(c) DEC's, DEP's, and Piedmont's participation in any Credit Facility shall in no way cause either of them to guarantee, assume liability for, or provide collateral for any debt or credit other than its own.

7.9 Long-Term Debt Fund Restrictions. DEC, DEP, and Piedmont shall acquire their respective long-term debt funds through the financial markets, and shall neither borrow from, nor lend to, on a long-term basis, Duke Energy or any of the other Affiliates. To the extent that either DEC, DEP, or Piedmont borrows on short-term or long-term bases in the financial markets and is able to obtain a debt rating, its debt shall be rated under its own name.

SECTION VIII
CORPORATE GOVERNANCE/RING FENCING

The following Regulatory Conditions are intended to ensure the continued viability of DEC, DEP, and Piedmont and to insulate and protect DEC, DEP, and their Retail Native Load Customers and Piedmont and its Customers from the business and financial risks of Duke Energy and the Affiliates within the Duke Energy holding company system, including the protection of utility assets from liabilities of Affiliates.

8.1 Investment Grade Debt Rating. DEC, DEP, and Piedmont shall manage their respective businesses so as to maintain an investment grade debt rating on all of their rated debt issuances with all of the debt rating agencies on all of their rated debt issuances. If DEC's, DEP's, or Piedmont's debt rating falls to the lowest level still considered investment grade at the time, DEC, DEP, or Piedmont shall file written notice to the Commission and the Public Staff within five (5) days of such change and an explanation as to why the downgrade occurred. Within 45 days of such notice, DEC, DEP, or Piedmont shall provide the Commission and the Public Staff with a specific plan for maintaining and improving its debt rating. The Commission, after notice and hearing, may then take whatever action it deems necessary consistent with North Carolina law to protect the interests of DEC's or DEP's Retail Native Load Customers and Piedmont's Customers in the continuation of adequate and reliable service at just and reasonable rates.

8.2 Protection Against Debt Downgrade. To the extent the cost rates of any of DEC's, DEP's, or Piedmont's long-term debt (more than one year) or short-term debt (one year or less) are or have been adversely affected through a ratings downgrade attributable to the Merger, a replacement cost rate to remove the effect shall be used for all purposes affecting any of DEC's North Carolina retail rates and charges, DEP's North Carolina retail rates and charges, and Piedmont's North Carolina rates and charges. This replacement cost rate shall be applicable to all financings, refundings, and refinancings taking place following the change in ratings. This procedure shall be effective through DEC's, DEP's and Piedmont's next respective general rate cases. As part of DEC's, DEP's and Piedmont's next respective general rate cases, any future procedure relating to a replacement cost calculation will be determined. This Regulatory Condition does not indicate a preference for a specific debt rating or preferred stock rating for DEC, DEP, or Piedmont on current or prospective bases.

8.3 Distributions from DEC, DEP, and Piedmont to Holding Company. DEC, DEP, and Piedmont shall limit cumulative distributions paid to Duke Energy subsequent to the Merger to (a) the amount of Retained Earnings on the day prior to the closure of the Merger, plus (b) any future earnings recorded by DEC, DEP, and Piedmont subsequent to the Merger.

8.4 Debt Ratio Restrictions. To the extent any of Duke Energy's external debt or credit arrangements contain covenants restricting the ratio of debt to total capitalization on a consolidated basis to a maximum percentage of debt, Duke Energy shall ensure that the capital structures of both DEC, DEP, and Piedmont individually meet those restrictions.

8.5 Limitation on Continued Participation in Utility Money Pool Agreement and Other Joint Debt and Credit Arrangements with Affiliates. DEC, DEP, and Piedmont may participate in the Utility MPA and any other authorized joint debt or credit arrangement as provided in Regulatory Conditions 7.7 and 7.8 only to the extent such participation is beneficial to DEC's and DEP's respective Retail Native Load Customers and Piedmont's Customers and does not negatively affect DEC's, DEP's, or Piedmont's ability to continue to provide adequate and reliable service at just and reasonable rates.

8.6 Notice of Level of Non-Utility Investment by Holding Company System. In order to enable the Commission to determine whether the cumulative investment by Duke Energy in assets, ventures, or entities other than regulated utilities is reasonably likely to have an Effect on DEC's, DEP's, or Piedmont's Rates or Service so as to warrant Commission action (pursuant to Regulatory Condition 8.8 or other applicable authority) to protect DEC's or DEP's Retail Native Load Customers or Piedmont's Customers, Duke Energy shall notify the Commission within 90 days following the end of any fiscal year for which Duke Energy reports to the Securities and Exchange Commission assets in its operations other than regulated utilities that are in excess of 22% of its consolidated total assets. The following procedures shall apply to such a notice:

(a) Any interested party may file comments within 45 days of the filing of Duke Energy's notice.

(b) If timely comments are filed, the Public Staff shall place the matter on a Commission Staff Conference agenda as soon as possible, but in no event later than 15 days after the comments are filed, and shall make a recommendation as to how the Commission should proceed. If the Commission determines that the percentage of total assets invested in Duke Energy's its operations other than regulated utilities is reasonably likely to have an Effect on DEC's, DEP's, or Piedmont's Rates or Service so as to warrant action by the Commission to protect DEC's and DEP's Retail Native Load Customers and Piedmont's Customers, the Commission shall issue an order setting the matter for further consideration. If the Commission determines that the percentage threshold being exceeded does not warrant action by the Commission, the Commission shall issue an order so ruling.

8.7 Notice by Holding Company of Certain Investments. Duke Energy shall file a notice with the Commission subsequent to Board approval and as soon as practicable following any public announcement of any investment in a regulated utility or a non-regulated business that represents five (5) percent or more of Duke Energy's book capitalization.

8.8 Ongoing Review of Effect of Holding Company Structure. The operation of DEC, DEP, and Piedmont under a holding company structure shall continue to be subject to Commission review. To the extent the Commission has authority under North Carolina law, it may order modifications to the structure or operations of Duke Energy, DEBS, another Affiliate, or a Nonpublic Utility Operation, and may take whatever action it deems necessary in the interest of Retail Native Load Customers and Piedmont's Customers to protect the economic viability of DEC, DEP, and Piedmont, including the protection of DEC's, DEP's, and Piedmont's public utility assets from liabilities of Affiliates.

8.9 Investment by DEC, DEP, or Piedmont in Non-regulated Utility Assets and Non-utility Business Ventures. Neither DEC, DEP, nor Piedmont shall invest in a non-regulated utility asset or any non-utility business venture exceeding $50 million in purchase price or gross book value to DEC, DEP, or Piedmont unless it provides 30 days' advance notice. Regulatory Condition 13.2 shall apply to an advance notice filed pursuant to this Regulatory Condition. Purchases of assets, including land that will be held with a definite plan for future use in providing Electric Services in DEC's or DEP's franchise area or Natural Gas Services in Piedmont's franchise area, shall be excluded from this advance notice requirement.

8.10 Investment by Holding Company in Exempt Wholesale Generators. By April 15 of each year, Duke Energy shall provide to the Commission and the Public Staff a report summarizing Duke Energy's investment in exempt wholesale generators (EWGs) and foreign utility companies (FUCOs) in relation to its level of consolidated retained earnings and consolidated total capitalization at the end of the preceding year. Exempt wholesale generator and foreign utility company are defined in Section 1262(6) of Subtitle F in Title XII of PUHCA 2005 and have the same meanings for purposes of this condition.

8.11 Notice by DEC, DEP, or Piedmont of Default or Bankruptcy of Affiliate. If an Affiliate of DEC, DEP, or Piedmont experiences a default on an obligation that is material to Duke Energy or files for bankruptcy, and such bankruptcy is material to Duke Energy, DEC, DEP, or Piedmont shall notify the Commission in advance, if possible, or as soon as possible, but not later than ten days from such event.

8.12 Annual Report on Corporate Governance. No later than March 31 of each year, DEC, DEP, and Piedmont shall file a report including the following:

(a) A complete, detailed organizational chart (i) identifying DEC, DEP, Piedmont, and each Duke Energy financial reporting segment, and (ii) stating the business purpose of each Duke Energy financial reporting segment. Changes from the report for the immediately preceding year shall be summarized at the beginning of the report.
(b) A list of all Duke Energy financial reporting segment that are considered to constitute non-regulated investments and a statement of each segment's total capitalization and the percentage it represents of Duke Energy's non-regulated investments and total investments. Changes from the report for the immediately preceding year shall be summarized at the beginning of the report.
(c) An assessment of the risks that each unregulated Duke Energy financial reporting segment could pose to DEC, DEP, or Piedmont based upon current business activities of those affiliates and any contemplated significant changes to those activities.

(d) A description of DEC's, DEP's, Piedmont's and each significant Affiliate's actual capital structure. In addition, describe Duke Energy's, DEC's, DEP's, and Piedmont's respective capital structures and plans for achieving such goals.

(e) A list of all protective measures (other than those provided for by the Regulatory Conditions adopted in Docket Nos. E-7, Sub 1100, E-2, Sub 1095, and G-9, Sub 682) in effect between DEC, DEP, Piedmont, and any of their Affiliates, and a description of the goal of each measure and how it achieves that goal, such as mitigation of DEC's, DEP's, and Piedmont's exposure in the event of a bankruptcy proceeding involving any Affiliate(s).

(f) A list of corporate executive officers and other key personnel that are shared between DEC, DEP, Piedmont, and any Affiliate, along with a description of each person's position(s) with, and duties and responsibilities to each entity.

(g) A calculation of Duke Energy's total book and market capitalization as of December 31 of the preceding year for common equity, preferred stock, and debt.

SECTION IX
FUTURE MERGERS AND ACQUISITIONS

The following Regulatory Conditions are intended to ensure that the Commission receives sufficient notice to exercise its lawful authority over proposed mergers, acquisitions, and other business combinations involving Duke Energy, DEC, DEP, Piedmont, other Affiliates, or the Nonpublic Utility Operations. The advance notice provisions set forth in Regulatory Condition 13.2 do not apply to these conditions.

9.1 <u>Mergers and Acquisitions by or Affecting DEC, DEP, or Piedmont</u>. For any proposed merger, acquisition, or other business combination by DEC, DEP, or Piedmont that would have an Effect on DEC's, DEP's, or Piedmont's Rates or Service, DEC, DEP, or Piedmont shall file in a new Sub docket an application for approval pursuant to G S. 62-111(a) at least 180 days before the proposed closing date for such merger, acquisition, or other business combination.

9.2 <u>Mergers and Acquisitions Believed Not to Have an Effect on DEC's, DEP's, or Piedmont's Rates or Service</u>. For any proposed merger, acquisition, or other business combination that is believed not to have an Effect on DEC's, DEP's, or Piedmont's Rates or Service, but which involves Duke Energy, other Affiliates, or the Nonpublic Utility Operations and which has a transaction value exceeding $1.5 billion, the following shall apply:

(a) Advance notification shall be filed with the Commission in a new Sub docket by the merging entities at least 90 days prior to the proposed closing date for such proposed merger, acquisition or other business combination. The advance notification is intended to provide the Commission an opportunity to determine whether the proposed merger, acquisition, or other business combination is reasonably likely to affect DEC, DEP, or Piedmont so as to require approval pursuant to G S. 62-111(a). The notification shall contain sufficient information to enable the Commission to make such a determination. If the Commission determines that such approval is required, the 180-day advance filing requirement in Regulatory Condition 9.1 shall not apply.

(b) Any interested party may file comments within 45 days of the filing of the advance notification.

(c) If timely comments are filed, the Public Staff shall place the matter on a Commission Staff Conference agenda as soon as possible, but in no event later than 15 days after the comments are filed, and shall recommend that the Commission issue an order deciding how to proceed. If the Commission determines that the merger, acquisition, or other business combination requires approval pursuant to G.S. 62-111(a), the Commission shall issue an order requiring the filing of an application, and no closing can occur until and unless the Commission approves the proposed merger, acquisition, or business combination. If the Commission determines that the merger, acquisition, or other business combination does not require approval pursuant to G.S. 62-111(a), the Commission shall issue an order so ruling. At the end of the notice period, if no order has been issued, Duke Energy, any other Affiliate, or the Nonpublic Utility Operation may proceed with the merger, acquisition, or other business combination but shall be subject to any fully-adjudicated Commission order on the matter.

SECTION X
STRUCTURE/ORGANIZATION

The following Regulatory Conditions are intended to ensure that the Commission receives adequate notice of, and opportunity to review and take such lawful action as is necessary and appropriate with respect to, changes to the structure and organization of Duke Energy, DEC, DEP, Piedmont, and other Affiliates, and Nonpublic Utility operations as they may affect Customers.

10.1 Transfer of Services, Functions, Departments, Rights, Assets, or Liabilities. DEC, DEP, and Piedmont shall file notice with the Commission 30 days prior to the initial transfer or any subsequent transfer of any services, functions, departments, rights, obligations, assets, or liabilities from DEC, DEP, or Piedmont to DEBS that (a) involves services, functions, departments, rights, obligations, assets, or liabilities other than those of a governance or corporate type nature that traditionally have been provided by a service company or (b) potentially would have a significant effect on DEC's, DEP's, or Piedmont's public utility operations. The provisions of Regulatory Condition 13.2 apply to an advance notice filed pursuant to this Regulatory Condition.

10.2 Notice and Consultation with Public Staff Regarding Proposed Structural and Organizational Changes. Upon request, DEC, DEP, and Piedmont shall meet and consult with, and provide requested relevant data to, the Public Staff regarding plans for significant changes in DEC's, DEP's, Piedmont's or Duke Energy's organization, structure (including RTO developments), and activities; the expected or potential impact of such changes on Customer rates, operations and service; and proposals for assuring that such plans do not adversely affect DEC's or DEP's Retail Native Load Customers or Piedmont's Customers. To the extent that proposed significant changes are planned for the organization, structure, or activities of an Affiliate or Nonpublic Utility Operation and such proposed changes are likely to have an adverse impact on DEC's, DEP's, or Piedmont's Customers, then DEC's, DEP's, and Piedmont's plans and proposals for assuring that those plans do not adversely affect their Customers must be included in these meetings. DEC, DEP, and Piedmont shall inform the Public Staff promptly of any such events and changes.

SECTION XI
SERVICE QUALITY

The following Regulatory Conditions are intended to ensure that DEC, DEP, and Piedmont continue to implement and further their commitment to providing superior public utility service by meeting recognized service quality indices and implementing the best practices of each other and their Utility Affiliates, to the extent reasonably practicable.

11.1 Overall Service Quality. Upon consummation of the Merger, DEC, DEP, and Piedmont each shall continue their commitment to providing superior public utility service and shall maintain the overall reliability of Electric Services and Natural Gas Services at levels no less than the overall levels it has achieved in the past decade.

11.2 Best Practices. DEC, DEP, and Piedmont shall make every reasonable effort to incorporate each other's best practices into its own practices to the extent practicable.

11.3 Quarterly Reliability Reports. DEC and DEP shall each provide quarterly service reliability reports to the Public Staff on the following measures: System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI).

11.4 Notice of NERC Audit. This Regulatory Condition does not apply to Piedmont. At such time as either DEC or DEP receives notice that the North American Electric Reliability Corporation (NERC) or the SERC Reliability Corporation will be conducting a non-routine compliance audit with respect to DEC's or DEP's compliance with mandatory reliability standards, DEC or DEP shall notify the Public Staff.

11.5 Right-of-Way Maintenance Expenditures (DEC and DEP). DEC and DEP shall budget and expend sufficient funds to trim and maintain their lower voltage line rights-of-way and their distribution rights-of-way in a manner consistent with their internal right-of-way clearance practices and Commission Rule R8-26. In addition, DEC and DEP shall track annually, on a major category basis, departmental or division budget requests, approved budgets and actual expenditures for right-of-way maintenance.

11.6 Right-of-Way Maintenance Expenditures (Piedmont). Piedmont shall budget and expend sufficient funds to maintain its pipeline rights-of-way so as to allow ready access by personnel and vehicles for the purpose of responding to pipeline damage, conducting leak and corrosion surveys, performing maintenance activities, and ensuring system integrity, safety, and reliability.

11.7 Right-of-Way Clearance Practices (DEC and DEP). DEC and DEP shall each provide a copy of their internal right-of-way clearance practices to the Public Staff, and shall promptly notify the Public Staff of any significant changes or modifications to the practices or maintenance schedules.

11.8 Right-of-Way Clearance Practices (Piedmont). Piedmont shall provide a copy of its Operating and Maintenance Manual to the Public Staff and shall promptly notify the Public Staff in writing of any substantive changes to Section 9, "Right-of-Way Management Program."

11.9 Meetings with Public Staff.

(a) DEC, DEP, and Piedmont shall each meet annually with the Public Staff to discuss service quality initiatives and results, including (i) ways to monitor and improve service quality, (ii) right-of-way maintenance practices, budgets, and actual expenditures, and (iii) plans that could have an effect on customer service, such as changes to call center operations.

(b) DEC, DEP, and Piedmont shall each meet with the Public Staff at least annually to discuss potential new tariffs, programs, and services that enable its customers to appropriately manage their energy bills based on the varied needs of their customers.

11.10 Customer Access to Service Representatives and Other Services. DEC, DEP, and Piedmont shall continue to have knowledgeable and experienced customer service representatives available 24 hours a day to respond to service outage calls and during normal business hours to handle all types of customer inquiries. DEC, DEP, and Piedmont shall also maintain up-to-date and user-friendly online services and automated telephone service 24 hours a day to perform routine customer interactions and to provide general billing and customer information.

11.11 Customer Surveys. DEC, DEP, and Piedmont shall continue to survey their customers regarding their satisfaction with public utility service and shall incorporate this information into their processes, programs, and services.

SECTION XII
TAX MATTERS

The following Regulatory Conditions are intended to ensure that DEC's, DEP's, and Piedmont's North Carolina Customers do not bear any additional tax costs as a result of the Merger and receive an appropriate share of any tax benefits associated with the service company Affiliates.

12.1 Costs under Tax Sharing Agreements. Under any tax sharing agreement, DEC, DEP, and Piedmont shall not seek to recover from North Carolina Customers any tax costs that exceed DEC's, DEP's, or Piedmont's tax liability calculated as if it were a stand-alone, taxable entity for tax purposes.

12.2 Tax Benefits Associated with Service Companies. The appropriate portion of any income tax benefits associated with DEBS shall accrue to the North Carolina retail operations of DEC, DEP, and Piedmont, respectively, for regulatory accounting, reporting, and ratemaking purposes.

SECTION XIII
PROCEDURES

The following Regulatory Conditions are intended to apply to all filings made pursuant to these Regulatory Conditions unless otherwise expressly provided by, Commission order, rule, or statute.

13.1 Filings that Do Not Involve Advance Notice. Regulatory Condition filings that are not subject to Regulatory Condition 13.2 shall be made in sub dockets of Docket Nos. E-7, Sub 1100, E-2, Sub 1095, and G-9, Sub 682, as follows:

(a) Filings related to affiliate matters required by Regulatory Conditions 5.4, 5.5, 5.6, 5.7, and 5.23 and the filing permitted by Regulatory Condition 5.3 shall be made by DEC, DEP, and Piedmont in Subs 1100A, 1095A, and 682A, respectively;
(b) Filings related to financings required by Regulatory Condition 7.6, and the filings required by Regulatory Conditions 8.6, 8.7, 8.10, 8.11 and 8.12 shall be made by DEC, DEP, and Piedmont in Subs 1100B, 1095B, and 682B, respectively;
(c) Files related to compliance as required by Regulatory Condition 14.4 and filings required by Sections III.A.2(k), III.A.3(e), (f), and (g), III.D.5, and III.D.8 of the Code of Conduct shall be made by DEC, DEP, and Piedmont in Subs 1100C, 1095C, and 682C, respectively;
(d) Filings related to the independent audits required by Regulatory Condition 5.8 shall be made in Subs 1100D, 1095D, and 682D, respectively; and
(e) Filings related to orders and filings with the FERC, as required by Regulatory Condition 3.1(d), 3.10 and 5.13 shall be made by DEC, DEP, and Piedmont in Subs 1100E, 1095E, and 682E, respectively.

13.2 Advance Notice Filings. Advance notices filed pursuant to Regulatory Conditions 3.3(b), 4.2, 8.9, and 10.1 shall be assigned a new, separate Sub docket. Such a filing shall identify the condition and notice period involved and state whether other regulatory approvals are required and shall be in the format of a pleading, with a caption, a title, allegations of the activities to be undertaken, and a verification. Advance notices may be filed under seal if necessary. The following additional procedures apply:

(a) Advance notices of activities to be undertaken shall not be filed until sufficient details have been decided upon to allow for meaningful discovery as to the proposed activities.
(b) The Chief Clerk shall distribute a copy of advance notice filings to each Commissioner and to appropriate members of the Commission Staff and Public Staff.

(c) DEC, DEC, or Piedmont shall serve such advance notices on each party to Docket Nos. E-7, Sub 1100, E-2, Sub 1095, and G-9, Sub 682, respectively, that has filed a request to receive them with the Commission within 30 days of the issuance of an order approving the Merger in this docket. These parties may participate in the advance notice proceedings without petitioning to intervene. Other interested persons shall be required to follow the Commission's usual intervention procedures.

(d) To effectuate this Regulatory Condition, DEC, DEP, or Piedmont shall serve pertinent information on all parties at the time it serves the advance notice. During the advance notice period, a free exchange of information is encouraged, and parties may request additional relevant information. If DEC, DEP, or Piedmont objects to a discovery request, DEC, DEP, or Piedmont and the requesting party shall try to resolve the matter. If the parties are unable to resolve the matter, DEC, DEP, or Piedmont may file a motion for a protective order with the Commission.

(e) The Public Staff shall investigate and file a response with the Commission no later than 15 days before the notice period expires. Any other interested party may also file a response or objection within 15 days before the notice period expires. DEC, DEP, or Piedmont may file a reply to the response(s).

(f) The basis for any objection to the activities to be undertaken shall be stated with specificity. The objection shall allege grounds for a hearing, if such is desired.

(g) If neither the Public Staff nor any other party files an objection to the activities within 15 days before the notice period expires, no Commission order shall be issued, and the Sub docket in which the advance notice was filed may be closed.

(h) If the Public Staff or any other party files a timely objection to the activities to be undertaken by DEC, DEP, or Piedmont, the Public Staff shall place the matter on a Commission Staff Conference agenda as soon as possible, but in no event later than two weeks after the objection is filed, and shall recommend that the Commission issue an order deciding how to proceed as to the objection. The Commission reserves the right to extend an advance notice period by order should the Commission need additional time to deliberate or investigate any issue. At the end of the notice period, if no objection has been filed by the Public Staff and no order, whether procedural or substantive, has been issued, DEC, DEP, Piedmont, Duke Energy, any other Affiliate, or the Nonpublic Utility Operation may execute the proposed agreement, proceed with the activity to be undertaken, or both, but shall be subject to any fully-adjudicated Commission order on the matter.

(i) If the Commission schedules a hearing on an objection, the party filing the objection shall bear the burden of proof at the hearing.

(j) The precedential effect of advance notice proceedings, like most issues of res judicata, will be decided on a fact-specific basis.

(k) If some other Commission filing or Commission approval is required by statute, notice pursuant to a Regulatory Condition alone does not satisfy the statutory requirement.

SECTION XIV
COMPLIANCE WITH CONDITIONS AND CODE OF CONDUCT

The following Regulatory Conditions are intended to ensure that Duke Energy, DEC, DEP, Piedmont, and all other Affiliates establish and maintain the structures and processes necessary to fulfill the commitments expressed in all of the Regulatory Conditions and the Code of Conduct in a timely, consistent, and effective manner.

14.1 Ensuring Compliance with Regulatory Conditions and Code of Conduct. Duke Energy, DEC, DEP, Piedmont, and all other Affiliates shall devote sufficient resources into the creation, monitoring, and ongoing improvement of effective internal compliance programs to ensure compliance with all Regulatory Conditions and the DEC/DEP/Piedmont Code of Conduct, and shall take a proactive approach toward correcting any violations and reporting them to the Commission. This effort shall include the implementation of systems and protocols for monitoring, identifying, and correcting possible violations, a management culture that encourages compliance among all personnel, and the tools and training sufficient to enable employees to comply with Commission requirements.

14.2 Designation of Chief Compliance Officer. DEC, DEP, and Piedmont shall designate a chief compliance officer who will be responsible for compliance with the Regulatory Conditions and Code of Conduct. This person's name and contact information must be posted on DEC's, DEP's, and Piedmont's Internet Websites.

14.3 Annual Training. DEC, DEP, and Piedmont shall provide annual training on the requirements and standards contained within the Regulatory Conditions and Code of Conduct to all of their employees (including service company employees) whose duties in any way may be affected by such requirements and standards. New employees must receive such training within the first 60 days of their employment. Each employee who has taken the training must certify electronically or in writing that s/he has completed the training.

14.4 Report of Violations. If DEC, DEP, or Piedmont discover that a violation of their requirements or standards contained within the Regulatory Conditions and Code of Conduct has occurred then DEC, DEP, or Piedmont shall file a statement with the Commission in Docket Nos. E-7, Sub 1100C, E-2, Sub 1095C, and G-9, Sub 682C, respectively, describing the circumstances leading to that violation of DEC's, DEP's, or Piedmont's requirements or standards, as contained within the Regulatory Conditions and Code of Conduct, and the mitigating and other steps taken to address the current or any future potential violation.

SECTION XV
PROCEDURES FOR DETERMINING LONG-TERM SOURCES OF PIPELINE CAPACITY AND SUPPLY

The following Regulatory Conditions are intended to ensure the continued practices of DEC, DEP, and Piedmont for determining long-term sources of pipeline capacity and supply.

ELECTRIC – MISCELLANEOUS

15.1 Cost-benefit Analysis. The appropriate source(s) for the interstate pipeline capacity and supply shall be determined by DEC and DEP on the basis of the benefits and costs of such source(s) specific to their respective electric customers. The appropriate source(s) for the interstate pipeline capacity and supply shall be determined by Piedmont on the basis of the specific benefits and costs of such source(s) specific to its natural gas customers, including electric power generating customers.

15.2 Ownership and Control of Contracts. Piedmont shall retain title, ownership, and management of all gas contracts necessary to ensure the provision of reliable Natural Gas Services consistent with Piedmont's best cost gas and capacity procurement methodology.

CODE OF CONDUCT

GOVERNING THE RELATIONSHIPS, ACTIVITIES, AND TRANSACTIONS BETWEEN AND AMONG THE PUBLIC UTILITY OPERATIONS OF DEC, THE PUBLIC UTILITY OPERATIONS OF DEP, THE PUBLIC UTILITY OPERATIONS OF PIEDMONT, DUKE ENERGY CORPORATION, OTHER AFFILIATES, AND THE NONPUBLIC UTILITY OPERATIONS OF DEC, DEP, AND PIEDMONT

I. DEFINITIONS

For the purposes of this Code of Conduct, the terms listed below shall have the following definitions:

Affiliate: Duke Energy and any business entity of which ten percent (10%) or more is owned or controlled, directly or indirectly, by Duke Energy. For purposes of this Code of Conduct, Duke Energy and any business entity controlled by it are considered to be Affiliates of DEC, DEP, and Piedmont, and DEC, DEP, and Piedmont are considered to be Affiliates of each other.

Commission: The North Carolina Utilities Commission.

Confidential Systems Operation Information or CSOI: Nonpublic information that pertains to Electric Services provided by DEC or DEP, including but not limited to information concerning electric generation, transmission, distribution, or sales, and nonpublic information that pertains to Natural Gas Services provided by Piedmont, including but not limited to information concerning transportation, storage, distribution, gas supply, or other similar information.

Customer: Any retail electric customer of DEC or DEP in North Carolina and any Commission-regulated natural gas sales or natural gas transportation customer of Piedmont located in North Carolina.

Customer Information: Non-public information or data specific to a Customer or a group of Customers, including, but not limited to, electricity consumption, natural gas consumption, load profile, billing history, or credit history that is or has been obtained or compiled by DEC, DEP, or Piedmont in connection with the supplying of Electric Services or Natural Gas Services to that Customer or group of Customers.

ELECTRIC – MISCELLANEOUS

DEBS: Duke Energy Business Services, LLC, and its successors, which is a service company Affiliate that provides Shared Services to DEC, DEP, Piedmont, Duke Energy, other Affiliates, or the Nonpublic Utility Operations of DEC, DEP, or Piedmont, singly or in any combination.

DEC: Duke Energy Carolinas, LLC, the business entity, wholly owned by Duke Energy, that holds the franchise granted by the Commission to provide Electric Services within DEC's North Carolina service territory and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

DEP: Duke Energy Progress. LLC, the business entity, wholly owned by Duke Energy, that holds the franchises granted by the Commission to provide Electric Services within the DEP's North Carolina service territory and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

Duke Energy: Duke Energy Corporation, which is the current holding company parent of DEC, DEP, and Piedmont, and any successor company.

Electric Services: Commission-regulated electric power generation, transmission, distribution, delivery, and sales, and other related services, including, but not limited to, administration of Customer accounts and rate schedules, metering, billing, standby service, backups, and changeovers of service to other suppliers.

Fuel and Purchased Power Supply Services: All fuel for generating electric power and purchased power obtained by DEC or DEP from sources other than DEC or DEP for the purpose of providing Electric Services.

Fully Distributed Cost: All direct and indirect costs, including overheads and an appropriate cost of capital, incurred in providing goods or services to another business entity; provided, however, that (a) for each good or service supplied by DEC, DEP, or Piedmont, the return on common equity utilized in determining the appropriate cost of capital shall equal the return on common equity authorized by the Commission in the supplying utility's most recent general rate case proceeding; (b) for each good or service supplied to DEC, DEP, or Piedmont, the appropriate cost of capital shall not exceed the overall cost of capital authorized in the supplying utility's most recent general rate case proceeding; and (c) for each good or service supplied by DEC, DEP, or Piedmont to each other, the return on common equity utilized in determining the appropriate cost of capital shall not exceed the lower of the returns on common equity authorized by the Commission in DEC's, DEP's, or Piedmont's most recent general rate case proceeding, as applicable.

JDA: Joint Dispatch Agreement, which is the agreement as filed with the Commission in Docket Nos. E-7, Sub 986, and E-2, Sub 998, on June 22, 2011, and as amended and refiled on June 12, 2012.

Market Value: The price at which property, goods, or services would change hands in an arm's length transaction between a buyer and a seller without any compulsion to engage in a transaction, and both having reasonable knowledge of the relevant facts.

Merger: All transactions contemplated by the Agreement and Plan of Merger between Duke Energy and Piedmont.

Natural Gas Services: Commission-regulated natural gas sales and natural gas transportation, and other related services, including, but not limited to, administration of Customer accounts and rate schedules, metering and billing, and standby service.

Non-affiliated Gas Marketer: An entity, not affiliated with DEC, DEP, or Piedmont, engaged in the unregulated sale, arrangement, brokering or management of gas supply, pipeline capacity, or gas storage.

Nonpublic Utility Operations: All business operations engaged in by DEC, DEP, or Piedmont involving activities (including the sales of goods or services) that are not regulated by the Commission or otherwise subject to public utility regulation at the state or federal level.

Non-Utility Affiliate: Any Affiliate, including DEBS, other than a Utility Affiliate, DEC, DEP, or Piedmont.

Personnel: An employee or other representative of DEC, DEP, Piedmont, Duke Energy, another Affiliate, or a Nonpublic Utility Operation, who is involved in fulfilling the business purpose of that entity.

Piedmont: Piedmont Natural Gas Company, Inc., the business entity, wholly owned by Duke Energy, that holds the franchise granted by the Commission to provide Natural Gas Services within its North Carolina service territory and that engages in public utility operations, as defined in G.S. 62-3(23), within the State of North Carolina.

Progress Energy: Progress Energy, Inc., which is the former holding company parent of DEP and is a subsidiary of Duke Energy, and any successors.

Public Staff: The Public Staff of the North Carolina Utilities Commission.

Regulatory Conditions: The conditions imposed by the Commission in connection with or related to the Merger.

Shared Services: The services that meet the requirements of the Regulatory Conditions approved in Docket Nos. E-2, Sub 1095, E-7, Sub 1100, and G-9, Sub 682, or subsequent orders of the Commission and that the Commission has explicitly authorized DEC, DEP, and Piedmont to take from DEBS pursuant to a service agreement (a) filed with the Commission pursuant to G.S. 62-153(b), thus requiring acceptance and authorization by the Commission, and (b) subject to all other applicable provisions of North Carolina law, the rules and orders of the Commission, and the Regulatory Conditions.

Shipper: A Non-affiliated Gas Marketer, a municipal gas customer, or an end-user of gas.

Utility Affiliates: The regulated public utility operations of Duke Energy Indiana, LLC (Duke Indiana), Duke Energy Kentucky, Inc. (Duke Kentucky), Florida Power Corporation, d/b/a Progress Energy Florida, LLC (DEF), and Duke Energy Ohio, Inc. (Duke Ohio).

II. GENERAL

This Code of Conduct establishes the minimum guidelines and rules that apply to the relationships, transactions, and activities involving the public utility operations of DEC, DEP, Piedmont, Duke Energy, other Affiliates, or the Nonpublic Utility Operations of DEC, DEP, and Piedmont, to the extent such relationships, activities, and transactions affect the public utility operations of DEC, DEP, and Piedmont in their respective service areas. DEC, DEP, Piedmont, and the other Affiliates are bound by this Code of Conduct pursuant to Regulatory Condition 6.1 approved by the Commission in Docket Nos. E-2, Sub 1095, E-7, Sub 1100, and G-9, Sub 682. This Code of Conduct is subject to modification by the Commission as the public interest may require, including, but not limited to, addressing changes in the organizational structure of DEC, DEP, Piedmont, Duke Energy, other Affiliates, or the Nonpublic Utility Operations; changes in the structure of the electric industry or natural gas industry; or other changes that warrant modification of this Code.

DEC, DEP, or Piedmont may seek a waiver of any aspect of this Code of Conduct by filing a request with the Commission showing that circumstances in a particular case justify such a waiver.

III. STANDARDS OF CONDUCT

A. Independence and Information Sharing

1. Separation - DEC, DEP, Piedmont, Duke Energy, and the other Affiliates shall operate independently of each other and in physically separate locations to the maximum extent practicable; however, to the extent that the Commission has approved or accepted a service company-to-utility or utility-to-utility service agreement or list, DEC, DEP, Piedmont, Duke Energy, and the other Affiliates may operate as described in the agreement or list on file at the Commission. DEC, DEP, Piedmont, Duke Energy, and each of the other Affiliates shall maintain separate books and records. Each of DEC's, DEP's, and Piedmont's Nonpublic Utility Operations shall maintain separate records from those of DEC's, DEP's, and Piedmont's public utility operations to ensure appropriate cost allocations and any arm's-length-transaction requirements.

2. Disclosure of Customer Information:

   (a) Upon request, and subject to the restrictions and conditions contained herein, DEC, DEP, and Piedmont may provide Customer Information to Duke Energy or another Affiliate under the same terms and conditions that apply to the provision of such information to non-Affiliates. In addition, DEC and DEP may provide Customer Information to their respective Nonpublic Utility Operations under the same terms and conditions that apply to the provision of such information to non-Affiliates.

(b) Except as provided in Section III.A.2.(f), Customer Information shall not be disclosed to any Affiliate or non-affiliated third party without the Customer's consent, and then only to the extent specified by the Customer. Consent to disclosure of Customer Information to Affiliates of DEC, DEP, and Piedmont or to DEC's or DEP's Nonpublic Utility Operations may be obtained by means of written, electronic, or recorded verbal authorization upon providing the Customer with the information set forth in Attachment A; provided, however, that DEC, DEP, and Piedmont retain such authorization for verification purposes for as long as the authorization remains in effect. Written, electronic, or recorded verbal authorization or consent for the disclosure of Piedmont's Customer Information to Piedmont's Nonpublic Utility Operations is not required.

(c) If the Customer allows or directs DEC, DEP, or Piedmont to provide Customer Information to Duke Energy, another Affiliate, or to DEC's or DEP's Nonpublic Utility Operations, then DEC, DEP, or Piedmont shall ask if the Customer would like the Customer Information to be provided to one or more non-Affiliates. If the Customer directs DEC, DEP, or Piedmont to provide the Customer Information to one or more non-Affiliates, the Customer Information shall be disclosed to all entities designated by the Customer contemporaneously and in the same manner.

(d) Section III.A.2.shall be permanently posted on DEC's, DEP's and Piedmont's website(s).

(e) No DEC, DEP, or Piedmont employee who is transferred to Duke Energy or another Affiliate shall be permitted to copy or otherwise compile any Customer Information for use by such entity except as authorized by the Customer pursuant to a signed Data Disclosure Authorization. DEC, DEP, and Piedmont shall not transfer any employee to Duke Energy or another Affiliate for the purpose of disclosing or providing Customer Information to such entity.

(f) Notwithstanding the prohibitions in this Section III.A.2.:

(i) DEC, DEP, and Piedmont may disclose Customer Information to DEBS, any other Affiliate, or a non-affiliated third party without Customer consent to the extent necessary for the Affiliate or non-affiliated third party to provide goods or services to DEC, DEP, or Piedmont and upon the written agreement of the other Affiliate or non-affiliated third-party to protect the confidentiality of such Customer Information. To the extent the Commission approves a list of services to be provided and taken pursuant to one or more utility-to-utility service agreements, then Customer Information may be disclosed pursuant to the foregoing exception to the extent necessary for such services to be performed.

(ii) DEC and DEP may disclose Customer Information to their Nonpublic Utility Operations without Customer consent to the extent necessary for the Nonpublic Utility Operations to provide goods and services to DEC or DEP and upon the written agreement of the Nonpublic Utility Operations to protect the confidentiality of such Customer Information.

(iii) DEC, DEP, and Piedmont may disclose Customer Information to a state or federal regulatory agency or court of competent jurisdiction if required in writing to do so by the agency or court.

(g) DEC, DEP, and Piedmont shall take appropriate steps to store Customer Information in such a manner as to limit access to those persons permitted to receive it and shall require all persons with access to such information to protect its confidentiality.

(h) DEC, DEP, and Piedmont shall establish guidelines for its employees and representatives to follow with regard to complying with this Section III.A.2.

(i) No DEBS employee may use Customer Information to market or sell any product or service to DEC's, DEP's, or Piedmont's Customers, except in support of a Commission-approved rate schedule or program or a marketing effort managed and supervised directly by DEC, DEP, or Piedmont.

(j) DEBS employees with access to Customer Information must be prohibited from making any improper indirect use of the data, including directing or encouraging any actions based on the Customer Information by employees of DEBS that do not have access to such information, or by other employees of Duke Energy or other Affiliates or Nonpublic Utility Operations of DEC and DEP.

(k) Should any inappropriate disclosure of DEC, DEP, or Piedmont Customer Information occur at any time, DEC, DEP, or Piedmont shall promptly file a statement with the Commission describing the circumstances of the disclosure, the Customer information disclosed, the results of the disclosure, and the steps taken to mitigate the effects of the disclosure and prevent future occurrences.

3. The disclosure of Confidential Systems Operation Information of DEC, DEP, and Piedmont shall be governed as follows:

(a) Such CSOI shall not be disclosed by DEC, DEP, or Piedmont to an Affiliate or a Nonpublic Utility Operation unless it is disclosed to all competing non-Affiliates contemporaneously and in the same manner. Disclosure to non-Affiliates is not required under the following circumstances:

(i) The CSOI is provided to employees of DEC or DEP for the purpose of implementing, and operating pursuant to, the JDA in accordance with the Regulatory Conditions approved in Docket Nos. E-7, Sub 986, and E-2, Sub 998.

(ii) The CSOI is necessary for the performance of services approved to be performed pursuant to one or more Affiliate utility-to-utility service agreements.

(iii) A state or federal regulatory agency or court of competent jurisdiction over the disclosure of the CSOI requires the disclosure.

(iv) The CSOI is provided to employees of DEBS pursuant to a service agreement filed with the Commission pursuant to G.S. 62-153.

(v) The CSOI is provided to employees of DEC's, DEP's, or Piedmont's Utility Affiliates for the purpose of sharing best practices and otherwise improving the provision of regulated utility service.

(vi) The CSOI is provided to an Affiliate pursuant to an agreement filed with the Commission pursuant to G.S. 62-153, provided that the agreement specifically describes the types of CSOI to be disclosed.

(vii) Disclosure is otherwise essential to enable DEC or DEP to provide Electric Services to their Customers or for Piedmont to provide Natural Gas Services to its Customers.

(viii) Disclosure of the CSOI is necessary for compliance with the Sarbanes-Oxley Act of 2002.

(b) Any CSOI disclosed pursuant Section III.A.3.(a)(i)-(viii) shall be disclosed only to employees that need the CSOI for the purposes covered by those exceptions and in as limited a manner as possible. The employees receiving such CSOI must be prohibited from acting as conduits to pass the CSOI to any Affiliate(s) and must have explicitly agreed to protect the confidentiality of such CSOI.

(c) For disclosures pursuant to Section III.A.3.(a)(vii) and (viii), DEC, DEP, and Piedmont shall include in their annual affiliated transaction reports the following information:

(i) The types of CSOI disclosed and the name(s) of the Affiliate(s) to which it is being, or has been, disclosed;

(ii) The reasons for the disclosure; and

(iii) Whether the disclosure is intended to be a one-time occurrence or an ongoing process.

To the extent a disclosure subject to the reporting requirement is intended to be ongoing, only the initial disclosure and a description of any processes governing subsequent disclosures need to be reported.

(d) DEC, DEP, Piedmont, and DEBS employees with access to CSOI must be prohibited from making any improper indirect use of the data, including directing or encouraging any actions based on the CSOI by employees that do not have access to such information, or by other employees of Duke Energy or other Affiliates or Nonpublic Utility Operations of DEC, DEP, and Piedmont.

(e) Should the handling or disclosure of CSOI by DEBS, or another Affiliate or Nonpublic Utility Operation, or its respective employees, result in (i) a violation of DEC's or DEP's FERC Statement of Policy and Code of Conduct (FERC Code), 18 CFR 358 - Standards of Conduct for Transmission Providers (Transmission Standards), or any other relevant FERC standards or codes of conduct, (ii) the posting of such data on an Open Access Same-Time Information System (OASIS) or other Internet website, or (iii) other public disclosure of the data, DEC or DEP shall promptly file a statement with the Commission in Docket No. E-7, Sub 1100C, and E-2, Sub 1095C, respectively, describing the circumstances leading to such violation, posting, or other public disclosure describing the circumstances leading to such violation, posting, or other public disclosure, any data required to be posted or otherwise publicly disclosed, and the steps taken to mitigate the effects of the current and prevent any future potential violation, posting, or other public disclosure.

(f) Should any inappropriate disclosure of CSOI occur at any time, DEC, DEP, or Piedmont shall promptly file a statement with the Commission in Docket No. E-7, Sub 1100C, E-2, Sub 1095C, or G-9, Sub 682C, respectively, describing the circumstances of the disclosure, the CSOI disclosed, the results of the disclosure, and the steps taken to mitigate the effects of the disclosure and prevent future occurrences.

(g) Unless publicly noticed and generally available, should the FERC Code, the Transmission Standards, or any other relevant FERC standards or codes of conduct be eliminated, amended, superseded, or otherwise replaced, DEC and DEP shall file a letter with the Commission in Docket Nos. E-7, Sub 1100E, and E-2, Sub 1095E, describing such action within 60 days of the action, along with a copy of any amended or replacement document.

B. Nondiscrimination

1. DEC's, DEP's, and Piedmont's employees and representatives shall not unduly discriminate against non-Affiliated entities.

2. In responding to requests for Electric Services, Natural Gas Services, or both, DEC, DEP, and Piedmont shall not provide any preference to Duke Energy, another Affiliate, or a Nonpublic Utility Operation, or to any customers of such an entity, as compared to non-Affiliates or their customers. Moreover, neither DEC, DEP, Piedmont, Duke Energy, nor any other Affiliates shall represent to any person or entity that Duke Energy, another Affiliate, or a Nonpublic Utility Operation will receive any such preference.

3. DEC, DEP, and Piedmont shall apply the provisions of their respective tariffs equally to Duke Energy, the other Affiliates, the Nonpublic Utility Operations, and non-Affiliates.

4. DEC, DEP, and Piedmont shall process all similar requests for Electric Services, Natural Gas Services, or both, in the same timely manner, whether requested on behalf of Duke Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated entity.

5. No personnel or representatives of DEC, DEP, Piedmont, Duke Energy, or another Affiliate shall indicate, represent, or otherwise give the appearance to another party that Duke Energy or another Affiliate speaks on behalf of DEC, DEP, or Piedmont; provided however, that this prohibition shall not apply to employees of DEBS providing Shared Services or to employees of another Affiliate to the extent explicitly provided for in an affiliate agreement that has been accepted by the Commission. In addition, no personnel or representatives of a Nonpublic Utility Operation shall indicate, represent, or otherwise give the appearance to another party that they speak on behalf of DEC's or DEP's regulated public utility operations.

6. No personnel or representatives of DEC, DEP, Piedmont, Duke Energy, another Affiliate, or a Nonpublic Utility Operation shall indicate, represent, or otherwise give the appearance to another party that any advantage to that party with regard to Electric Services or Natural Gas Services exists as the result of that party dealing with Duke Energy, another Affiliate, or a Nonpublic Utility Operation, as compared with a non-Affiliate.

7. DEC, DEP, and Piedmont shall not condition or otherwise tie the provision or terms of any Electric Services or Natural Gas Services to the purchasing of any goods or services from, or the engagement in business of any kind with, Duke Energy, another Affiliate, or a Nonpublic Utility Operation.

8. When any employee or representative of DEC or DEP receives a request for information from or provides information to a Customer about goods or services available from Duke Energy, another Affiliate, or a Nonpublic Utility Operation, the employee or representative shall advise the Customer that such goods or services may also be available from non-Affiliated suppliers.

9. Disclosure of Customer Information to Duke Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated entity shall be governed by Section III.A.2. of this Code of Conduct.

10. Unless otherwise directed by order of the Commission, electric generation shall not receive a priority of use from Piedmont that would supersede or diminish Piedmont's provision of service to its human needs firm residential and commercial customers.

11. Piedmont shall file an annual report with the Commission summarizing all requests or inquiries for Natural Gas Services made by a non-utility generator, Piedmont's response to the request, and the status of the inquiry.

C. Marketing

1. The public utility operations of DEC, DEP, and Piedmont may engage in joint sales, joint sales calls, joint proposals, or joint advertising (a joint marketing arrangement) with their Affiliates and with their Nonpublic Utility Operations, subject to compliance with other provisions of this Code of Conduct and any conditions or restrictions that the Commission may hereafter establish. DEC, DEP, and Piedmont shall not otherwise engage in such joint activities without making such opportunities available to comparable third parties.

2. Neither Duke Energy nor any of the other Affiliates shall use the names or logos of DEC, DEP, or Piedmont in any communications without the following disclaimer:

(a) "[Duke Energy Corporation/Affiliate) is not the same company as [DEC/DEP/Piedmont], and [Duke Energy Corporation/Affiliate) has separate management and separate employees";

(b) "[Duke Energy Corporation/Affiliate] is not regulated by the North Carolina Utilities Commission or in any way sanctioned by the Commission";

(c) "Purchasers of products or services from [Duke Energy Corporation/Affiliate] will receive no preference or special treatment from [DEC/DEP/Piedmont]"; and

(d) "A customer does not have to buy products or services from [Duke Energy Corporation/Affiliate] in order to continue to receive the same safe and reliable electric service from [DEC/DEP] or natural gas service from Piedmont."

3. Nonpublic Utility Operations may not use the names or logos of DEC, DEP, or Piedmont in communications without the following disclaimer:

"[Name of product or service being offered by Nonpublic Utility Operation] is not part of the regulated services offered by [DEC/DEP/Piedmont] and is not in any way sanctioned by the North Carolina Utilities Commission."

4. In addition, DEC's and DEP's Nonpublic Utility Operations may not use the names or logos of DEC or DEP in any communications without the following disclaimers:

(a) "Purchasers of [name of product or service being offered by Nonpublic Utility Operation] from [Nonpublic Utility Operation] will receive no preference or special treatment from [DEC/DEP]"; and

(b) "A customer does not have to buy this product or service from [Nonpublic Utility Operation] in order to continue to receive the same safe and reliable electric service from [DEC/DEP]."

The required disclaimers in this Section III.C.4. must be sized and displayed in a way that is commensurate with the name and logo so that the disclaimer is at least the larger of one-half the size of the type that first displays the name and logo or the predominant type used in the communication.

D. Transfers of Goods and Services, Transfer Pricing, and Cost Allocation

1. Cross-subsidies involving DEC, DEP, or Piedmont and Duke Energy, other Affiliates, or the Nonpublic Utility Operations are prohibited.

2. All costs incurred by personnel or representatives of DEC, DEP, or Piedmont for or on behalf of Duke Energy, other Affiliates, or the Nonpublic Utility Operations shall be charged to the entity responsible for the costs.

3. The following conditions shall apply as a general guideline to the transfer prices charged for goods and services, including the use or transfer of personnel, exchanged between and among DEC, DEP, or Piedmont, and Duke Energy, the other Non-Utility Affiliates, and the Nonpublic Utility Operations, to the extent such prices affect DEC's, DEP's, or Piedmont's operations or costs of utility service:

(a) Except as otherwise provided for in this Section III.D., for untariffed goods and services provided by DEC, DEP, or Piedmont to Duke Energy, a Non-Utility Affiliate, or a Nonpublic Utility Operation, the transfer price paid to

DEC, DEP, or Piedmont shall be set at the higher of Market Value or DEC's, DEP's, or Piedmont's Fully Distributed Cost.

(b) Except as otherwise provided for in this Section III.D., for goods and services provided, directly or indirectly, by Duke Energy, a Non-Utility Affiliate other than DEBS, or a Nonpublic Utility Operation to DEC, DEP, or Piedmont, the transfer price(s) charged by Duke Energy, the Non-Utility Affiliate, and the Nonpublic Utility Operation to DEC, DEP, or Piedmont shall be set at the lower of Market Value or Duke Energy's, the Non-Utility Affiliate's, or the Nonpublic Utility Operation's Fully Distributed Cost(s). If DEC, DEP, or Piedmont do not engage in competitive solicitation and instead obtain the goods or services from Duke Energy, a Non-Utility Affiliate, or a Nonpublic Utility Operation, DEC, DEP, and Piedmont shall implement adequate processes to comply with this Code provision and related Regulatory Conditions and ensure that in each case DEC's, DEP's, and Piedmont's Customers receive service at the lowest reasonable cost, unless otherwise directed by order of the Commission. For goods and services provided by DEBS to DEC, DEP, Piedmont, and Utility Affiliates, the transfer price charged shall be set at DEBS' Fully Distributed Cost.

(c) Tariffed goods and services provided by DEC, DEP, and Piedmont to Duke Energy, other Affiliates, or a Nonpublic Utility Operation shall be provided at the same prices and terms that are made available to Customers having similar characteristics with regard to Electric Services or Natural Gas Services under the applicable tariff.

(d) With the exception of gas supply transactions, transportation transactions, or both, between DEC and Piedmont or DEP and Piedmont, untariffed non-power, non-generation, or non-fuel goods and services provided by DEC, DEP, or Piedmont to DEC, DEP, Piedmont, or the Utility Affiliates or by the Utility Affiliates to DEC, DEP, or Piedmont, shall be transferred at the supplier's Fully Distributed Cost, unless otherwise directed by order of the Commission.

(e) All Piedmont deliveries to DEC and DEP pursuant to intrastate negotiated sales or transportation arrangements and combinations of sales and transportation transactions shall be at the same price and terms that are made available to other Shippers having comparable characteristics, such as nature of service (firm or interruptible, sales or transportation), pressure requirements, nature of load (process/heating/electric generation), size of load, profile of load (daily, monthly, seasonal, annual), location on Piedmont's system, and costs to serve and rates. Piedmont shall maintain records in sufficient detail to demonstrate compliance with this requirement.

(f) All gas supply transactions, interstate transportation and storage transactions, and combinations of these transactions, between DEC or DEP and Piedmont shall be at the fair market value for similar transactions between non-affiliated third parties. DEC, DEP, and Piedmont shall maintain records, such as published market price indices, in sufficient detail to demonstrate compliance with this requirement.

(g) All of the margins, also referred to as net compensation, received by Piedmont on secondary market sales to DEC and DEP shall be recorded in Piedmont's Deferred Gas Cost Accounts and shall flow through those accounts for the benefit of ratepayers. None of the margins on secondary market sales by Piedmont to DEC and DEP shall be included in the secondary market transactions subject to the sharing mechanism on secondary market transactions approved by the Commission in its Order Approving Stipulation, dated December 22, 1995, in Docket No. G-100, Sub 67. The sharing percentage on secondary market sales shall not be considered in determining the prudence of such transactions.

4. To the extent that DEC, DEP, Piedmont, Duke Energy, other Affiliates, or the Nonpublic Utility Operations receive Shared Services from DEBS (or its successor), these Shared Services may be jointly provided to DEC, DEP, Piedmont, Duke Energy, other Affiliates, or the Nonpublic Utility Operations on a fully distributed cost basis, provided that the taking of such Shared Services by DEC, DEP, and Piedmont is cost beneficial on a service-by-service (e.g., accounting management, human resources management, legal services, tax administration, public affairs) basis to DEC, DEP, and Piedmont. Charges for such Shared Services shall be allocated in accordance with the cost allocation manual filed with the Commission pursuant to Regulatory Condition 5.5, subject to any revisions or other adjustments that may be found appropriate by the Commission on an ongoing basis.

5. DEC, DEP, Piedmont, and their Utility Affiliates may capture economies-of-scale in joint purchases of goods and services (excluding the purchase of electricity or ancillary services intended for resale unless such purchase is made pursuant to a Commission-approved contract or service agreement), if such joint purchases result in cost savings to DEC's, DEP's, and Piedmont's Customers. DEC, DEP, Piedmont, and their Utility Affiliates may capture economies-of-scale in joint purchases of coal and natural gas, if such joint purchases result in cost savings to DEC's, DEP's, and Piedmont's Customers. All joint purchases entered into pursuant to this section shall be priced in a manner that permits clear identification of each participant's portion of the purchases and shall be reported in DEC's, DEP's, and Piedmont's affiliated transaction reports filed with the Commission.

6. All permitted transactions between DEC, DEP, Piedmont, Duke Energy, other Affiliates, and the Nonpublic Utility Operations shall be recorded and accounted for in accordance with the cost allocation manual required to be filed with the Commission pursuant to Regulatory Condition 5.5 and with Affiliate agreements accepted by the Commission or otherwise processed in accordance with North Carolina law, the rules and orders of the Commission, and the Regulatory Conditions.

7. Costs that DEC, DEP, and Piedmont incur in assembling, compiling, preparing, or furnishing requested Customer Information or CSOI for or to Duke Energy, other Affiliates, Nonpublic Utility Operations, or non-Affiliates (other than the Customer or the Customer's designated representative or agent) shall be recovered from the requesting party pursuant to Section III.D.3. of this Code of Conduct.

8. Any technology or trade secrets developed, obtained, or held by DEC, DEP, or Piedmont in the conduct of regulated operations shall not be transferred to Duke Energy, another Affiliate, or a Nonpublic Utility Operation without just compensation and the filing of 60-days prior notification to the Commission. DEC, DEP, and Piedmont are not required to provide advance notice for such transfers to each other and may request a waiver of this requirement from the Commission with respect to such transfers to Duke Energy, a Utility Affiliate, a Non-Utility Affiliate, or a Nonpublic Utility Operation. In no case, however, shall the notice period requested be less than 20 business days.

9. DEC, DEP, and Piedmont shall receive compensation from Duke Energy, other Affiliates, and the Nonpublic Utility Operations for intangible benefits, if appropriate.

E. Regulatory Oversight

1. The requirements regarding affiliate transactions set forth in G.S. 62-153 shall continue to apply to all transactions between DEC, DEP, Piedmont, Duke Energy, and the other Affiliates.

2. The books and records of DEC, DEP, Piedmont, Duke Energy, other Affiliates, and the Nonpublic Utility Operations shall be open for examination by the Commission, its staff, and the Public Staff as provided in G.S. 62-34, 62-37, and 62-51.

3. If Piedmont supplies any Natural Gas Services, with the exception of Natural Gas Services provided pursuant to Commission-approved contracts or service agreements, used by either DEC or DEP to generate electricity, DEC or DEP, as applicable, shall file a report with the Commission in its annual fuel and fuel-related cost recovery case demonstrating that the purchase was prudent and the price was reasonable.

4. To the extent North Carolina law, the orders and rules of the Commission, and the Regulatory Conditions permit Duke Energy, an Affiliate, or a Nonpublic Utility Operation to supply DEC, DEP, or Piedmont with Natural Gas Services or other Fuel and Purchased Power Supply Services used by DEC or DEP to provide Electric Services to Customers, and to the extent such Natural Gas Services or other Fuel and Purchased Power Supply Services are supplied, DEC or DEP, as applicable, shall demonstrate in its annual fuel adjustment clause proceeding that each such acquisition was prudent and the price was reasonable.

F. Utility Billing Format

To the extent any bill issued by DEC, DEP, Piedmont, Duke Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated third party includes charges to Customers for Electric Services or Natural Gas Services and non-Electric Services, non-Natural Gas Services, or any combination of such services, from Duke Energy, another Affiliate, a Nonpublic Utility Operation, or a non-Affiliated third party, the charges for Electric Services and Natural Gas Services shall be separated from the charges for any other services included on the bill. Each such bill shall contain language stating that the Customer's Electric Services and Natural Gas Services will not be terminated for failure to pay for any other services billed.

ELECTRIC – MISCELLANEOUS

G. Complaint Procedure

1. DEC, DEP, and Piedmont shall establish procedures to resolve potential complaints that arise due to the relationship of DEC, DEP, and Piedmont with Duke Energy, the other Affiliates, and the Nonpublic Utility Operations. The complaint procedures shall provide for the following:

(a) Verbal and written complaints shall be referred to a designated representative of DEC, DEP, or Piedmont.
(b) The designated representative shall provide written notification to the complainant within 15 days that the complaint has been received.
(c) DEC, DEP, or Piedmont shall investigate the complaint and communicate the results or status of the investigation to the complainant within 60 days of receiving the complaint.
(d) DEC, DEP, and Piedmont shall each maintain a log of complaints and related records and permit inspection of documents (other than those protected by the attorney/client privilege) by the Commission, its staff, or the Public Staff.

2. Notwithstanding the provisions of Section III.G.1., any complaints received through Duke Energy's EthicsLine (or successor), which is a confidential mechanism available to the employees of the Duke Energy holding company system, shall be handled in accordance with procedures established for the EthicsLine.

3. These complaint procedures do not affect a complainant's right to file a formal complaint with the Commission or otherwise communicate with the Commission or the Public Staff regarding a complaint.

H. Natural Gas/Electricity Competition

DEC, DEP and Piedmont shall continue to compete against all energy providers, including each other, to serve those retail customer energy needs that can be legally and profitably served by both electricity and natural gas. The competition between DEC or DEP and Piedmont shall be at a level that is no less than that which existed prior to the Merger. Without limitation as to the full range of potential competitive activity, DEC, DEP and Piedmont shall maintain the following minimum standards:

1. Piedmont will make all reasonable efforts to extend the availability of natural gas to as many new customers as possible.

2. In determining where and when to extend the availability of natural gas, Piedmont will at a minimum apply the same standards and criteria that it applied prior to the Merger.

3. In determining where and when to extend the availability of natural gas, Piedmont will make decisions in accordance with the best interests of Piedmont, rather than the best interest of DEC or DEP.

4. To the extent that either the natural gas industry or the electricity industry is further restructured, DEC, DEP, and Piedmont will undertake to maintain the full level of competition intended by this Code of Conduct subject to the right of DEC, DEP, Piedmont or the Public Staff to seek relief from or modifications to this requirement by the Commission.

CODE OF CONDUCT
ATTACHMENT A

DEC/DEP/PIEDMONT CUSTOMER INFORMATION DISCLOSURE AUTHORIZATION

<u>For Disclosure to Affiliates</u>:

DEC's/DEP's/Piedmont's Affiliates offer products and services that are separate from the regulated services provided by DEC/DEP/Piedmont. These services are not regulated by the North Carolina Utilities Commission. These products and services may be available from other competitive sources.

The Customer authorizes DEC/DEP/Piedmont to provide any data associated with the Customer account(s) residing in any DEC/DEP/Piedmont files, systems or databases **[or specify specific types of data]** to the following Affiliate(s) ________________. DEC/DEP/Piedmont will provide this data on a non-discriminatory basis to any other person or entity upon the Customer's authorization.

<u>For Disclosure to Nonpublic Utility Operations</u>:

DEC/DEP offers optional, market-based products and services that are separate from the regulated services provided by DEC/DEP. These services are not regulated by the North Carolina Utilities Commission. These products and services may be available from other competitive sources.

The Customer authorizes DEC/DEP to use any data associated with the Customer account(s) residing in any DEC/DEP files, systems or databases **[or specify types of data]** for the purpose of offering and providing energy-related products or services to the Customer. DEC/DEP will provide this data on a non-discriminatory basis to any other person or entity upon the Customer's authorization.

DOCKET NO. E-2, SUB 1106
DOCKET NO. E-7, SUB 1113

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:		
Request of Duke Energy Carolinas, Inc., and	)	
Duke Energy Progress, Inc., for Approval of	)	ORDER APPROVING
Waiver of Certain Provisions of Commission	)	RIDER AND GRANTING
Rules R8-66 and R8-67 for Net Metering	)	WAIVER REQUEST
Non-TOU Customers	)	

BY THE COMMISSION: On April 13, 2016, Duke Energy Carolinas, LLC (DEC) and Duke Energy Progress, LLC (DEP), filed a request for approval of waivers of certain provisions of Commission Rules R8-66 and R8-67 for net metering non-TOU demand (NMNTD) customers, pursuant to the Commission's August 21, 2014, *Order Approving REPS And REPS EMF Riders And 2013 REPS Compliance* in Docket No. E-7, Sub 1052. Under the current Net Metering for Renewable Energy Facilities Rider offered by DEC (Rider NM) and DEP (Rider NM-4B), a customer receiving electric service under a schedule other than a time-of-use schedule with demand rates shall provide any Renewable Energy Certificates (RECs) or "green tags" to DEC and DEP at no cost.

On April 23, 2018, DEC and DEP filed a revised waiver request, noting that due to the passage of time, as well as changes resulting from the enactment of S.L. 2017-192, commonly referred to as House Bill 589, the Companies and the Public Staff agreed that it was appropriate to update and re-file this request for Commission consideration based on current information.

The purpose of the requested waiver is to create a mechanism by which RECs produced by NMNTD customers can be transferred or assigned to the utility. As the number of net-metered solar photovoltaic (PV) facilities has increased in recent years, and with the potential for the deployment of up to 50 MW of new net-metered solar PV over the next five years pursuant to HB 589's Solar Rebate provision, a larger number of RECs are being generated and are potentially available to DEC and DEP for compliance with the Renewable Energy and Energy Efficiency Portfolio Standard (REPS).

DEC and DEP propose waiving certain provisions of Commission Rules R8-66 and R8-67 to allow NMNTD customers be exempt from holding individual accounts in the North Carolina Renewable Energy Tracking System (NC-RETS). DEC and DEP will annually upload the total number of RECs provided by NMNTD customers into NC-RETS under two program designations, utilizing generator attributes that are collected and maintained by the respective utility that serves each customer. DEC and DEP request to report HB 589 RECs under a separate project designation, so one program designation will be for HB 589 solar rebate customers and the second program designation will be for non-rebate net-metered customers.

DEC and DEP propose the following specific waivers in order to facilitate this transfer of RECs without placing an undue burden on NMNTD customers:

ELECTRIC – MISCELLANEOUS

1) Requested waivers of Commission Rule R8-66 are:

   a. Registration as a New Renewable Energy Facility and annual registration updates be waived, and each utility will be permitted to retain relevant information on behalf of the NMNTD customers;
   b. Rule R8-66(b)(1): NMNTD customers not be required to file a Registration Statement, and that utilities will collect and maintain the relevant information in a single docket;
   c. Rule R8-66(b)(4) and (5): waive requirement that generation owner certify annually that their facility complies with all federal and state laws, regulations, and rules for the protection of the environment and natural resources. Under Rider NM or Rider NM-4B, DEC and DEP require the participant to verify that the generation complies with all such requirements. There will be a presumption of compliance for NMNTD customers, and the annual certification requirements will be waived;
   d. Rule R8-66(b)(6): Service under Rider NM and Rider NM-4B to NMNTD customers already complies with this section, which requires that RECs sold to an electric supplier not be remarketed or resold for any purpose; and
   e. Rule R8-66(b)(7) and (8): waive requirement that renewable facility owners consent to audits, verify registration statement, and signify that they have authority to submit information to the Commission. DEC and DEP will receive this signed and verified information and retain the right to inspect NMNTD customers' facilities for eligibility, while the Public Staff and the Commission will have full access to DEC's and DEP's records.

2) Requested waivers of Commission Rule R8-67 are:

   a. Rule R8-67(g)(2) and (h)(8): under this rule, solar PV system output with a nameplate capacity of 10 kW or less can be estimated using generally accepted analytical tools. DEC and DEP request that this limit be raised to 20 kW or less for residential NMNTD customers, to match the threshold established by the Commission in its March 31, 2009 Order in Docket No. E-100, Sub 83, related to additional standby and metering charges. For non-residential customers, DEC and DEP request that this limit be raised to 1,000 kW or less; and
   b. Rule R8-67(g)(2): allow the use of a scalable conversion factor for estimating annual generation from program participants, without needing to individually meter each generator for REC generation purposes. This scalable conversion factor will be based on the National Renewable Energy Laboratory's PVWATTS™ software, which provides the average output of solar PV generators in all North Carolina cities and has a suitable level of detail.

DEC and DEP propose applying this scalable conversion factor to estimate historical energy production data for REC issuance back up to two years from the date on which the Commission approves this request or to the date on which the facility came online, whichever is later, pursuant to Rule R8-67(g)(4). DEC and DEP request Commission approval to report the total number of RECs produced by NMNTD customers (either from meter readings or approved estimating tools) on an annual basis. These reports shall be filed with the utility's REPS compliance filings under Commission Rule R8-67(c), and the total number of RECs shall be imported directly to NC-RETS. DEC and DEP will maintain all supporting documentation to validate RECs, and will provide that information to the Public Staff or Commission for review upon request.

DEC and DEP also propose to conduct annual site visits to ensure the accuracy of the scalable conversion factor. These visits will be conducted to a statistically significant number of participating NMNTD customers, verifying that solar installations covered by this waiver request are still operating. A summary of these findings will be included in the REPS compliance filing, and will be used to adjust production estimates of all program participants. Based upon the results of the two years of site visits, DEC and DEP propose including a recommendation as to whether the visits should continue in the REPS compliance filing.

DEC and DEP discussed this report with the Public Staff before initially filing, and again after filing the revised version, to resolve issues and answer questions. The Public Staff is satisfied that the method DEC and DEP propose to select the sites visited annually, and to verify the solar installations continue to be operating, is sufficient. DEC and DEP indicated they will hire a third-party vendor to conduct the visits, and that the number of evaluations will be based upon the number of customers under Rider NM and NM-4B. The evaluations will further be geographically allocated based upon the percentage of participating NMNTD customers in each geographic area. Evaluations will rotate through customers each year, ensuring that if a customer passes a site evaluation, they will be excluded from future evaluations. The utilities provided the following estimates of the number of NMNTD customers as of April 2018.

NMNTD Customers	**DEC**		**DEP**	
Facility Capacity	# of Facilities	Total Capacity (kW AC)	# of Facilities	Total Capacity (kW AC)
<10 kw	2,787	12,566	1,702	8,055
10kW - 20kW	170	2,246	135	1,750
20kW - 100kW	60	2,734	39	1,815
100kW - 1MW	38	12,739	31	11,157
Total	*3,055*	*30,285*	*1,907*	*22,777*

In response to Public Staff data requests, DEC and DEP indicated that they do not have a means by which to measure actual solar production on net-metered customer sites, and that the meter tagged to the billing account is only able to measure net usage. DEC and DEP stated that if the utility had the ability to record or verify actual generation, the utility would rely on the actual production numbers rather than a scalable conversion factor.

The Public Staff noted that under the Commission's Rules and the NC-RETS Operating Procedures, each person or company that registers with NC-RETS for issuance of RECs must establish each renewable energy facility as a separate "project" within NC-RETS. The NC-RETS website provides a list of all such facilities, which helps protect the integrity of RECs issued in NC-RETS by precluding facilities from being registered in more than one registry at a time. If the owner of a facility that is being issued RECs in NC-RETS attempts to register that same facility in another tracking system, the administrator of that other tracking system can check the NC-RETS website to verify whether the facility is already participating in NC-RETS. DEC's and DEP's request for waiver would relieve Rider participants from registering in NC-RETS, thereby potentially reducing the transparency needed to prevent the double-issuance of RECs.

In the Commission's November 15, 2010, *Order Approving Rider and Granting Waiver Request* in Docket No. E-2, Sub 979, the Commission considered a similar waiver request, and in order to address the concern, required DEC and DEP provide certain details for each participating customer to NC-RETS. The Public Staff recommended in this case that DEC and DEP shall provide NC-RETS on a monthly basis with a list of participating customers, including facility location and size. NC-RETS shall post this information on its website in a manner that will facilitate its use by other registries seeking to preclude the double issuance of RECs.

DEC and DEP also noted that implementation of HB 589 has created two additional programs that bear mentioning here; first, *Petition for Approval of Solar Rebate Program* (Dockets E-2, Sub 1167, E-7 Sub 1166) (Solar Rebate Program); and second, DEC and DEP's *Petition for Approval of Community Solar Program* in Docket Nos.E-2, Sub 1169 and E-7, Sub 1168 (Community Solar Program).

Under the proposed Solar Rebate Program, any customer applying for the rebate must be on Rider NM or NM-4B. In addition, if the customer is receiving service under a NMNTD rate schedule, RECs would be retained by the utility. This waiver request would therefore be applicable to the RECs generated by customers participating in the Solar Rebate Program under a NMNTD rate schedule.

Under the proposed Community Solar Program, the Companies propose retiring RECs produced by community solar facilities on behalf of the participating customers. Therefore, the waiver requests in this order do not apply to the Community Solar program.

The Public Staff presented this matter to the Commission at its Regular Staff Conference on June 4, 2018. The Public Staff recommended that DEC's and DEP's request for waivers of certain provisions of Commission Rules R8-66 and R8-67 with regard to the registration and reporting requirements for installation of new rooftop-mounted solar PV electric generating systems be granted, as such waivers would reduce the burden of the reporting and compliance requirements pertaining to the generation and transfer of RECs between NMNTD customers and the utilities.

The Public Staff also noted that HB 589 established new G.S. 62-126.4, which directs each electric public utility to file for Commission approval revised net metering rates for electric customers that (i) own a renewable energy facility for that person's own primary use or (ii) are customer generator lessees, which are to be established "only after an investigation of the costs and benefits of customer-sited generation." As part of that revision of net metering rates, the allocation of RECs from net metered, customer-sited generation may be reconsidered and may impact the application of this waiver. The Public Staff further noted, however, that G.S. 62-126.4(c) provides:

> [U]ntil the rates have been approved by the Commission as required by this section, the rate shall be the applicable net metering rate in place at the time the facility interconnects. Retail customers that own and install an on-site renewable energy facility and interconnect to the grid prior to the date the Commission approves new metering rates may elect to continue net metering under the net metering rate in effect at the time of interconnection until January 1, 2027.

As such, this waiver may require modification upon the revision of the net metering rates offered by DEC and DEP.

No other party filed comments in this proceeding.

Based on the foregoing, the Commission is of the opinion that the requested waiver from portions of Commission Rules R8-66 and R8-67 should be granted, but that DEC and DEP should be required to provide NC-RETS with facility information necessary to maintain transparency as discussed above. The Commission will allow DEC and DEP to report into NC-RETS the estimated amount of energy produced by the participants' solar facilities. DEC and DEP shall maintain and make available for review by the Public Staff and the Commission supporting documentation to validate participation levels and its estimate of electricity produced. DEC and DEP shall include in their REPS compliance filings a summary of the results of site visits. In addition, DEC and DEP shall on a monthly basis provide NC-RETS with a list of participating customers, including facility location and size. NC-RETS shall post this information on its website in a manner that will facilitate its use by other registries seeking to preclude the double issuance of RECs.

The Commission agrees with the Public Staff that the revision of net metering rates pursuant to G.S. 62-126.4 may result in changes to the allocation of RECs from net-metered, customer-sited generation and impact the applicability of this waiver to some net-metered customers. Until those revised rates are before the Commission, however, it is appropriate for this waiver to be implemented to allow DEC and DEP to more efficiently utilize those RECs that are currently being allocated to them by their net-metered customers.

IT IS, THEREFORE, ORDERED as follows:

1. That participants in DEC Rider NM or DEP Rider NM-4B under a NMNTD schedule are exempt from the following requirements of Commission Rule R8-66:

(a) Filing a registration statement, and annual updates, pursuant to Rule R8-66(b);
(b) Annually filing certifications of compliance with all federal and state laws, regulations, and rules for the protection of the environment and conservation of natural resources, and annually filing certification that the facility is operated as a renewable energy facility pursuant to Rule R8-66(b)(4) and (5);
(c) Annually filing a compliance statement to certify that any RECs sold to an electric power supplier will not be remarketed or resold for any purpose and annually reporting whether it sold any RECs during the prior year pursuant to Rule R8-66(b)(6); and
(d) Annually consenting to audits and verify registration statement, pursuant to Rule R8-66(b)(7).

2. That DEP and DEC be granted a waiver from the 10kW threshold established in R8-67(g)(2) and (h)(8), and instead be permitted to estimate the electric power generated by a residential inverter-based solar PV system on a NMNTD rate schedule with a nameplate capacity of 20 kW or less using generally accepted analytical tools;

3. That DEP and DEC be permitted to estimate the electric power generated by a non-residential inverter-based solar PV system on a NMNTD rate schedule with a nameplate capacity of 1,000 kW or less using generally accepted analytical tools;

4. That DEC and DEP, as administrator of Rider NM and NM-4B, may forego metering each generator individually and may use the PVWatts™ Solar Calculator developed by the National Renewable Energy Laboratory for estimating the generation from participants' solar facilities, as permitted in Commission Rule R8-67(g)(2);

5. That DEC and DEP shall report the total amount of electricity produced by facilities under the Rider directly into NC-RETS in a separately identified generation project;

6. That DEC and DEP shall maintain all supporting documentation to validate participation levels for NMNTD customers, and shall provide it to the Commission and the Public Staff for review upon request;

7. That for two years from the date of this order, DEC and DEP shall verify via site visits to a statistically significant number of participating residences that the solar installations covered by this Rider continue to be operating. DEC and DEP shall include the findings of its site visits in its annual REPS compliance filing and use the findings to adjust the estimates of the electricity output of all of the Rider installations on a prospective basis. When DEC and DEP reports the results of the year-two site visits in its REPS compliance filing, it shall include a recommendation as to whether such site visits should continue; and

8. That DEC and DEP shall provide NC-RETS on a monthly basis with a list of participating customers, including the location and the kW capacity of their installations, to be made available on the NC-RETS website.

ISSUED BY ORDER OF THE COMMISSION.
This the 5th day of June, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

Commissioner Daniel G. Clodfelter did not participate in this decision.

DOCKET NO. E-2, SUB 1159
DOCKET NO. E-7, SUB 1156

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Joint Petition of Duke Energy Carolinas, LLC,	)	ORDER MODIFYING
and Duke Energy Progress, LLC, for	)	AND APPROVING
Approval of Competitive Procurement of	)	JOINT CPRE PROGRAM
Renewable Energy Program	)	

BY THE COMMISSION: On July 27, 2017, the Governor signed into law House Bill 589 (S.L. 2017-192). Part II of S.L. 2017-192, enacted as G.S. 62-110.8, requires Duke Energy Carolinas, LLC (DEC), and Duke Energy Progress, LLC (DEP) (together, Duke), to file for Commission approval, on or before November 27, 2017, a program for the competitive procurement of energy and capacity from renewable energy facilities with the purpose of adding renewable energy to the State's generation portfolio in a manner that allows the State's electric public utilities to continue to reliably and cost-effectively serve customers' future energy needs (CPRE Program). In addition, Section 2(c) of S.L. 2017-192 directs the Commission to issue an order to approve, modify, or deny the program no later than February 26, 2017.

Subsection G.S. 62-110.8(b) provides that DEC and DEP may jointly or individually implement the requirements of the CPRE Program. Subsection G.S. 62-110.8(h) requires the Commission to adopt rules to implement the requirements of the CPRE Program, including specifically addressing the following:

(1) Oversight of the competitive procurement program.

(2) To provide for a waiver of regulatory conditions or code of conduct requirements that would unreasonably restrict a public utility or its affiliates from participating in the competitive procurement process, unless the Commission finds that such a waiver would not hold the public utility's customers harmless.

(3) Establishment of a procedure for expedited review and approval of certificates of public convenience and necessity (CPCN), or the transfer thereof, for renewable energy facilities owned by the public utility and procured pursuant to this section. The Commission shall issue an order not later than 30 days after a petition for a certificate is filed by the public utility.

(4) Establishment of a methodology to allow an electric public utility to recover its costs pursuant to G.S. 62-110.8(g).

(5) Establishment of a procedure for the Commission to modify or delay implementation of the provisions of this section in whole or in part if the Commission determines that it is in the public interest to do so.

On November 6, 2017, in Docket No. E-100, Sub 150, after receiving comments and proposed rules from Duke, the Public Staff, and other interested parties, the Commission issued an Order (CPRE Rule Order) adopting Commission Rule R8-71 (CPRE Rule). Commission Rule R8-71(c) requires Duke to seek Commission approval of guidelines for the implementation of its CPRE Program and Commission Rule R8-71(g) requires Duke to file an initial CPRE Program plan. Commission Rule R8-71(c)(v) provides that Duke's CPRE Program guidelines shall include a copy of the pro forma contract(s) to be utilized in the CPRE Program. Commission Rule R8-71(c)(2) provides that Duke shall identify any regulatory conditions and/or code of conduct provisions that it seeks to waive for the duration of the CPRE Program Procurement Period.

On November 27, 2017, Duke filed a petition for approval of its proposed joint CPRE Program, seeking Commission approval of the program on behalf of DEC and DEP. Included with Duke's filing is its proposed initial CPRE Program guidelines, pro forma power purchase agreements (PPAs), initial CPRE Program plan, and requests for waivers of regulatory conditions and code of conduct requirements.

On December 1, 2017, the Commission issued an Order requiring the Public Staff to file a report with the Commission addressing whether Duke's proposed CPRE Program is reasonably designed to meet the requirements of G.S. 62-110.8 and Commission Rule R8-71. In addition, the Commission directed the Public Staff to include in its report a recommendation as to whether the Commission should approve Duke's proposed CPRE Program, accept the initial CPRE Program plan, grant Duke's requested waivers of regulatory conditions and code of conduct requirements, or take any other action in response to Duke's petition and related filings. That Order also allowed for intervention by interested persons and set a schedule for the filing of comments and reply comments.

The following filed petitions to intervene, which were granted by orders subsequently issued in this docket: the North Carolina Sustainable Energy Association (NCSEA), the North Carolina Clean Energy Business Alliance (NCCEBA), and Duke Energy Renewables, Inc. (Duke Renewables). Duke Renewables' petition to intervene was accompanied by its comments.

On or after January 2, 2018, the Commission received approximately 450 consumer statements of position, requesting that the Commission require solar electric generating facilities that are participating in the CPRE Program to be landscaped with native plants that serve as a habitat for pollinators.

On January 10, 2018, the Public Staff filed its report and initial comments.

On January 11, 2018, NCCEBA and NCSEA jointly filed comments.

On January 26, 2018, Duke, Duke Renewables, and the Public Staff filed reply comments.

Duke's Petition for Approval of CPRE Program and Associated Filings

In its petition, Duke argues that its proposed CPRE Program serves the public interest and will meet the objectives S.L. 2017-192. Duke's petition provides a detailed overview of its proposed CPRE Program, intended to identify how Duke will comply with the requirements of G.S. 62-110.8. First, Duke states that it will jointly issue CPRE RFP Solicitations, as allowed by G.S. 62-110.8(b), but DEC and DEP will otherwise maintain independent CPRE Program planning, reporting, and cost recovery. Second, Duke proposes allocating the total 2,660 MW required to be procured under the CPRE Program over the 45-month CPRE Program Procurement Period by conducting four CPRE RFP Solicitations (which Duke refers to as "Tranches"), with the first proposed to begin in May 2018 and the last to end in August 2021. Duke states that the schedule for future CPRE RFP Solicitations will be refined as Duke gains experience during the initial CPRE RFP Solicitation. Third, Duke states that it considered the statutory criteria in G.S. 62-110.8(c) in developing a proposed allocation of procured generating capacity between DEC and DEP for each of the four CPRE RFP Solicitations. Similar to its proposed schedule, Duke states the allocation between DEC and DEP may evolve in future CPRE Program plans based on the experience gained during the implementation of the CPRE Program. Fourth, to meet the cost-effectiveness requirements of G.S. 62-110.8(b)(2), and consistent with the requirements of Commission Rule R8-71(f)(2), Duke states that it plans to calculate and publish 20-year avoided cost rates for DEC and DEP using the peaker methodology at least 60 days prior to the planned issuance date of the first CPRE RFP Solicitation. Fifth, Duke outlines several provisions included in the pro forma PPA, noting specifically the inclusion of "control instructions" and emergency condition and force majeure system operator instructions.[1] Sixth, with respect to the 30% limit on utility-owned facilities provided in G.S. 62-110.8(b)(4), Duke seeks to clarify three issues for the Commission: 1) Duke states that it has voluntarily agreed to recognize both "self-developed proposals" and PPA proposals offered by any Affiliate as being subject to the 30% limit; 2) Duke states that it plans to apply the 30% limit to the total 2,660 MW over the CPRE Program Procurement Period, rather than applying the 30% limit to each CPRE RFP Solicitation; and 3) Duke states that it will not apply the 30% limit to "asset acquisition proposals." As proposed by

[1] The control instructions would allow Duke to dispatch, operate, and control renewable energy facilities under the CPRE Program in the same manner as it does DEC and DEP's own generating resources, as allowed by G.S. 62-110.8(b). These provisions would require payment for foregone output from a renewable energy facility only if the facility output is curtailed by more than 5% of the facility's expected annual output, if interconnected to DEC's system, and 10% of the facility's expected annual output, if interconnected to DEP's system. Duke also describes the system operator instructions, which would allow "full curtailment" during emergency conditions or force majeure conditions without compensation.

Duke, asset acquisition proposals include three proposal cost structures: renewable resource asset transfer plus EPC,[1] build own transfer, and renewable resource asset.

Duke then identifies how DEC and DEP plan to address generator interconnection-related issues under the CPRE Program. Duke first notes that its proposed CPRE Program guidelines would require a market participant to have submitted an interconnection request under the North Carolina Interconnection Procedures (NCIP) or the South Carolina Generator Interconnection Procedures (SC GIP) and received a queue number at the time of proposal submission. Duke then recognizes that existing interconnection customers seeking to interconnect to Duke's transmission systems may desire to offer their planned facility into the CPRE Program. To accommodate this possibility, Duke proposes allowing these interconnection customers to submit new NCIP or SC GIP interconnection requests, while retaining their queue number and position under the initial request. Duke then states that it has identified the need to rely on more efficient and coordinated "grouping studies" to evaluate potential system upgrade costs as part of step one of the proposal evaluation process. This proposed grouping study concept is included at Section 4.3 of Duke's proposed CPRE Program guidelines, and Duke states that it will propose any necessary revisions to the NCIP through the review process underway in Docket No. E-100, Sub 101. Duke next addresses its proposal that system upgrade costs on the utility-side of the point of interconnection be recovered through base rates. Duke states that while the cost of interconnection facilities between the generating facilities and the point of interconnection can be reasonably projected based upon the size of the generating facility and the voltage of the line to which the generator seeks to interconnect, the upgrade costs on the utility's side of the point of interconnection can vary dramatically depending on the grid's capability to integrate additional generation at the requested point of interconnection. To reduce the risk of unknown costs to the renewable energy facilities proposed in a CPRE RFP Solicitation, Duke proposes an evaluation methodology that segregates the "upgrade costs" from the "proposal costs." Under Duke's proposal, market participants will develop proposals that include only the generating facility and interconnection facilities costs, and DEC and DEP will seek recovery of upgrade costs through future general rate case proceedings. Under this proposal, Duke argues that its customers should benefit from lower proposal costs, or, at a minimum, be indifferent between higher CPRE proposal costs or recovery through base rates.

In conclusion, Duke argues that it has developed its proposed CPRE Program to meet the filing requirements of Commission Rule R8-71 and to achieve the mandates and objectives of G.S. 62-110.8. Therefore, Duke requests that the Commission issue an order 1) approving its proposed CPRE Program, including the CPRE Program guidelines, pro forma CPRE PPA, and related documents, as reasonable and appropriate for implementing the initial CPRE RFP Solicitation, 2) accepting the initial CPRE Program plan as reasonable for planning purposes, 3) granting the requested waivers of regulatory conditions and code of conduct requirements, and 4) granting such other and further relief as the Commission deems just and reasonable and in furtherance of the public interest.

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[1] "EPC" refers to the "Engineering, Procurement, and Construction agreement offered by the third-party developer for execution by DEC and DEP," which, for this proposal cost structure, would be submitted in the CRPE RFP along with the proposal for the facility.

Comments of NCCEBA and NCSEA

Through their joint comments, NCCEBA and NCSEA first respond to Duke's petition for approval of the CPRE Program. NCCEBA and NCSEA next argue that the Commission should require Duke to make several changes to its proposed pro forma PPA. NCCEBA and NCSEA contend that the fact that Duke based its pro forma PPA on bilateral PPAs that Duke has previously negotiated with solar developers should not create a presumption of commercial reasonableness. Instead, NCCEBA and NCSEA state that Commission approval of the pro forma PPAs is required by statute and that the Commission should take this opportunity to ensure that the terms of the pro forma PPA are commercially reasonable. NCCEBA and NCSEA then agree with Duke's proposed approach to recovery of network upgrade costs, wherein CPRE market participants develop proposals that include only the generating facility and interconnection facilities costs, and Duke separately seeks to recover network upgrade costs in a future general rate case proceeding.

NCCEBA and NCSEA then respond to Duke's proposed CPRE Program guidelines stating that the primary purposes of the CPRE Program guidelines are to meet the requirements of G.S. 62-110.8 and Commission Rule R8-71. NCCEBA and NCSEA express concerns that the following specific sections of Duke's proposed CPRE Program guidelines do not meet those requirements:

- Section 1.3, planned CPRE allocation between DEC and DEP service territories: NCCEBA and NCSEA argue that Duke should not be allowed to introduce locational allocation designations within DEC and DEP's respective service territories because they failed to provide that information in the proposed CPRE Program guidelines. NCCEBA and NCSEA support their argument by citing to Commission Rule R8-71(g) and by arguing that ample notice and more granular locational data are necessary for transparency, proper planning by market participants, and elimination of any unfair advantage for Duke and its Affiliates. Therefore, NCCEBA and NCSEA further argue that Duke should be required to provide applicable locational guidance for Tranches 2 and 3 now, and for Tranche 4 in its 2018 CPRE Program plan, which is due to be filed on or before September 1, 2018.

- Section 2, CPRE Program RFP Solicitation timetable: NCCEBA and NCSEA argue that the contracting period for PPAs included in Duke's proposed CRPE RFP Solicitation schedule, is unnecessarily long and should be reduced from 90 to 30 days, given that the pro forma PPAs are reviewed and approved by the Commission. Further, NCCEBA and NCSEA argue that the date for the issuance of the Trache 4 RFP Solicitation should be accelerated to July 2020 from November 2020, so that market participants can reduce their proposal costs by taking advantage of the federal Solar Investment Tax Credit (ITC), which requires facility construction to begin before December 31, 2020.

- Section 3.2, market participant requirements:

    - Requirement No. 2: NCCEBA and NCSEA argue that Duke should not be allowed to change the generation capacity eligibility requirement from the range of 1.0-MW to 80-MW, as proposed for Tranche 1. They argue that a change in this requirement that is applied to Tranches 2, 3, and 4 would disadvantage market participants that submitted interconnection requests prior to the change in eligibility, resulting in the withdrawal of the project from the interconnection queue. NCCEBA and NCSEA further argue that requirement No. 2 is inconsistent with G.S. 62-110.8(a).

o Requirement No. 9(b): NCCEBA and NCSEA argue that Duke's proposed requirement No. 9(b) is inconsistent with Commission Rule R8-71(l)(4) in that the proposed requirement would require both utility and non-utility market participants to provide the Independent Administrator with revenue assumptions after the initial term. They argue that Rule R8-71(l)(4) only requires this assumption to be provided as related to utility-owned proposals.

o Requirement No. 10: NCCEBA and NCSEA argue that a proposal sponsor should be required to show "experience developing facilities of the same renewable energy type (rather than technology)."

o Deficient Proposals: NCCEBA and NCSEA argue that section 3.2 should include a "cure" period of five days in the event that the Independent Administrator finds a proposal to be deficient.

o Waiver: NCCEBA and NCSEA argue that the provision in section 3.2 requiring proposal sponsors to waive recourse against Duke and the Independent Administrator for certain acts taken in the execution of the CPRE Program should be deleted. In support of their argument, NCCEBA and NCSEA state that the Commission's rules do not eliminate the ability to seek remedy before the Commission for improper rejection of a bid or refusing to execute an agreement with a bidder selected by the Independent Administrator.

- Section 3.3, Proposal Types: NCCEBA and NCSEA argue that the Renewable Resource Asset Transfer, an asset acquisition proposal type, should be eliminated because partially developed facilities cannot be fairly priced and compared to other types of proposals. Further, they argue that it is impossible for a partially developed asset to be bid into a competitive solicitation because the developer does not have an "all-in price for the output of its project." NCCEBA and NCSEA further state that it appears that Duke is attempting to exclude these types of projects from the statutory 30% cap on utility self-developed projects, which they argue is not permitted under G.S. 62-110.8 or Commission Rule R8-71.

- Section 3.5.1, Avoided Cost Rate: NCCEBA and NCSEA state that they agree with Duke's approach to include DEC and DEP's respective 20-year avoided cost rates using the peaker methodology, and, for the Tranche 1 RFP Solicitation, to apply the peaker methodology to develop a generic large qualifying facility (QF) avoided cost profile. However, NCCEBA and NCSEA request additional details on "exactly how this will work in connection with the pricing and scoring of bids and how bids will be translated into rate structure."

- Section 3.5.2, Pro forma CPRE PPA: NCCEBA and NCSEA state that this section of the guidelines is confusing with respect to what Duke is proposing on the timing and approval of the initial pro forma PPA for use in the Tranche 1 CPRE RFP Solicitation. They further state that waiting until 30 days prior to the Tranche 1 CPRE RFP Solicitation to finalize the pro forma PPA does not give market participants sufficient notice of the terms and conditions on which their proposals must be based or sufficient opportunity to object to unreasonable terms and conditions.

In addition, they argue that there is no reason to delay review and finalization of the pro forma PPA for the Tranche 1 RFP Solicitation, and that Duke should be required to obtain Commission approval prior to making changes to the pro forma PPA in future tranches. Finally, NCCEBA and NCSEA state that Duke did not include MIPAs or EPC contracts in the guidelines or program plan, which NCCEBA and NCSEA believe also require Commission approval. In addition to these comments, NCCEBA and NCSEA included a redline markup of Duke's proposed pro forma PPA as a part of its reply comments.

- Section 4.4, Grid Upgrade Evaluation: NCCEBA and NCSEA state that they support Duke's proposal to conduct an expedited evaluation of the grid upgrade costs associated with all CPRE proposals. Further, they state that they have been "working cooperatively" with Duke to determine whether changes to the current interconnection procedures would better facilitate the CPRE Program and improve the interconnection process, and that they are awaiting receipt of Duke's most recent proposal on this subject. NCCEBA and NCSEA further state that they intend to supplement this filing with comments addressing potential changes to the interconnection procedures that could affect the CPRE Program.

- Section 7, CPRE Standards of Conduct: NCCEBA and NCSEA argue that part of this section related to Duke's Evaluation Team supporting the Independent Administrator's Step 1 evaluation and ranking process and evaluating proposals in Step 2 of the evaluation process is inconsistent with Commission Rule R8-71(f)(3).

NCCEBA and NCSEA then set out a number of comments on Duke's pro forma PPA, including provisions that NCCEBA and NCSEA believe should be revised. They describe these changes as the "most significant amendments," and include additional revisions in the redline markup filed with their comments. Finally, NCCEBA and NCSEA identify the following provisions in Duke's initial CPRE Program plan that they do not believe comply with G.S. 62-110.8 and Commission Rule R8-71: Section 2.3 (Planned RFP Solicitations), Section 2.4 (Allocation of Resources), and Section 2.5 (Locational Designation). In conclusion, NCCEBA and NCSEA request that the Commission consider the issues raised in their comments and their requested revisions and amendments to Duke's initial CPRE Program guidelines, pro forma PPA, and initial CPRE Program plan.

Duke Renewables

By its comments, Duke Renewables argues that market participant Requirement No. 9(b) included in Section 3.2 of Duke's proposed initial CPRE Program guidelines goes beyond the requirements of Commission Rule R8-71(l)(4) by requiring proposal sponsors for both utility owned and non-utility owned facilities to disclose trade secret information. Duke Renewables argues that this section of the guidelines should only require an electric public utility, and not non-utilities, to make available information related to assumptions about pricing after the initial term.

By its reply comments, Duke Renewables argues that there is a need for clarification in how the 30% limitation on the utility's self-development of projects in G.S. 62-110.8(b)(4) will be applied to certain commercial situations. Duke Renewables proposes the following guidance on which projects count toward the 30% limit with respect to an Affiliate of Duke: 1) the 30% limit should not apply to any project that is not controlled, directed or indirectly, by the Affiliate, and control should be akin to the definition used in Securities and Exchange Commission Rule 405; and 2) the 30% limit should not apply to any project in which an Affiliate obtains an ownership interest after the proposal is submitted in an RFP Solicitation. Finally, Duke Renewables argues that none of the regulatory conditions or code of conduct requirements waived with respect to the CPRE Program would apply as between a market participant and an Affiliate.

The Public Staff's Report and Comments

In the Public Staff's report and comments, the Public Staff states that it reviewed Duke's CPRE Program filing and agrees with Duke that the filing generally adheres to the requirements of Commission Rule R8-71. The Public Staff further states that it does not take issue with any of the proposals included in Duke's proposed CPRE Program guidelines. The Public Staff specifically noted Duke's planned allocation of capacity to be procured through the RFP Solicitation between DEC and DEP in Tranche 1, and agreed with Duke that the designated allocation may need to evolve over time to ensure that the CPRE Program requirements are being met in a manner that ensures continued reliable electric service to customers while procuring the most cost-effective renewable energy resource capacity available.

The Public Staff also addressed the pro forma PPA to be utilized in the Tranche 1 CPRE RFP Solicitation. The Public Staff states that it reviewed the pro forma PPA and compared the terms and conditions to the current negotiated PPA forms generally utilized by Duke in its negotiations with QFs that are not eligible for the Commission-approved standard contract. The Public Staff states that it does not take exception to the provisions in the pro forma PPA, but notes two key differences between the pro forma PPA and the "non-CPRE contracts" used by the utilities: 1) the pro forma PPA includes provisions related to the transfer of renewable energy and environmental attributes to the utility; and 2) the pro forma PPA includes the provisions designed to effectuate the requirements that renewable facilities participating in the CPRE Program commit to allow the procuring public utility rights to dispatch, operate, and control the solicited renewable energy facility in the same manner as the utility's own generating resources. These differences, the Public Staff states, are based on the requirements in G.S. 62-110.8(b). The Public Staff concludes that the first provisions are comparable to contract provisions currently used in securing renewable energy certificate (RECs) for compliance with the Renewable Energy and Energy Efficiency Portfolio Standard (REPS). Therefore, the Public Staff agrees that inclusion of these provisions is appropriate. With regard to the second provision, the Public Staff notes that this would allow curtailment of the electric generation from a renewable energy facility without compensation until output is curtailed by 5% of the facility's expected annual output if interconnected to DEC's electric system, and by 10% of the facility's expected annual output if interconnected to DEP's electric system. In addition to this curtailment provision, the Public Staff further notes that the pro forma PPA includes provisions allowing curtailment during emergency conditions or force majeure conditions without compensation. The Public Staff states that it does not take issue with these provisions; however, the Public Staff notes that these provisions further heighten the need for Duke to have and implement non-discriminatory and transparent curtailment procedures resulting from control instructions and system operator instructions.[1]

[1] On January 30, 2017, Duke filed these procedures in Docket No. E-100, Sub 148.

The Public Staff next addresses Duke's requested waivers of regulatory conditions and code of conduct requirements. The Public Staff notes that Duke requested that the Commission waive the following regulatory conditions and code of conduct requirements for the duration of the CPRE Program: 1) Regulatory Condition No. 3.4, restricting the purchase and sale of electricity between DEC, DEP, and their Affiliates; 2) Regulatory Conditions No. 5.2 and Section III, D. 3(a) and (b) of the Code of Conduct, related to the provision or transfer of goods and services, transfer pricing, and cost allocation with respect to DEC, DEP, and their Affiliates; 3) Section III, D. 8 of the Code of Conduct, related to the transfer of non-public information under G.S. 62-110.8(e); 4) Regulatory Condition Nos. 3.1(a), 3.1(b), and 3.1(c), pertaining to Affiliate contracts. The Public Staff states that it reviewed these proposed waivers and believes that they are reasonable and appropriate for the purposes of implementing the CPRE Program.

The Public Staff then addresses the following issues:

- Grid locational guidance: The Public Staff cites Section 3.5.3 of Duke's proposed Program guidelines, in which Duke identified the Tranche 1 allocation between DEC and DEP, and notes that Duke did not designate specific locations or zones where projects must be sited in order for market participants to bid proposals into the Tranche 1 Solicitation. The Public Staff further notes that Duke indicated its intention to release documentation in the pre-solicitation information that will provide guidance to market participants on areas that have known transmission and distribution limitations, which might be in the form of a map and/or table that shows circuits and/or substations that have "no availability." The Public Staff states that it agrees with Duke that the goal of the CPRE Program is to steer market participants to the most cost-effective interconnection locations, and that it supports Duke's proposal to provide grid locational guidance and estimated cost information. The Public Staff recommends that this information be as detailed as possible to help guide prospective bidders in identifying the most cost-effective locations to seek to interconnect. Finally, the Public Staff observes that non-public information may be used in developing grid locational guidance and that, to the extent that this information is made available to the Duke Proposal Team prior to the issuance of a Solicitation, the information should be provided to other market participants pursuant to G.S. 62-110.8(e) and Commission Rule R8-71(e)(5).

- Grouping Studies: The Public Staff cites Section 4.3 of Duke's proposed Program guidelines, and summarizes Duke's proposed "grouping study" approach to evaluating grid upgrade costs. This process would involve the Independent Administrator conducting an initial evaluation of quantitative and qualitative factors for each project, ranking these projects, and sending "groupings" to Duke's Study Team to determine the grid upgrade[1] values in $/MWh, which can be incorporated into the proposal price for final ranking of proposals. Further, the Public Staff notes that Duke indicates that treatment of existing queue positions, including cost responsibility for grid upgrades, will continue to follow the NCIP and the SC GIP in effect at the time of the RFP release and that grid upgrade costs will be used in the evaluation process to ensure least cost overall projects are selected and remain below avoided cost. In addition, the Public Staff notes Duke's proposed approach attempts to address a challenge in the timing of proposal submission in that Duke anticipates proposals submitted in a CPRE RFP Solicitation would

[1] As used by Duke the term "grid upgrades" refers to transmission network upgrades and distribution upgrades, but does not include interconnection facilities.

precede the System Impact Study and Facilities Study steps in the interconnection procedures. Because interconnection facility costs are reasonably predictable, but grid upgrade costs can vary dramatically, market participants would lack significant information on which to base their proposals. The Public Staff does not object to Duke's proposed grouping study approach, and agrees with Duke that this approach will reduce uncertainty for market participants. Further, the Public Staff states that as long as the Independent Administrator includes in its evaluation the grid upgrade costs associated with the project, only the lowest cost proposals that are below avoided cost should be selected.

- Cost Recovery of Grid Upgrades: The Public Staff notes that Duke's proposed CPRE Program guidelines propose calculate grid upgrade costs as part of its valuation of projects, but proposes recovering the grid upgrade costs through future adjustments to general cost of service, rather than assigning these costs to a specific CPRE proposal. The Public Staff states that this deviates from the Public Staff's original understanding of how the program would be implemented, and, to an extent, from the Public Staff's past recommendations, which the Commission accepted, regarding the direct assignment of interconnection costs to the interconnection customer. The Public Staff cites the 2016 proceedings on DEC and DEP's applications for cost recovery pursuant to G.S. 62-133.8(h) as examples. The Public Staff's fundamental concern with this approach is that it makes it more difficult to monitor compliance with the 1% cap on costs recovered through the CPRE Program rider established in G.S. 62 110.8(g). However, the Public Staff acknowledges that practical challenges in assigning these costs to a specific project would be time consuming and result in delays in proposal evaluation and selection, potentially impacting Duke's ability to comply with the CPRE procurement requirement within the 45-month initial period. The Public Staff further acknowledges that Duke's proposal may allow for a more expedited review, could expose market participants to less risk associated with grid upgrade costs, and, in any event, these costs would be subject to audit and prudency review in a general rate case. In summary, the Public Staff states that it prefers the traditional approach of assigning all interconnection costs to the interconnection customer; however, in light of these challenges, the Public Staff does not object to Duke's proposed cost recovery of grid upgrade costs. The Public Staff recommends requiring Duke to file reports detailing these costs as a part of the annual CPRE compliance report.

- Asset Acquisition Proposals: The Public Staff then addresses Duke's proposal to recognize not only utility self-developed proposals, but also third-party PPA proposals offered by any Duke Affiliate as counting toward the 30% limitation in G.S. 62-110.8(b)(4). The Public Staff notes that Duke proposes that Asset Acquisition proposals be sent to Duke for review to ensure that the proposals meet Duke's design requirements, and the Public Staff does not disagree with this process. However, the Public Staff recommends that the Commission require Duke to make its design requirements available to the Independent Administrator and market participants as early as possible to ensure that this information can be incorporated into proposal development. In addition, the Public Staff emphasizes the importance of ensuring that information is "masked" to ensure fairness in the review by Duke's Proposal Team.

- Curtailment Assumptions for utility self-developed and asset acquisition proposals: The Public Staff notes the importance that projects proposed as an asset acquisition or a utility self-developed proposal include curtailment estimates used in the evaluation of these projects that are comparable to those included in third-party PPA proposals. Because these projects could be subject to different dispatch characteristics than those owned by third parties, and the actual output of these facilities could be lower than those used in evaluating the projects, there is a risk that these projects would be less cost-effective for customers than other options selected in the CRPE RFP Solicitation.

In conclusion, the Public Staff states that it believes that Duke's CPRE Program filing complies with the requirements of Commission Rule R8-71, and recommends that the Commission approve Duke's proposed CPRE Program, accept the initial CPRE Program plan, and grant Duke's requested waivers of regulatory conditions and code of conduct requirements, subject to the additional considerations raised by the Public Staff.

By its reply comments, the Public Staff responds to NCCEBA and NCSEA's comments related to provisions in the pro forma PPA. In light of those comments, the Public Staff recognizes that some of these provisions may create challenges for market participants seeking to obtain financing for projects, and states that it is appropriate to further review these provisions to ensure that all the terms in the pro forma PPA are commercially reasonable. Specifically, the Public Staff agrees with NCCEBA and NCSEA's suggestions to 1) add a provision to the pro forma PPA that provides an opportunity to cure non-material breaches, 2) require that detailed grid locational information be provided to market participants as early as possible, 3) reduce the contracting period for PPA agreements from 90 to 30 days, 4) remove the limited recourse provision from section 3.2 of Duke's proposed CPRE Program guidelines, and 5) require Duke to provide additional information regarding how scoring of bids will be translated into a rate structure.

Duke's Reply Comments

By its reply comments, Duke recites a number of upcoming deadlines in the CPRE Program and future opportunities for market participant input prescribed by Commission Rule R8-71. Duke then states that it has attempted to address all issues raised by the Public Staff, as well as any "legal or significant policy issues" raised by the other parties that implicate statutory or regulatory requirements under Rule R8-71. However, Duke states that it is not responding to each recommendation made by NCCEBA and NCSEA and that given the "tight time frame" for developing the CPRE Program, it plans to consider these comments and recommendations through the pre-solicitation process. Based upon the Public Staff's report and comments and Duke's responses thereto, Duke submits that its filings meet the statutory requirements and those of Commission Rule R8-71. Duke, therefore, renews its request for approval of these filings and its requested waivers of the regulatory conditions and code of conduct provisions.

In response to the Public Staff's report and comments, Duke notes that the Public Staff found that Duke's proposed CPRE Program generally meets the requirements of Commission Rule R8-71. In addressing the Public Staff's suggestion that the curtailment procedures being developed at the Commission's direction include curtailment of facilities participating in the CPRE Program, Duke agrees to include the CPRE Program PPA assets that are curtailed for emergency conditions in its required quarterly report. However, Duke draws a distinction between "emergency condition curtailments" and the discretionary rights to control CPRE Program assets. Duke states that control actions taken over CPRE facilities are likely to be "more routinely issued (as needed for operational reasons)" up to the respective limits for DEC (5% of expected annual output) and DEP (10% of expected annual output), as those limits are proposed in Duke's CPRE Program PPAs. In response to the Public Staff's suggestion that curtailment estimates used in the evaluation of asset acquisition or utility self-developed proposals be comparable to those included in third-party PPA proposals, Duke states that it does not anticipate that this will be a material issue because Duke plans to dispatch or curtail all of these assets in a comparable manner.

In addressing the Public Staff's comments on the value of Duke providing "grid locational guidance" as early as possible, Duke states that it plans to develop and deliver initial grid locational guidance to the Independent Administrator in March 2018 as part of the Tranche 1 pre-solicitation information, and will refine this information for future Tranches. Duke also agrees that grid locational guidance should not and will not be made available to any Duke Proposal Team members prior to the issuance of the RFP documents as part of the pre-solicitation information sharing process.

In response to the Public Staff's recommendation that the Commission require Duke to make its design requirements for asset acquisition bids available to the Independent Administrator and prospective bidders as early in the process as possible, Duke cites Section 3.5.5 of the proposed guidelines. Duke states that in Section 3.5.5, it has committed to have its Proposal Team develop and deliver initial asset acquisition proposal design specifications to the Independent Administrator in March 2018 as part of the Tranche 1 pre-solicitation information. Further, Duke states that the Public Staff's recommendation to "mask" identifying information in asset acquisition bids would result in concealing information necessary to conduct due diligence and confirm that design specifications have been met. In addition, Duke states that "no competitive concerns" should arise in the Proposal Team's asset acquisition evaluation because this work occurs prior to the Independent Administrator's evaluation in step one and because the Evaluation Team and the Proposal Team are to be segregated from each other and are prohibited from communicating regarding any aspect of the RFP for its duration. In short, Duke believes that the Independent Administrator's role and the structure of the RFP effectively ensure that all bids will be treated equitably.

Finally, Duke addresses the Public Staff's comments that, while it does not object to Duke's plan to use grouping studies for interconnection study evaluation or proposed cost recovery, this proposal deviates from the Commission's traditional approach, and the approach that the Public Staff has recommended in other proceedings. Duke suggests that, in approving its proposed grouping study and cost recovery approaches, the Commission should explicitly state that such approval is based upon the unique "practical challenges" and circumstances of the CPRE Program, and that this approval is not precedential. In addition, Duke agrees to file information in DEC and DEP's annual CPRE compliance report identifying the grid upgrades resulting from each CPRE solicitation, along with the associated costs.

In addressing the other parties' comments, Duke first states that it has attempted to address the comments of NCCEBA and NCSEA that raise legal or policy questions under G.S. 62-110.8 and Commission Rule R8-71, and those comments that are "more preferential in nature" will be addressed during the Tranche 1 pre-solicitation process. Specifically, Duke addresses the following aspects of its proposed CPRE Program in response to these comments:

- Market participant eligibility: In response to NCCEBA and NCSEA's argument that Duke should not be allowed to change the maximum eligibility of 80 MW and the minimum eligibility of 1 MW, Duke states that it is not proposing and does not intend to reduce the maximum eligibility size, but may elect to increase the minimum size above 1 MW if the Tranche 1 experience suggests that those projects are not likely to be successful in the CPRE bidding process. Duke views a potential increase in minimum generation capacity as "fully consistent with" G.S. 62-110.8(a), and notice of such a change would be provided to market participants through the RFP pre-solicitation process.

- Schedule for Allocating procurement over 45 months: Duke objects to NCCEBA and NCSEA's request that the Commission require Duke to accelerate the Tranche 4 RFP to July 2020 so that market participants can qualify for the Solar ITC. First, Duke states that this change would compress the CPRE procurement to 40 months rather than the statutory 45 months. Second, Duke argues that NCCEBA and NCSEA do not provide a basis in statute or Commission rule for demonstrating that Duke's proposed schedule is unreasonable. Third, Duke notes that the CPRE Program is not limited to solar facilities so not all market participants would be relying on the availability of the Solar ITC, which, Duke observes, could be amended or extended by Congressional action. Fourth, Duke states that compressing the schedule could result in the procurement of more than the statutorily required 2,660 MW, given that G.S. 62-110.8(b)(1) allows for reduction of the total procurement if Duke executes PPAs and interconnection agreements representing more than 3,500 MW in generating capacity that is not subject to Duke's economic dispatch or curtailment. Finally, in response to NCCEBA and NCSEA's request that the Commission reduce the contracting period from 90 to 30 days, Duke states that 90 days is appropriate for the Tranche 1 RFP and could be revised in the future, that Duke will endeavor to expeditiously complete these contracts in a shorter time frame, and that the CPRE Program plan states that 90 days may be needed to finalize agreements for asset acquisition proposals.

- Evaluation of Renewable Resource Asset Transfer: Duke disagrees with NCCEBA and NCSEA's comments regarding the impossibility of evaluating the renewable resource asset transfer subcategory of asset acquisitions and their questions about how these facilities would count toward the 30% cap on utility self-developed proposals, if at all. Duke states that it plans to accept only asset acquisition proposals that are in advanced stages of development, and that this distinguishes these proposals from utility self-developed proposals in which Duke would complete the early stage development work. Duke further states that because the Tranche 1 CPRE RFP Solicitation requires that the renewable energy facility be placed into service prior to January 2, 2021, all projects proposed in Tranche 1 must be "reasonably advanced in their development." In addition, Duke states that the only difference in these types of proposals, from its perspective, is that the facility developer does not have an EPC contract at the time of the RFP, but that difference would not prevent the project from being bid into a CPRE RFP Solicitation and evaluated through the CPRE Program evaluation process. Duke cites Section 4.1 of its proposed CPRE Program guidelines for Duke's explanation of how asset acquisitions will be evaluated by Duke's Proposal Team prior to the Independent Administrator's Step 1 evaluation and ranking, and notes that the Public Staff reviewed this proposed approach and did not take issue with it. Finally, in addressing the 30% cap on utility self-developed proposals, Duke cites G.S. 62-110.8(b) and (b)(4) for support of its view that its proposed approach is consistent with these provisions and that, therefore, NCCEBA and NCSEA's arguments should be rejected.

- Pro forma PPAs: Duke responds to NCCEBA and NCSEA's concerns regarding the commercial reasonableness of the pro forma PPA included in Duke's petition as Attachment 2, and the redline version of the pro forma PPA that NCCEBA and NCSEA filed with their joint comments. In short, Duke rejects the notion that its pro forma PPA is not commercially reasonable, citing its acceptance by 15 counterparties for 28 projects, representing approximately 1,300 MW of new renewable energy capacity. Further, Duke states that all market participants, including Duke Renewables, will have the same opportunity to compete to receive the same pro forma PPA, and that this demonstrates that "no party will be unduly advantaged or disadvantaged" by Duke continuing to use the pro forma PPA. In addition, Duke cites G.S. 62-110.8(b)(3) and Commission Rule R8-71(f)(1)(ii-iii) as the appropriate process for providing notice of any material changes to the pro forma PPA, and the solicitation process itself as providing an opportunity to provide feedback on the terms of the pro forma PPA. Finally, Duke argues that commercial reasonableness should be left to the contracting parties rather than the Commission acting as "arbiter of the commercial reasonableness of each and every term" in the pro forma PPA and that NCCEBA and NCSEA have presented no compelling reasons why the pro forma PPA should deviate from PPAs used in other contexts. Nonetheless, Duke states that it will further evaluate whether specific revisions are appropriate for the Tranche 1 pro forma PPA and whether to allow for limited negotiation of PPA terms with third-party proposal sponsors during the RFP contracting period. Duke, therefore, commits to "transparently address these issues" during pre-solicitation process and to file the pro forma PPA at least 30 days prior to the RFP issuance date, as is required by G.S. 62-110.8(b)(3) and Commission Rule R8-71(f)(1)(iii).

- Curtailment Rights and Discretionary Control Instructions: Duke states that it reviewed NCCEBA and NCSEA's alternative methods of compensation when DEC and DEP call on a facility to curtail its output in the same manner that the utility system operator would issue dispatch down instructions to its own facilities. Duke disagrees with changing the percentages of discretionary controls from the 5% (for DEC) and the 10% (for DEP) proposed in Section 8.9 of the CPRE pro forma PPA, and argues that NCCEBA and NCSEA's alternative methods are unsupported and unacceptable for purposes of Tranche 1. Duke further argues that NCCEBA and NCSEA have not provided sufficient detail on how this proposal would work and, citing the Commission's October 11, 2017 Order issued in Docket No. E-100, Sub 148 (Avoided Cost Order), notes that the Commission rejected the idea of "take-or-pay" as inconsistent with the federal Public Utility Regulatory Policies Act of 1978 (PURPA).

- Sharing of Market Pricing Assumptions: In response to Duke Renewables comments that market participant Requirement 9.b is overly broad in its requirement that non-utility proposal sponsors would be required to share post-CPRE Program term pricing assumption, Duke agrees to amend guidelines Section 3.2.9.b prior to the Tranche 1 RFP such that the requirement would only apply to Duke. In response to the concerns expressed by Duke Renewables, NCCEBA, and NCSEA related to the disclosure of competitively sensitive information, Duke states that no market participant should be required to divulge the detailed post-term assumptions underlying their proposals and suggests that it might seek amendment to Rule R8-71(l)(4) to ensure that no market participant, including Duke, would be disadvantaged by this requirement. Alternatively, Duke proposes including an explanation in the updated Tranche 1 guidelines to reflect Duke's assumption that any utility self-developed or asset acquisition proposal would continue to receive market based revenues based upon a mechanism established by the Commission at the conclusion of the initial CPRE Program term. This, Duke argues, would meet the requirement of Rule R8-71(l), while ensuring reasonable protection of Duke's competitively sensitive and proprietary information.

• Grid Locational Guidance: In response to NCCEBA and NCSEA's comments questioning whether Duke complied with the requirement of Commission Rule R8-71(g)(2)(iv) to provide an explanation of locational allocation within DEC and DEP's respective balancing authority areas, Duke cites Section 2.5 of its proposed CPRE Program plan. In Section 2.5, Duke states that it has not designated specific locations or zones where projects must be sited for Tranche 1, and further describes the grid locational guidance that will be provided in the pre-solicitation information. In addition, Duke commits to evaluate this issue further and to update market participants when the next CPRE Program plan is filed in September 2018.

• Review of guidelines with Independent Administrator: In response to NCCEBA and NCSEA's comment that Section 7 of the proposed guidelines improperly involves Duke's Evaluation Team in the Independent Administrator's evaluation and ranking process in violation of Commission Rule R8-71(f)(3), Duke disagrees. However, Duke commits to review the guidelines with the Independent Administrator prior to the Tranche 1 RFP Solicitation to ensure compliance with the Step 1 and Step 2 evaluation processes established in Rule R8-71.

In conclusion, Duke requests that the Commission issue an order 1) approving its proposed CPRE Program guidelines, pro forma CPRE PPA, and related documents as reasonable and appropriate for implementing the Tranche 1 CPRE Program RFP Solicitation, 2) accepting Duke's initial CPRE Program plan as reasonable for planning purposes, and 3) granting Duke's requested waivers of regulatory conditions and code of conduct requirements.

Discussion and Conclusions

The Commission carefully reviewed Duke's November 27 filing and comments in support thereof, the Public Staff's report and comments, and the comments of all the parties in this proceeding. Based upon the foregoing and the entire record in this proceeding, the Commission agrees with the Public Staff that Duke's filing generally meets the requirements of Commission Rule R8-71, and that Duke's requested waivers of regulatory conditions and code of conduct requirements should be granted. However, Duke, the Public Staff, and the other parties have brought to the Commission's attention a number of disputed issues. The Commission will proceed to resolve these disputed issues, and, consistent with the conclusions reached herein, will require Duke to modify its initial CPRE Program guidelines and initial CPRE Program plan, and file revised versions of these documents as part of its required pre-solicitation filing. For reasons discussed below, Duke's proposed pro forma PPAs are approved as filed for use in the Tranche 1 CPRE RFP Solicitation only, and the Commission will require Duke to continue discussions with the Public Staff, NCCEBA, NCSEA, and other interested parties with the goal of reaching consensus on the provisions of the pro forma PPA for future CRPE RFP Solicitations.

The Commission identifies the following issues for decision:

Issue No. 1: Grid Locational Guidance

Commission Rule R8-71(g)(2) provides that, at a minimum, the CPRE Program plan shall, if designated by location, include an explanation of how the electric public utility has determined the location allocation within its balancing authority area. In its proposed guidelines, Duke states that for Tranche 1, it has not designated specific locations or zones where projects must be sited in order for market participants to bid proposals into the CPRE RFP Solicitation. However, Duke further states that it will release documentation in the pre-solicitation information intended to provide guidance to market participants on areas that have known transmission and distribution limitations. The goal of providing this information, as described by Duke, is to minimize the need for costly grid upgrades to integrate CPRE program renewable energy facilities and to provide information to market participants for use when planning development activities for renewable energy facility proposals.

NCCEBA and NCSEA argue that because Duke did not include any locational designation in its proposed guidelines or CPRE Program plan, Duke should not be allowed to introduce such considerations into the Tranche 1 CPRE RFP Solicitation. The Public Staff agreed with Duke on the overall goal of providing grid locational guidance and recommended that this information should be as detailed as possible to help guide prospective bidders in identifying the most cost-effective locations to interconnect to Duke's electric systems. The Public Staff further notes that Duke may rely on non-public information in developing grid locational guidance, and, if that information is provided to Duke's Proposal Team, then it should be provided to other market participants.

In its reply, Duke agreed that grid locational information should not be provided to Duke's Proposal Team prior to the pre-solicitation information sharing process. Duke further reiterated its commitment, as stated in Section 3.5.3 of the guidelines and Section 2.5 of the Program plan, to provide this information as part of the pre-solicitation documentation for Tranche 1, which will be transmitted to the Independent Administrator in March 2018.[1] Duke states that this information may be in the form of a map and/or table of circuits and/or substations that have "no availability" for the interconnection of additional renewable energy facilities. Finally, Duke states that it is committed to evaluate this issue further and to update market participants when the next CPRE Program plan is filed in September 2018.

The Commission concludes that Duke's failure to include the explanation contemplated by Commission Rule R8-71(g)(2)(iv) does not justify modifying or denying approval of Duke's proposed guidelines or Program plan. Rule R8-71(g)(2)(iv) requires this information to be included, "if designated by location." Duke has elected not to designate locational allocation within its balancing authority areas for Tranche 1, thus, this information is not required as part of the Program plan. Further, the Commission agrees with the Public Staff that this information should be as detailed as possible and made available to market participants as early as possible. In addition, while the Commission agrees with NCCEBA and NCSEA that the effect of Duke's failure to include this information in the CPRE Program plan is that grid locational guidance cannot be used to eliminate proposals in Tranche 1, the Commission takes a practical view: facilities proposed to be located in areas with "no availability" will require more expensive interconnection facilities and grid upgrades, making these proposals less competitive in the selection process. If, however, after accounting for the interconnection costs and grid upgrade costs, these proposals are below avoided cost and among the most competitive proposals, then the proposals should be selected. Finally, Duke shall continue to refine and update this information through its future CPRE Program plans for Tranches 2-4, as Duke committed to do in its reply comments, and to

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[1] According to Duke's proposed schedule for Tranche 1, which is included in Section 3.4 of the guidelines, the pre-solicitation information will be issued by the Independent Administrator 60 days prior to the RFP release.

make this information as detailed as possible and available as early as possible to facilitate market participants' efforts to prepare and submit proposals.

Issue No. 2: Contracting Period

In Section 2 of Duke's proposed guidelines and Section 2.3 of Duke's proposed initial CPRE Program plan, Duke sets out a proposed planned CPRE RFP Solicitation Schedule, with a 90-day "contracting period" following each bid evaluation period for each tranche or RFP Solicitation. NCCEBA and NCSEA object to the length of the contacting period, suggesting that a 30-day period would be more appropriate given that contracts with CPRE facilities are based on the pro forma PPA. The Public Staff, in general, agreed with NCCEBA and NCSEA that 90 days is an unnecessarily long time period to sign a pro forma PPA contract, but noted that Duke distinguished between bid types in suggesting that asset acquisition proposals could take up to 90 days. In its reply comments, Duke recognizes that pro forma PPAs may be executed in less than 90 days and stated that it will endeavor to expeditiously complete these contracts during a shorter time period. Duke also states that it believes a 90-day contracting period is appropriate for purposes of the Tranche 1 CPRE RFP Solicitation, and stated that it will address whether this period should be shortened or extended for future RFPs in future CPRE Program plans.

The Commission is not persuaded that any modification to the 90-day contracting is justified at this time. The Commission expects Duke to move as expeditiously as possible to execute contracts with facility owners that submitted proposals selected through the RFP Solicitation, as Duke has committed to do in its reply comments.

Issue No. 3: Acceleration of Tranche 4 to July 2020

In Section 2 of Duke's proposed guidelines and Section 2.3 of Duke's proposed initial CPRE Program plan, Duke sets out a timetable for its proposed CPRE RFP Solicitations (Traches 1-4). NCCEBA and NCSEA argue that the issuance date for Tranche 4 should be accelerated by three months to July 2020 to allow projects to start construction in 2021 and thereby qualify for the Solar ITC, which is set to expire on December 31, 2021. This, they argue, will support the goal of the CPRE Program by producing the most cost-effective projects possible. The Public Staff agrees with the notion that it is in the public interest to minimize costs, but states that this consideration must be balanced with the need to maintain grid reliability. The Public Staff believes that the intent behind the statutory requirement that the total 2,660 MW be "reasonably allocated" over 45 months is to maintain grid reliability. The Public Staff also concludes that Duke's proposed 45-month timeline appears reasonable. In its reply comments, Duke states that NCCEBA and NCSEA's proposed acceleration of the Tranche 4 CPRE RFP Solicitation would compress the CPRE procurement to 40 months versus the statutorily required 45 months. Duke further states that it already considered the deadline for the solar ITC in that the proposed schedule forecasts that the Tranche 4 evaluation period to end in May or June 2021 – three months prior to the expiration of the Solar ITC. Finally, Duke notes that the CPRE Program is available to renewable energy facilities that are not solar powered (and, thus, not eligible for the Solar ITC), and cautions that accelerating Tranche 4 raises concerns that Duke would not be able to take into account the downward adjustment in the total 2,660 MW, which is required by G.S. 62-110.8(b)(1).

The Commission agrees with Duke and the Public Staff that Duke's proposed procurement schedule is reasonable and meets the requirements of G.S. 62-110.8(a). The Commission concludes that the concerns expressed by the Public Staff related to grid reliability, and by Duke related to the adjustment required by G.S. 62-110.8(b)(1), have merit and justify approval of the RFP Solicitation Schedule as proposed by Duke . The Commission notes that Duke committed to further evaluate this issue and adjust this schedule, as needed, in a future CPRE Program plan. Therefore, the Commission will remain open to adjustments in the timing of future RFP Solicitations in its review of Duke's future CPRE Program plans and guidelines.

Issue No. 4: Reasonableness of the Market Participant Requirements

In Section 3.2 of its proposed CPRE guidelines, Duke lists 12 "market participant requirements" and provides narrative description of other requirements for market participants. As summarized above, NCCEBA and NCSEA argue that several market participant requirements should be modified and that an additional provision allowing for a five-day cure period should be added to this section. In addition, Duke Renewables argues that Requirement No. 9(b) should be modified to make that requirement applicable to utility-owned facilities only.

NCCEBA and NCSEA argue that Duke should not be allowed to change the generation eligibility requirement from the range of 1 MW and 80 MW that is included in Requirement No. 2. In its reply comments, Duke recognizes that G.S. 62-110.8(a) imposes an upper limit of 80 MW for the generating capacity of a renewable energy facility, correlating to the maximum limit of a small power producer QF under PURPA. However, Duke argues that it should retain flexibility to increase the minimum size requirement of 1 MW if experience demonstrates that these projects are not likely to be successful in the bidding process.

The Commission will reserve judgment on the question of whether Duke is permitted to modify the minimum facility size requirement until such time that Duke proposes to do so.

Next, NCCEBA, NCSEA, and Duke Renewables, argue that Requirement No. 9(b), requiring both utility and non-utility market participants to disclose post-contract term revenue assumptions, is inconsistent with Commission Rule R8-71(l)(4). In response to these comments, Duke agrees to amend this requirement prior to the Tranche 1 CPRE RFP to limit its application only to Duke. To meet its own disclosure requirement, Duke proposes to include an explanation in the updated Tranche 1 guidelines presenting Duke's current assumption that any proposal submitted by Duke as either a self-developed proposal or asset acquisition proposal would continue to receive market based revenues based on a pricing mechanism to be established by the Commission at the conclusion of the initial CPRE Program term. This proposal, Duke argues, would provide the required disclosure while also ensuring reasonable protection of Duke's competitively sensitive proprietary information. The Commission agrees that this requirement should be modified as proposed by Duke in response to the comments of NCCEBA, NCSEA, and of Duke Renewables. The Commission further agrees that Duke can meet the disclosure requirements of Rule R7-71(l)(4) by its proposed modification to this requirement.

NCCEBA and NCSEA further argue that Requirement No. 10 should be revised to require experience developing facilities of the same "renewable energy type" rather than the same "renewable energy technology." Duke did not address this in its reply comments. The Commission concludes that this requirement should be clarified. While NCCEBA and NCSEA's proposed modification is an improvement, the Commission concludes that it also lacks precision. The Commission understands this requirement to mean that a proposal sponsor must show experience developing renewable energy facilities that use the same fuel source and/or electric generation technology as the facility that the proposal sponsor has proposed in the CPRE RFP. Assuming that the Commission's understanding reflects the intent of this requirement, then Duke shall clarify this requirement in its revised guidelines.

NCCEBA and NCSEA also argue that the narrative section following the list of market participant requirements should be modified to include a cure period of five days in the event that the Independent Administrator finds a proposal to be deficient. No other party addressed this issue. The Commission understands this proposed modification to be intended to allow for a limited opportunity to correct clerical errors rather than substantive changes in a proposal. NCCEBA and NCSEA's proposed modification is not entirely clear that the "deficiency" allowed to be corrected is a non-substantive deficiency. The Commission concludes that this proposal is appropriate for inclusion in the market participants requirements section, with modifications. Therefore, Duke shall modify Section 3.2 of the guidelines to include a revised version of the "cure period" provision proposed by NCSEA and NCCEBA. Duke should base its modification on NCCEBA and NCSEA's proposed revision, but make clear that this cure period is for correction of non-substantive deficiencies.

NCCEBA and NCSEA next argue that the provision in Section 3.2 requiring that any proposal sponsor waive any recourse against Duke or the Independent Administrator arising out of the conduct of the RFP is overbroad and should be deleted because a proposal sponsor's right to initiate a proceeding before the Commission should be preserved. The Public Staff agrees, stating that there is no evidence that G.S. 62-110.8 or Commission Rule R8-71 prohibits a bidder's ability to seek recourse for an improperly rejected bid. Duke did not address this issue in its reply comments. The Commission agrees with NCCEBA and NCSEA and the Public Staff and finds this conclusion consistent with the provisions of Commission Rule R8-71(d)(4), and the Commission's explanation of that provision in the CPRE Rule Order. Therefore, Duke shall either delete this provision or modify it to reflect that a market participant has a right to initiate a complaint proceeding before the Commission.

Finally, though not raised by the parties, the Commission addresses two additional issues raised in this section. First, the Commission recognizes the inclusion of Requirement No. 12, prohibiting discrimination based on race, religion, color, national origin, age, sex, or handicap. The Commission concludes this requirement, along with the evaluation factors that include promotion of opportunity for historically underutilized businesses, is appropriately responsive to the Commission's direction in the CPRE Rule Order. Second, the Commission notes that Duke uses the term "Proposal Team" in the narrative introduction to the enumerated requirements. In this context, Duke seems to contemplate one or more market participants partnering with other market participants to form a "Proposal Team," which would be able to meet the enumerated requirements where individually the market participants would not. The Commission determines that the use of the term "Proposal Team" in this context creates ambiguity because "Proposal Team" is defined in the CPRE Rule. Therefore, Duke shall modify this narrative section in a manner that clarifies the intent of this section, and, specifically, shall use a different term than "proposal team" to describe this concept unless Duke intended to use that term as it is defined in the CPRE Rule.

Issue No. 5: Elimination of Asset Transfer Proposal Cost Structure

In Section 3.3 of its proposed CPRE Program guidelines, Duke proposes and defines three "proposal types:" 1) Power Purchase Agreement; 2) Utility Self-developed Facilities; and 3) Asset Acquisition. The Asset Acquisition category includes three different "proposal cost structures:" 1) Renewable resource asset transfer plus EPC; 2) Build Own Transfer; and 3) Renewable Resource Asset.

For reasons summarized above, NCCEBA and NCSEA and Duke disagree about whether the Renewable Resource Asset Transfer proposal cost structure should be eliminated as an Asset Acquisition proposal type. The Commission concludes that Duke has distinguished this proposal cost structure from the other types sufficient to justify its inclusion in Section 3.3 of the guidelines, at least for the Tranche 1 RFP. The Commission will monitor this issue in future program filings and be open to proposals to revise this section in the future. The question of whether these facilities are appropriately included in the utility self-developed proposals that are subject to the 30% limit in G.S. 62-110.8(b)(4) is addressed below.

Issue No. 6: Clarification on how Avoided Cost Rate will be Used

NCCEBA and NCSEA agree with Duke's approach to include DEC and DEP's respective 20-year avoided cost rates using the peaker methodology for Tranche 1, but request additional details on how this will be translated into a rate structure. They argue that if the generic production profile is different from the one used to convert the time-differentiated standard offer tariff into a single all-in PPA price, then it should be included in the guidelines and made available for comment. The Public Staff agrees with this recommendation for Tranche 1, and further suggests that, for future solicitations, the use of more detailed production profiles that fully consider the value of on-peak and off-peak generation may help promote innovative proposals from developers, such as incorporating storage or other technologies to provide more cost-effective options. Duke did not address this issue in its reply comments, but the Commission notes that in Section 3.5.1 of Duke's proposed guidelines, Duke states that for Tranche 1, the avoided costs rates "will be presented in the same rate structure as the Companies' standard avoided cost rates."

The Commission agrees with the comments of the Public Staff, and NCCEBA and NCSEA. Therefore, Duke shall provide additional detail on how the Commission-approved avoided cost rates will be translated into a rate structure in its revised guidelines and in future guidelines and Program plans. Specifically, Duke shall include a similar statement as provided in Section 3.5.1 of the proposed guidelines, addressing whether the required 20-year avoided cost rates are to be presented in the same manner as in Duke's standard avoided cost rates and explain the production model used.

Issue No. 7: Clarification on Application of 30% Limit

The parties' seek guidance on, and raise questions related to, the application of the provisions of G.S. 62-110.8(b)(4), and its 30% limit on the utility's own development of renewable energy facilities. In its petition, Duke raises three issues: 1) voluntarily including PPA proposals offered by a Duke Affiliate as counting toward the 30% limit; 2) application of the 30% limit to the aggregate total obligation of 2,660 MW, rather than to individual RFP Solicitations; and 3) not counting any of the Asset Acquisition Proposals toward the 30% limit. As the Commission has determined that asset acquisition proposals are appropriate for inclusion as a proposal cost structure for the Tranche 1 RFP, the remaining question raised by NCCEBA and NCSEA is whether this proposal type should count toward the 30% limit. The Public Staff does not disagree with Duke's proposed approach to comply with the 30% limit, but recommends that Duke make its design requirements available to the Independent Administrator and prospective bidders as early in the process as possible.

Duke Renewables agreed that clarification of these issues is needed, but argued that NCCEBA and NCSEA's interpretation of these provisions is overly broad and Duke's expansion of the 30% limit may be inappropriate. Duke Renewables suggests that the 30% limit be clarified as follows: 1) the 30% limit should not apply to any project that is "not controlled, directly or indirectly, by the Affiliate," and control should be akin to that definition provided in Securities and Exchange Commission Rule 405 of the Securities Act of 1933; and 2) the only capacity which should count toward the 30% cap is that which is owned by the Affiliate at the time of submission of a bid into any tranche of the CPRE program.

The Commission concludes that, for the Tranche 1 CPRE RFP Solicitation, Duke's voluntary inclusion of PPA proposals offered by Duke's Affiliates as counting toward the 30% limit is appropriate, so long as this voluntary arrangement does not frustrate the goals of the CPRE Program. The Commission further determines that the appropriate time to determine whether a proposal counts toward the 30% limit is the time when the proposal is submitted. Therefore, if Duke or a Duke Affiliate has any ownership interest in a proposal project at the time the proposal is submitted, then the capacity represented by that proposal counts toward the 30% limit. This straightforward approach furthers one of the goals of the CPRE Program, which is to introduce competition into Duke's procurement of energy and capacity supplied by renewable energy facilities. The Commission considered, but declines to adopt Duke Renewables' definition of "control," as it is more complicated and would require additional tracking, reporting, and monitoring of facility ownership within the CPRE Program. The Commission will monitor this issue through its oversight of the CPRE Program, and will consider whether this arrangement remains appropriate in light of the progress Duke makes toward its total CPRE Program procurement obligation. Accordingly, Duke shall provide sufficient detail on facility ownership in its future CPRE Program filings to allow the Commission, the Public Staff, and interested parties to monitor compliance with the 30% limit.

The Commission further determines that Duke's proposal to apply the 30% limit to the total CPRE obligation, rather than to individual RFP Solicitations is appropriate as a more efficient means of monitoring compliance. Applying the 30% limit to the total CPRE obligation seems to make monitoring this limit more straightforward and was supported by the Public Staff. Consistent with the reporting requirements of Commission Rule R8-71, the Commission expects Duke to account for and update the Commission and market participants of the amount of generation that is appropriately included in the 30% limit.

Finally, the Commission finds persuasive Duke's arguments supporting its proposal that asset acquisition proposals should not count toward the 30% limit. The Commission agrees that the plain language of the statute supports this conclusion, because these proposals, as defined by Duke, do not represent procurement through the utility's "own development," but, instead, are "acquired by an electric public utility." See G.S. 62-110.8(b)(4). In short, the Commission determines that in an asset transfer plus EPC cost structure proposal is not utility self-development for purposes of the 30% limit, because the "development" is complete, and only construction, through the performance on the EPC, is required to bring the facility online. This result is consistent with the Commission's determination that the appropriate time to determine whether a proposal counts toward the 30% limit is the time when the proposal is submitted, as explained above.

Issue No. 8: Grouping Study Proposal

In its petition and in Section 4.3 of its proposed guidelines, Duke outlines the need for a "grouping study" process to evaluate potential network upgrade costs as part of Step 1 of the CPRE evaluation process. Duke explains that this process would be a more efficient and coordinated manner of identifying the grid upgrade costs associated with the group of proposals, while adhering to the applicable interconnection procedures.[1] The Public Staff states that it does not object to this proposed grouping study process, and agrees that it will reduce uncertainty, help avoid disputes between parties regarding how system upgrade cost responsibility is assigned, and ensure that the most cost-effective projects are selected. The Public Staff further states that, as long as the evaluation conducted by the Independent Administrator includes the grid upgrade costs associated with the project, only the lowest cost compliance resources that are below avoided cost should be selected.

The Commission disagrees with Duke and the Public Staff that Duke's grouping study proposal is an appropriate means of implementing the evaluation process set out in Commission Rule R8-71(f). Instead, the Commission will rely on its determination made in the CPRE Rule Order that a single track, two-step evaluation process is the appropriate approach. Therefore, Duke shall modify Section 4.3 of its proposed guidelines to be consistent with the Commission's resolution of this issue.

The Commission's starting point is the purpose of the CPRE Program: to add renewable energy to the State's generation portfolio in a manner that allows the State's electric public utilities to continue to reliability and cost-effectively serve customers' future needs. G.S. 62-110.8(a). The General Assembly determined that the appropriate means of achieving this goal is through the competitive procurement of renewable energy, in which Duke, its Affiliates, and other market participants are eligible to participate. The General Assembly also limited the price of a CPRE Program proposal to the utility's avoided costs, and granted Duke authority to manage the costs of adding renewable energy to the State's generation portfolio by designating portions of Duke's electric systems as unavailable to accommodate additional renewable energy facilities, and by controlling and dispatching the output from renewable energy facilities in the same manner it

[1] In its comments, Duke states that it will propose appropriate amendments to the NCIP, as necessary, to accommodate the CPRE Program, in Docket No. E-100, Sub 101.

does its own facilities. To ensure fairness in the bidding evaluation process, the General Assembly required that the program be independently administered by a third-party administrator.

On this background, the Commission determined that the Independent Administrator should conduct step one of the evaluation of proposals without the utility's involvement. In step two, Duke is permitted to eliminate proposals if the utility determines that interconnection and operation of a proposed facility, together with a facility or multiple facilities that were the subject of proposals already selected by the utility, would significantly undermine the utility's ability to provide adequate and reliable electric service to its customers. The Commission adopted Commission Rule R8-71(f)(3) to implement this two-step evaluation process.

The Commission is not persuaded that departure from the approach set out in Commission Rule R8-71(f)(3) is justified for the Tranche 1 CPRE RFP Solicitation. However, the Commission recognizes the difficulties posed by the task of assigning grid upgrade costs to a specific proposal. Therefore, the Commission will clarify its intent in structuring step two of the evaluation of proposals in one narrow aspect: Duke's consideration of system impact should incorporate consideration of grid upgrade costs and make a reasonable assignment of those costs to the proposals submitted, where possible. These costs should be assigned to proposals in a reasonable manner and the proposal price adjusted accordingly. Proposals that require substantial grid upgrade costs to address system impacts will likely be eliminated as being less cost-effective than those that do not (even if the price is below the utility's avoided costs), and those proposals that cannot be accommodated without jeopardizing adequate and reliable electric service to customers should be eliminated on that basis. If Duke determines to eliminate a proposal for either reason, it shall articulate its reasons in the explanation required to be delivered to the Independent Administrator. Thus, to an extent, the Commission is relying on Duke and the Independent Administrator to act in good faith and exercise sound business judgment in completing the difficult task of evaluating grid upgrade costs and assigning those costs to proposals. Within the construct of the Evaluation Team (or through a subset of that team that Duke describes as a "study team"), the evaluation of grid upgrade costs should be completed while maintaining the anonymity of the market participant that submitted the proposal, while preserving the goal of transparency and equity in the evaluation of proposals.

The Commission concludes that allowing Duke to consider grid upgrade costs within the evaluation of system impact is appropriate in light of the goals of the CPRE Program, practical considerations, and the Commission's intent in adopting the CPRE Rule. As Duke acknowledges in Section 4.3 of its guidelines, "the goal of the CPRE RFP Solicitation is to procure renewable energy facilities that are cost effective, which likely will entail having little to no upgrade costs associated with their size and location." The Commission agrees. Further, because Duke evaluates system impact in step two of the proposal evaluation process, this is also the appropriate time to identify grid upgrade costs. Introducing the evaluation of grid upgrade costs into step one, through the grouping study process Duke proposes, seems unnecessarily complex and likely to lead to delays in the ultimate award of proposals during the initial 45-month procurement period. For the Tranche 1 RFP, the Commission is prepared to move forward with the evaluation process established in Commission Rule R8-71(f), as clarified herein. Further, the Commission continues to recognize "that opportunities for improvements may arise or become apparent after there is a sufficient historical record of working through the process. Therefore, the Commission will remain open to these opportunities in the future." CPRE Rule Order at 17.

Therefore, Duke shall modify Section 4 of its guidelines to eliminate any utility involvement in step one of the evaluation process, and to add consideration of grid upgrade costs to step two of the evaluation process as a part of evaluating system impact. The grouping study process proposed by Duke and agreed to by the Public Staff would be an appropriate means of evaluating grid upgrade costs within Duke's responsibilities in step two of the proposal evaluation. These modifications should be consistent with Commission Rule R8-71(f)(3) and the Commission's discussion of that provision in the CPRE Rule Order. In addition to requiring Duke to address grid upgrade costs, as necessary, in its explanation of the elimination of proposals, Duke shall report on grid upgrade costs on a per-proposal basis in its future CPRE compliance reports.

Issue No. 9: Cost Recovery

Pursuant to subsection G.S. 62-110.8(g):

> An electric public utility shall be authorized to recover the costs of all purchases of energy, capacity, and environmental and renewable attributes from third-party renewable energy facilities and to recover the authorized revenue of any utility-owned assets that are procured pursuant to this section through an annual rider approved by the Commission and reviewed annually....The annual increase in the aggregate amount of these costs that are recoverable by an electric public utility pursuant to this subsection shall not exceed one percent (1%) of the electric public utility's total North Carolina retail jurisdictional gross revenues for the preceding calendar year.

The Commission adopted Commission Rule R8-71(j) to implement this provision.

In its petition, Duke states that it has determined that jointly issuing CPRE RFP Solicitations will be more efficient and will ensure consistency in the evaluation and contracting process. However, Duke further states that DEC and DEP will continue to independently meet their CPRE planning, reporting, and cost recovery obligations under the CPRE Rule. Specific to cost recovery, DEC and DEP will separately contract with the market participants that submit proposals that are selected and each utility will be independently responsible for the full cost of renewable energy resources procured within its service territory to comply with the CPRE Program requirements. The Commission determines that Duke's proposed approach is appropriate and should be approved.

Also included in Duke's petition is its description of a proposal to recover "network upgrade costs" through future adjustments to Duke's general rates. Duke supports this proposal by explaining that the goal of the CPRE RFP Solicitation is to competitively procure renewable energy facilities that are cost effective, and proposals selected through the RFP will likely entail little to no upgrade costs, depending on each proposal's size and location. Duke further explains that the timeframe for proposal submission will precede the System Impact Study and Facilities Study steps in the NCIP and SC GIP, through which Duke analyzes and determines the detailed cost of interconnection facilities and network upgrade costs. In addition, Duke states that while the cost of interconnection facilities between the generation facility and the point of interconnection can reasonably be predicted, network upgrade costs beyond the point of interconnection can vary dramatically depending on the grid's capability to integrate additional generation at the requested point of interconnection. Thus, this construct of the CPRE Program, Duke states, exposes market participants to unknown and potentially significant network upgrade costs. To mitigate this risk, Duke proposes segregation of network upgrade costs and proposal costs, with the market participant being required to include proposal costs in its proposal price and DEC and DEP separately applying to recover network upgrade costs through a future general rate case proceeding.

The Public Staff responded to Duke's proposed cost recovery method stating that it prefers the traditional approach where all interconnection costs are assigned to the interconnection customer, but, in light of the practical challenges with isolating grid upgrade costs for project assignment, the Public Staff does not object to Duke's proposal for use in the Tranche 1 CPRE RFP Solicitation. In addition, the Public Staff recommends that the Commission require DEC and DEP to file reports detailing all grid upgrades resulting from each CRPE Solicitation, along with the costs associated with grid upgrades, as a part of the annual CPRE compliance report.

NCCEBA and NCSEA expressed support for Duke's proposed cost recovery method.

In response to the Public Staff's comments, Duke suggests that the Commission approve its cost recovery method, but provide that the Commission base its decision on "unique 'practical challenges' and circumstances of the CRPE RFP and shall not be viewed as precedential for QFs seeking to sell" to Duke under PURPA.

The Commission appreciates the Public Staff's attention to this issue and its having noted the Commission's historical approach to cost recovery that emphasizes, to the extent possible, recovery of interconnection costs through the Commission-approved interconnection fees that are charged to a generation facility. In its prior orders addressing this subject, the Commission anticipated that some costs might be so diffuse, or because the costs were incurred after interconnection, assignment to an interconnection customer would be difficult or impossible. The Commission's prior orders have contemplated that these costs might be appropriately recovered through base rates. The Commission determines that the network upgrade costs, as defined by Duke in its CPRE filings, are exemplary of the types of costs that might be appropriately recovered through an adjustment in base rates. Further, as the Public Staff observed, a general rate case would allow an appropriate amount of time for the Public Staff to review these costs and the Commission to determine whether these costs were reasonably and prudently incurred. Finally, the Commission agrees with Duke that the unique circumstances of implementing the CPRE Program on the timeline that the General Assembly has directed the Commission to do, justify a unique approach. Therefore, the Commission concludes that Duke's proposed cost recovery is appropriate and should be approved.

Issue No. 10: Curtailment Provisions of the PPAs

In its Petition, Duke addresses the provisions of the pro forma PPA that include "control instructions," which allow Duke to dispatch, operate, and control the solicited renewable energy facilities in the same manner as Duke's own generating resources. These provision include an annual threshold for curtailment equivalent to 5% of expected annual output in DEC and 10% of expected annual output in DEP. Above these thresholds the CPRE PPA would require Duke to pay the facility owner at the full contract price for each MWh of energy that could have been generated, but was not due to the dispatch down control instruction. Duke argues that these provisions are reasonable and meet the CPRE Program objectives.

NCCEBA and NCSEA object to implementing different curtailment thresholds for DEC and DEP, and offer two alternative options that they argue provides more certainty for market participants, allows flexibility for Duke in curtailment, and results in lower costs for ratepayers. In the first alternative, NCCEBA and NCSEA suggest treating the CPRE facility as a rate-based utility asset, and, in the second alternative, curtailment would be treated as a service and the CPRE facility would be paid a curtailment service fee equal to the PPA rate.

The Public Staff states that it does not take issue with Duke's proposed dispatch and curtailment provisions, but emphasizes that this authority further heightens the need for Duke to have non-discriminatory and transparent procedures in place for curtailment resulting from control instructions. The Public Staff also recommended that curtailment of CPRE resources should be included in the quarterly reports that DEC and DEP must file as a result of the Commission's Avoided Cost Order. In addition, the Public Staff suggests that it is important that curtailment estimates used in evaluation of asset acquisition or utility self-developed proposals be comparable to those included in the third-party PPA proposals.

In response to the Public Staff's comments, Duke agrees to include the curtailment of CPRE facilities in its quarterly reports, for those CPRE facilities that are curtailed due to emergency conditions or force majeure events. Duke distinguishes these circumstances from the CPRE dispatch down instructions, which Duke states "are likely to be more routinely issued" as a part of normal system operations. Duke does not agree to include these curtailment instances in its quarterly reports addressing emergency condition curtailments. In response to the Public Staff's comments suggesting that there should be parity between the curtailment of asset acquisition or utility self-developed proposals and third-party PPA proposals, Duke states that this is not anticipated to be a material issue because Duke plans to impose the same dispatch priority on all generators selected through a CPRE RFP Solicitation, regardless of proposal type. Duke argues that this approach aligns with G.S. 62-110.8(b), which provides that the utility the "rights to dispatch, operate, and control the solicited renewable energy facilities in the same manner as the utility's own generating resources."

The Commission first determines that Duke's proposed curtailment thresholds included in its pro forma PPAs (5% for DEC and 10% for DEP) are appropriate for use in Tranche 1. Without revisiting the entirety of the Commission's 2016 biennial avoided cost proceeding (Docket No. E-100, Sub 148), the Commission determines that the disparity in the presence of distributed resources between DEC and DEP justifies the disparate curtailment thresholds. The Commission is not prepared to approve NCCEBA and NCSEA's alternative methods of dealing with curtailment and compensation on this record, but will monitor this issue and remain open to changes in the future, as is further discussed below in the context of considering the pro forma PPA. Finally, the Commission agrees with the Public Staff as to the importance of non-discriminatory and transparent procedures in place for curtailment of CPRE facilities. To facilitate the Commission's oversight of Duke's implementation of the CPRE Program, as required by G.S. 62-110.8, Duke shall submit reports on the curtailment of CPRE Program facilities as part of its reporting, and this report shall include a comparison with the curtailment of Duke's own facilities. Duke shall also include curtailment of CPRE facilities for emergency conditions or force majeure in its reports required by the Avoided Cost Order, as it agreed to do.

Issue No. 11: Waiver of Regulatory Conditions and Code of Conduct Requirements

In its petition and as Attachment 4 thereto, Duke requests that the Commission grant it a waiver of several Regulatory Conditions and Code of Conduct Requirements. Generally, and as summarized above, these provisions restrict Duke's ability to transfer payments, goods and services, cost allocation, and trade secret information between DEC and DEP (as electric public utilities) and affiliated companies.

In its report and comments, the Public Staff states that it reviewed these proposed waivers and believes that they are reasonable and appropriate for the purposes of implementing the CPRE Program.

No other party addressed Duke's requested waivers.

The Commission reviewed Duke's requested waivers in light of the provisions of the CPRE Program and the CPRE Rule, and agrees with Duke and the Public Staff that these waivers are reasonable and appropriate for the purpose of implementing the CPRE Program. Therefore, Duke's requested waivers should be approved.

Issue No. 12: Reasonableness of the Provisions of the pro forma PPA

Duke included as Attachment 2 to its Petition the pro forma PPA required to be filed for Commission approval pursuant G.S. 62-110.8(b)(3) and Commission Rule R8-71(c)(v). In support of its request for approval of the pro forma PPA, Duke states that the terms and conditions of the Tranche 1 CPRE PPA are commercially reasonable and are substantively the same as the current negotiated PPA utilized by Duke. Duke further states that over the past three years these terms and conditions have been accepted by 15 counterparties for 28 projects, representing 1,300 MW of renewable energy capacity. In addition, Duke alerts the Commission, as directed in the CPRE Rule Order, that Duke may seek to modify the terms and conditions prior to the initial CPRE RFP Solicitation date. Consistent with Commission Rule R8-71(f)(1)(iii), the Commission anticipates receipt of Duke's filing of the pro forma PPA as part of the pre-Solicitation filing, including identification of any such modifications, and that the Independent Administrator would include this document in the pre-solicitation information.

In their comments, NCCEBA and NCSEA object to a number of provisions included in the pro forma PPA, and included as attachments to its comments a redline version of the pro forma PPA. NCCEBA and NCSEA outline their arguments in support of their proposed changes, described as the "most significant amendments." NCCEBA and NCSEA urge the Commission not to apply any presumption of reasonableness based on Duke's statement that the pro forma PPA based on its past use in the negotiated contract setting. NCCEBA and NCSEA note that the Commission has a statutory mandate to review and approve the pro forma PPA and emphasize the importance of eliminating unnecessarily burdensome contract terms that may require market participants to increase their pricing to compensate for the impact of those terms.

In its reply comments the Public Staff states that its initial review of the pro forma PPA did not raise significant concerns; however, in light of NCCEBA and NCSEA's comments the Public Staff recognizes that some of the provisions in the PPA may create challenges for market participants seeking to obtain financing for projects. Specifically, the Public Staff agrees with the inclusion of a provision allowing a reasonable opportunity to cure non-material breaches. In addition, the Public Staff states that prior to including the pro forma PPA in the Tranche 1 pre-solicitation filings, further information sharing between NCCEBA, NCSEA, Duke, the Public Staff, and other parties regarding the additional concerns raised would help clarify and potentially resolve these concerns.

Duke responded to NCCEBA and NCSEA's objections to the terms and conditions of the pro forma PPA, by first disagreeing that the terms and conditions are commercially unreasonable. Duke reiterates that the pro forma PPA is based on a PPA that has been accepted by a number of counter parties, and argues that this demonstrates the reasonableness of the PPA. Duke next raises a general objection to "NCCEBA/NCSEA's attempt to negotiate almost 40 different clauses and terms of the CPRE PPA through the regulatory process" prior to the Tranche 1 CPRE RFP Solicitation, and suggested that if a specific term is viewed unfavorably then that feedback should be provided through the solicitation process managed by the Independent Administrator. Duke further objects to the Commission acting as arbiter of the commercial reasonableness of each and every term in the pro forma PPAs, arguing that commercial reasonableness of the PPA should be left to the contracting parties and that NCCEBA and NCSEA have failed to present any compelling reasons to deviate from the terms as proposed or the process used to inform market participants. Finally, Duke states that DEC and DEP have historically been amenable to minor negotiated revisions to their form PPAs, but, as provided in the proposed CPRE guidelines, Duke has proposed not considering amendments to the CPRE PPA to ensure all parties contract on the same terms. However, Duke nonetheless commits to further evaluate whether specific NCCEBA and NCSEA revisions are appropriate for Tranche 1, and whether to modify its approach to allow for limited negotiations. Duke also commits to "transparently address these issues through the CPRE pre-solicitation process," and then file the CPRE pro forma PPA with the Commission at least 30 days prior to the CPRE RFP Solicitation issuance date, as required by G.S. 62-110.8(b)(3) and Commission Rule R8-71(f)(1)(iii).

The Commission first rejects Duke's arguments that the Commission should not be the arbiter of the commercial reasonableness of the terms of the pro forma PPA. The Commission has a statutory mandate to review and approve the terms and conditions of the pro forma PPA. G.S. 62-110.8(b)(3). However, the Commission accepts Duke's representations that the pro forma PPA is similar to contracts that have been accepted in negotiations with owners of renewable energy facilities as supporting approval of the pro forma PPA. Likewise, the Commission accepts NCCEBA and NCSEA's representations that some provisions of the pro forma PPA may create challenges for market participants seeking to obtain financing as supporting modification to the pro forma PPA terms. Further, the Public Staff independently agreed with the validity of some of NCCEBA and NCSEA's concerns, and suggested that further conversations among the parties might be productive. Finally, the Commission appreciates Duke's willingness to further evaluate whether specific revisions or limited negotiations on the terms of CPRE PPAs are appropriate, and Duke's commitment to transparently address these issues within the CPRE pre-solicitation process.

The Commission determines that practical considerations related to the timing of the filings in this proceeding, the approaching Tranche 1 RFP Solicitation issuance date, and the relatively brief 45 months in which Duke must meet its total CPRE obligation, justify allowing Duke to proceed to the Tranche 1 CPRE RFP Solicitation issuance as proposed in its reply comments. In short, the Commission is not prepared to approve or reject NCCEBA and NCSEA's proposed revisions to the pro forma PPA on this timeframe or this record. Therefore, the Commission approves the use of the pro forma PPA as proposed by Duke for the purposes of the Tranche 1 CPRE RFP Solicitation only, and directs Duke to proceed toward the Tranche 1 CPRE RFP Solicitation issuance as proposed in its reply comments, including further evaluating whether specific revisions or limited negotiations are appropriate. Duke shall update the Commission, the Public Staff, and market participants through its pre-solicitation filings and its proposed information sharing process. In addition, as the Public Staff recommends, Duke, NCCEBA, NCSEA, the Public Staff, and other parties should continue to discuss the reasonableness of the provisions of the pro forma PPA with the goal of reaching consensus on revisions. Duke shall specifically address the result of these discussions in the September filings required under the CPRE Rule. As with other issues raised in this proceeding, the Commission will continue to monitor developments and expects the parties to alert the Commission if the terms and conditions of the pro forma PPA are a barrier to achieving the goals of the CPRE Program.

Conclusion

Based upon the foregoing and the entire record in this proceeding, the Commission concludes that Duke's initial CPRE Program guidelines and initial CPRE Program plan should be modified to conform with the conclusions reached in this order. With these modifications, the initial CPRE Program guidelines and initial CPRE Program plan meet the requirements of Commission Rule R8-71 and are reasonably designed to achieve the mandates and objectives of G.S. 62-110.8. Therefore, Duke shall file updated versions of the initial CPRE Program guidelines and initial CPRE Program plan as part of the established pre-Solicitation filing requirement and information sharing process. The Commission further concludes that Duke's requested waivers of regulatory conditions and code of conduct requirements are reasonable and, therefore, should be granted. Finally, the Commission concludes that Duke should be required to incorporate the additional reporting requirements discussed in this order as part of Duke's September 1, 2018, CPRE filings.

IT IS, THEREFORE, ORDERED as follows:

1. That Duke shall modify its initial CPRE Program guidelines and initial CPRE Program plan to conform to the conclusions reached in this order;

2. That Duke's initial CPRE Program guidelines, as modified in compliance with this order, shall be, and are hereby, approved for use in the Tranche 1 CPRE RFP Solicitation;

3. That Duke's initial CPRE Program plan, as modified in compliance with this order, shall be, and is hereby, accepted;

4. That Duke's proposed pro forma PPA shall be, and is hereby, approved for use in the Tranche 1 CPRE RFP Solicitation. Duke shall continue its discussions with NCCEBA, NCSEA, the Public Staff, and other interested parties regarding potential revisions to the pro forma PPA or limited opportunity for negotiations on terms and conditions, as Duke proposed in its reply comments filed in this proceeding;

5. That Duke's requested waivers of regulatory conditions and code of conduct requirements shall be, and are hereby, granted; and

6. That Duke shall incorporate into its future CPRE Program filings the additional reporting requirements required by this order.

ISSUED BY ORDER OF THE COMMISSION.
This the 21st day of February, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. E-2, SUB 1159
DOCKET NO. E-7, SUB 1156
DOCKET NO. E-100, SUB 157

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

Docket No. E-2, SUB 1159 Docket No. E-7, SUB 1156 In the Matter of Joint Petition of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, for Approval of Competitive Procurement of Renewable Energy Program Docket No. E-100, SUB 157 In the Matter of 2018 Biennial Integrated Resource Plans and Related 2018 REPS Compliance Plans	)	ORDER REQUIRING INTERIM CPRE PROGRAM REPORTS, ALLOWING INTERIM IMPLEMENTATION OF CPRE PROGRAM PLANS, AND ESTABLISHING SCHEDULE FOR FILING OF COMMENTS

BY THE COMMISSION: On September 5, 2018, in Docket No. E-100, Sub 157, Duke Energy Carolinas, LLC (DEC), and Duke Energy Progress, LLC (DEP) (together, Duke), filed updates to their Competitive Procurement of Renewable Energy (CPRE) Program Plan, as part of their 2018 biennial integrated resource planning (IRP) reports.

On October 5, 2018, in Docket Nos. E-100, Sub 101, E-2, Sub 1159, and E-7, Sub 1156, the Commission issued an Order Approving Interim Modifications to North Carolina Interconnection Procedures for Tranche 1 of CPRE RFP. Among other things, that Order allowed parties to file comments related to the timing of consideration of potential changes to the administration of the CPRE Program.

On November 5, 2018, Duke filed a letter in response to the Commission's request for comments. In its letter, commits to work with the Independent Administrator to identify "lessons learned" from the Tranche 1 CPRE RFP Solicitation and to provide the Commission with interim reports on a schedule detailed in the letter.[1]

Also on November 5, 2018, the Public Staff filed comments. The Public Staff states that it supports the schedule of reports proposed by Duke in its letter and further recommends that the initial interim report include price information, with appropriate treatment if that information is considered confidential.

Based upon the foregoing and the entire record herein, the Commission finds good cause to require the filing of the interim reports regarding the status and results of the Tranche 1 CPRE RFP Solicitation, as proposed by Duke, and to require the inclusion of the price information in those reports, as recommended by the Public Staff. In addition, it appears that there is uncertainty about which CPRE Program plan and Guidelines that Duke is, or should be, operating under at this time: the initial CPRE Program plan that the Commission approved in February 2018 for use in the Tranche 1 CPRE RFP Solicitation, or the proposed CPRE Program plan that Duke filed with its 2018 biennial IRP filing. Therefore, the Commission further finds good cause to resolve this uncertainty by allowing Duke to implement the CPRE Program plan filed with its 2018 biennial IRP filing on an interim basis while the Commission receives comments on that plan. Finally, the Commission finds good cause to direct the parties who desire to provide comments on Duke's proposed CPRE Program plans to do so in Docket Nos. E-2, Sub 1159, and E-7, Sub 1156, and not in Docket No. E-100, Sub 157.

IT IS, THEREFORE, ORDERED as follows:

1. That Duke Energy Carolinas, LLC and Duke Energy Progress, LLC shall file with the Commission interim reports regarding the status and results of the Tranche 1 CPRE RFP Solicitation on the schedule proposed in its letter filed with the Commission on November 5, 2018. These interim reports shall include the pricing information as recommended by the Public Staff in its comments that were also filed with the Commission on November 5, 2018;

2. That Duke Energy Carolinas, LLC and Duke Energy Progress, LLC shall be, and are hereby, authorized to implement the CPRE Program plans filed with the Commission on September 1, 2018, on an interim basis, including the scheduled opening of the Tranche 2 CPRE RFP Solicitation in July 2019 and other adjustments to the proposed schedule of RFP Solicitations. This authorization shall be without prejudice as to the right of any party to file comments with the

[1] On December 7, 2018, the first of these reports was filed with the Commission in Docket Nos. E-7, Sub 1159, and E-2, Sub 1156.

Commission regarding the CPRE Program plans, or the Commission to order changes in the CPRE Program plans;

3. That any party to these proceedings that desires to present comments to the Commission on the CPRE Program plans filed with the Commission on September 1, 2018, shall file their comments in Docket Nos. E-2, Sub 1159, and Docket No. E-7, Sub 1156, as follows:

a. On or before January 31, 2019, all parties may, and the Public Staff shall, file initial comments on the CPRE Program plans filed with the Commission on September 1, 2018, in Docket No. E-100, Sub 157. These comments may also address or respond to the interim reports required by Ordering Paragraph No. 1 of this Order;
b. On or before March 29, 2019, all parties may file reply comments addressing the other parties' initial comments on the CPRE Program plans filed with the Commission on September 1, 2018, in Docket No. E-100, Sub 157. These comments may also address or respond to the interim reports required by Ordering Paragraph No. 1 of this Order;
c. Upon receipt of the interim reports that are required by this Order and of the parties' initial comments, and reply comments, the Commission will proceed appropriately in considering the updates to the CPRE Program plans; and

4. That the Chief Clerk shall transmit a copy of this Order to the parties to the proceedings in Docket No. E-100, Subs 101.

ISSUED BY ORDER OF THE COMMISSION.
This the 17th day of December, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. E-2, SUB 1167
DOCKET NO. E-7, SUB 1166

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Progress, LLC,	)	ORDER MODIFYING AND
and Duke Energy Carolinas, LLC, Requesting	)	APPROVING RIDERS
Approval of Solar Rebate Program Pursuant to	)	IMPLEMENTING SOLAR
G.S. 62-155(f)	)	REBATE PROGRAM

BY THE COMMISSION: On July 27, 2017, House Bill 589 (S.L. 2017-192) was enacted into law. Part VIII of House Bill 589, enacted in part as G.S. 62-155(f), requires Duke Energy Progress, LLC (DEP), and Duke Energy Carolinas, LLC (DEC) (collectively, Duke or the Companies), to file with the Commission an application requesting approval of a program that offers reasonable incentives to residential and nonresidential customers for the installation of small customer-owned or leased solar energy facilities. Pursuant to G.S. 62-155(f), participants in an approved solar rebate program also will participate in the offering utility's net metering tariff, with an incentive limited to 10 kW_{AC} for residential solar installations and 100 kW_{AC} for nonresidential solar installations.

On January 22, 2018, prior to the 180-day filing deadline imposed by Section 8.(c) of House Bill 589, DEC and DEP jointly filed an application seeking approval of the Companies' proposed solar rebate program, made available through DEC's Solar Rebate Rider SRR and DEP's Solar Rebate Program Rider SRP (collectively, Solar Rebate Rider). Also included in the filing are forms for customers to apply for service under the Solar Rebate Rider.[1]

On January 26, 2018, the Commission issued an Order Establishing Proceeding to Review Duke's Proposed Solar Rebate Program. That Order recognized the participation of the Public Staff – North Carolina Utilities Commission (Public Staff), and set a schedule for receipt of petitions to intervene, initial comments, and reply comments.

Pursuant to G.S. 62-155(f), the incentives offered through a solar rebate program should comport with the following requirements:

(1) Shall be limited to 10,000 kW of installed capacity annually starting on January 1, 2018, and continuing until December 31, 2022, and shall provide incentives to participating customers based upon the installed alternating current nameplate capacity of the generators.

(2) Nonresidential installations will also be limited to 5,000 kW in aggregate for each of the years of the program.

(3) Of the capacity for nonresidential installations, 2,500 kW shall be set aside for use by nonprofit organizations; 50 kW of the set-aside shall be allocated to the NC Greenpower Solar Schools Pilot or a similar program. Any set-aside rebates that are not used by December 31, 2022, shall be reallocated for use by any customer who otherwise qualifies. For purposes of this section, "nonprofit organization" means an organization or association recognized by the Department of Revenue as tax exempt pursuant to G.S. 105-130.11(a), or any bona fide branch, chapter, or affiliate of that organization.

(4) If in any year a portion of the incentives goes unsubscribed, the utility may roll excess incentives over into a subsequent year's allocation.

On or after January 30, 2018, the Commission issued orders allowing North Carolina Sustainable Energy Association (NCSEA) and the Southern Alliance for Clean Energy (SACE) to intervene in this proceeding.

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[1] As a preliminary matter, there is no material, substantive difference between DEC's Solar Rebate Rider SRR and DEP's Solar Rebate Program Rider SRP. The Commission, therefore, refers collectively and singularly throughout this Order to Duke's proposed Solar Rebate Rider.

On February 9, 2018, the Public Staff, SACE, and NCSEA filed initial comments. On February 16, 2018, Duke and SACE filed reply comments.

On March 14, 2018, Rishipal Bansode, Ph.D., filed a consumer statement of position stating that North Carolina residents who elected to install solar panels in 2017 are disadvantaged because they neither were able to avail themselves of the North Carolina renewable exergy tax credit, which expired on January 1, 2017, nor will they be eligible to apply for the Solar Rebate Rider. Dr. Bansode requests that the Commission require Duke to consider as eligible any qualifying system installed on or after January 1, 2017.

Duke's Application

Duke contends that its proposed solar rebate program, made available through its Solar Rebate Rider, offers reasonable incentives through one-time, upfront payments to eligible customers who install an approved solar energy facility. More specifically, Duke proposes that on or before April 1, 2019, and each calendar year thereafter, it will file with the Commission a report providing participation rates by customer class, the number of applications rejected, the number of applications canceled at year's end, and the program costs incurred to date. Second, Duke commits to publish on its website and file with the Commission a notice when prescribed participation levels in the Solar Rebate Rider reach capacity. Third, Duke reiterates the parameters imposed by G.S. 62-155(f)(1)-(4), as set forth above. Fourth, Duke proposes that any unsubscribed capacity, regardless of a prior set-aside requirement, will be available to any otherwise eligible customer beginning on January 1, 2023. Fifth, Duke proposes that it will retain the renewable energy certificates for any customer receiving service under a non-time of use demand rate schedule. To receive a rebate payment following approval of a customer's application and installation of a customer-owned or leased solar photovoltaic (PV) system, the customer must submit to Duke a certificate of completion indicating that the installation is complete and confirming that billing under an eligible rate schedule and net metering rider has commenced. Duke reserves the right to inspect and verify any solar PV system installation for which a rebate has been approved. Duke further proposes the following rebate amounts for each eligible participant class: (1) nonresidential customers will receive $0.50 per watt, (2) residential customers will receive $0.60 per watt, and (3) non-profit customers will receive $0.75 per watt. Sixth, Duke proposes a contract period of ten years for service under the Solar Rebate Rider, which could thereafter be renewed for successive one-year periods, unless terminated by Duke.[1] Absent "good cause as determined by [Duke]," early termination of service under the Solar Rebate Rider will result in a charge derived from the following calculation:

Early Termination Charge = (1 - (# of participating months / 120)) * rebate payment amount

Seventh, Duke reserves the right to terminate service under the Solar Rebate Rider at any time upon written notice to the customer if: (1) the customer violates any terms of service; (2) the service is detrimental to Duke or its customers; or (3) a customer is found to have misstated or misrepresented the information conveyed to Duke in the Solar Rebate Rider application process. Duke also reserves the right to request repayment of the solar rebate amount paid when a customer

[1] In its reply comments, Duke reports that it has agreed to strike this provision following discussions with the Public Staff.

is found to have intentionally misstated or misrepresented information in the Solar Rebate Rider application process. Eighth, Duke reserves the right, at its own cost, to install, operate, and monitor any special equipment or metering necessary to record 100% of the customer's generator output.

Next, Duke proposes the following Solar Rebate Rider application criteria, rules, and restrictions: (1) previously rejected applicants are eligible to reapply, subject to all other eligibility criteria; (2) all applications that remain pending at the end of a given calendar year will be rejected and cancelled; (3) applications for a given calendar year may be submitted no earlier than January 1 of the applicable year; (4) applications for a solar PV system installed in the previous calendar year will be accepted only to the extent that the installation occurred within 90 days preceding the submission date of the current application; (5) the nameplate capacity in alternating current constitutes the determinative capacity for which the rebate can be calculated; and (6) eligibility for service under the first year of the Solar Rebate Rider is limited, subject to Duke's discretion, to those solar PV systems installed on or after January 1, 2018. Customers also may apply for a rebate reservation in advance of installation. For residential customers who reserve a rebate, installation must be completed within 365 days after the date Duke issues such reservation. For nonresidential customers who reserve a rebate, installation must be completed within 365 days after the date Duke executes the interconnection agreement. Duke's proposed application forms require the applicant to provide the following information: (1) customer name, (2) customer account number, (3) e-mail address, (4) project identification, (5) facility address, (6) payment address, (7) installer name, (8) installer address, (9) projected/installed kW_{DC}/kW_{AC}, (10) kW_{AC} eligible for the solar rebate, (11) solar rebate calculation, (12) projected solar rebate payment, (13) the installer's name and dated signature, and (14) the customer's name and dated signature. Finally, the application forms contain sixteen standard contract terms and conditions, most of which already have been mentioned in this summary of proposed Solar Rebate Rider rules, but those which are specifically objected to by one or more of the intervening parties, are set forth below.

SUMMARY OF INITIAL AND REPLY COMMENTS

Public Staff

In its comments, the Public Staff states that it "agrees that [Duke's] application generally complies with the requirements of G.S. 62-155(f)," and "that the rebate structure and amounts proposed by the utilities for residential, nonresidential, and non-profit customers are reasonable and designed to incentivize" installation of customer-owned or customer-leased solar PV systems. The Public Staff also notes that it has requested from Duke information regarding total cost recovery of the rebates issued through, and administrative costs of, the Solar Rebate Rider, and will either continue those discussions in the instant proceeding or in the respective cost recovery proceedings for each utility pursuant to G.S. 62-133.8(h).

NCSEA

In its comments, NCSEA states that it generally supports the Solar Rebate Rider. NCSEA contends, however, that there exist some areas for improvement. First, NCSEA takes exception to Duke's proposal to "base the rebate on the nameplate capacity of the inverter and not on the generation capacity of the solar energy facility." NCSEA expresses concern that such a policy would allow a residential customer to pair, for example, a 1-kW_{DC} solar PV system with a 10-kW_{AC}

inverter and receive an artificially inflated rebate, specifically a $6,000 instead of a $600 rebate. To reduce the likelihood of such a scenario, NCSEA suggests that Duke should "use a fixed conversion factor for converting the DC generating capacity of installed solar panels to AC for purposes of rebate eligibility." NCSEA concedes that Duke in its proposal reserves the right to inspect or verify the accuracy of all information provided to it by the customer, with certain available recourse in the event of a misstatement or misrepresentation, including rejection of an application, termination of existing service under the Solar Rebate Rider, or a request for repayment of the rebate amount if a customer is found to have intentionally misstated or misrepresented information to Duke. Nonetheless, NCSEA contends that these remedies are insufficient to protect customers from some solar energy facility installers whose misdeeds could result in early termination of a customer's service under the Solar Rebate Rider, in addition to the imposition of a corresponding early termination charge.

Second, NCSEA suggests that the Solar Rebate Rider should allow for assignment to third parties of solar rebate payments. This, NCSEA contends, would put solar PV system installers "in a better position to 'float' the capital investment during the period of time between when a solar energy facility is installed and when the rebate payment is issued by Duke." NCSEA states that Duke appears to be capable of allowing such third-party assignment of rebate payments, given that Duke's South Carolina solar rebate program allows for the same. NCSEA further argues that Duke's proposal to remit payment of the solar rebate directly to the customer, even when the solar PV system is leased, is problematic because the lessee in such a scenario would receive the solar rebate payment, despite the lessor owning the system and having made the upfront capital expenditure. Instead, NCSEA suggests that Duke should remit the rebate payment directly to the owner of the system for which the solar rebate is issued.

Finally, NCSEA suggests that Duke's proposed Solar Rebate Rider application forms should provide better clarity regarding the methods by which applications can be submitted, including whether applications will be accepted electronically and if any supporting documentation is needed. NCSEA further suggests that Duke should provide customers "with a realistic expectation of how quickly Duke will issue rebate payments" and "clarify whether businesses that receive electric service at multiple locations are eligible for multiple rebates if they install solar energy facilities at more than one location." NCSEA proposes that Duke should make the rebate application process available online, preferably through its PowerClerk program that is used for interconnecting small solar energy facilities. In addition, NCSEA requests that information "about the quantity of rebates claimed and remaining on a close to real time basis" should be provided by Duke on its website on at least a monthly basis, as is the case with Duke's solar rebate program in South Carolina. Finally, NCSEA asks the Commission to "direct Duke to include in its annual report filing an examination of whether rebate values continue to be appropriate for market conditions in future years."

SACE

In its initial comments, SACE first takes issue with Duke's proposed eligibility requirement that a solar PV system must have been installed no more than 90 days prior to submission of an application for service under the Solar Rebate Rider (90-Day Rule). SACE more specifically objects to this eligibility requirement as it applies to those qualifying customers who have installed an otherwise eligible solar PV system, but who are required to reapply in a subsequent calendar year due to the annual participation limit already having been reached in the year in which the application was first submitted. For such applicants, suggests SACE, Duke should use the dates of the original application submission and project completion to determine compliance with the 90-Day Rule. Second, SACE contends that Duke should use the date of this Order as the installation date for any customers who installed a solar PV system after January 1, 2018, but prior to issuance of this Order.

SACE next expresses concern regarding House Bill 589's directive to Duke, pursuant to G.S. 62-126.4, that it shall file revised net metering rates for electric customers. SACE contends that a revision to existing net metering rates could affect the reasonableness and value of the incentives provided by Duke through the Solar Rebate Rider. Therefore, SACE suggests that any such future changes to net metering rates may warrant the Commission's re-evaluation of the Solar Rebate Rider.

Similar to NCSEA, SACE suggests that Duke should provide information on its website regarding progress made toward annual participation caps before such caps already have been reached. Specifically, SACE recommends that the Commission should require, as it does for progress made toward the capacity limits of electric generator lessors, incremental notice of 25%, 50%, 75%, and 100% of annual participation limits reached under the Solar Rebate Rider.[1] Alternatively, as NCSEA also suggests, SACE points out that Duke provides monthly status updates regarding the progress made toward participation caps as part of its administration of the South Carolina solar rebate program.

Also similar to NCSEA, SACE expresses concern regarding the inability for customers who lease a solar PV system to assign the solar rebate payment to the lessor. SACE contends that such a practice would "add unnecessary complexity" for customers and lessors, and is inconsistent with the directive of G.S. 62-126.2 to "encourage the leasing of solar energy facilities for retail customers." Like NCSEA, SACE references Duke's South Carolina solar rebate program, which allows for the assignability to third parties of solar rebate payments. SACE requests that the same be expressly allowed in Duke's proposed Solar Rebate Rider.

SACE further expresses concern that the Solar Rebate Rider terms and conditions grant Duke "significant discretion in accepting and/or approving applications for solar rebates without providing adequate parameters defining that discretion." SACE provides the following as examples: (1) "Participation under the program is available on a 'first-come-first-served' basis for systems installed on or after January 1, 2018, subject to the Company's discretion"; (2) Duke "in its sole and absolute discretion, may accept or reject any rebate application for good cause as determined by the Company"; (3) Duke's proposed imposition of an early termination charge, "unless early termination results from good cause as determined by the Company"; and (4) Duke's reservation of its right to terminate service under the Solar Rebate Rider if a customer "operates the generating system in a manner which is detrimental to the Company and/or its customers." For the purpose of ensuring fair access to and transparency surrounding participation in the Solar Rebate Rider, SACE requests that Duke more clearly delineate the narrow circumstances under which a customer's application may be rejected or service under the Solar Rebate Rider terminated. SACE further requests that Duke more specifically define "good cause," "event of early

[1] See Commission Rule R8-73(i)(2).

termination," and "manner which is detrimental to the Company and/or its customers," as those terms are used in Duke's Solar Rebate Rider leaflets.

In its reply comments, SACE agrees with NCSEA regarding both the concern that bad actors may abuse the system under Duke's proposed method for determining nameplate capacity, as well as the recommendation to instead use a fixed conversion factor for converting DC to AC to calculate more accurately the amount of the solar rebate to which the participant is entitled. SACE further agrees with NCSEA that Duke should be required to provide additional information regarding the application process and the methods by which an application may be submitted to Duke. Finally, SACE supports NCSEA's recommendation that the Commission should reserve the right in the future to re-evaluate, in the context of current market trends, the reasonableness of the incentives offered under the Solar Rebate Rider, particularly when Duke's revised net metering tariffs take effect.

Duke's Reply Comments

In its reply comments, Duke states that its discussions with the Public Staff concerning cost recovery of total Solar Rebate Rider incentives are ongoing, and will continue, to the extent necessary, in the Companies' respective cost recovery proceedings pursuant to G.S. 62-133.8(h). Duke also states that, as a result of its discussions with the Public Staff, the Company agrees to eliminate the proposed one-year renewal terms, at the Company's option, upon the conclusion of the ten-year contract period for service under the Solar Rebate Rider.[1]

In response to NCSEA's suggestion that Duke should be required to include in its proposed annual report an opinion regarding whether rebate values continue to be appropriate in the context of then-current market conditions, Duke states that it is willing to "commit to a stakeholder review process should trends in customer adoption rates warrant [the same]." It disagrees, however, with the suggestion advanced by both NCSEA and SACE that certain changing circumstances in the solar market should automatically necessitate further review or modification by the Commission of the Solar Rebate Rider.

Duke disagrees with SACE's recommendation that customers should be allowed to use the dates of initial application submission and installation, for purposes of determining compliance with the 90-Day Rule, if they are required to reapply the following year due to the annual program cap already having been reached in the year that the initial application was submitted. Duke contends that such a policy would increase both customer confusion and its own administrative burdens. Duke further contends that a customer can avoid this risk entirely by availing themselves of the option to obtain a rebate reservation prior to installing a solar PV system.

Duke agrees with SACE's recommendation that the date of this Order should be considered as the installation date for otherwise eligible solar facilities that are installed after January 1, 2018, but prior to the date of this Order.

[1] The Public Staff in its comments did not express a concern over this provision. Duke in its application did not explain the reason for its inclusion of this provision, nor did it explain in its reply comments why it agreed to strike this provision.

In response to the concerns of NCSEA and SACE, Duke agrees to post monthly updates on its website regarding progress made toward Solar Rebate Rider participation limits, and commits also to publishing on the Companies' websites a notice if and when the annual participation limit for any participant class is reached.

In response to NCSEA and SACE's arguments that rebates issued under Duke's proposed Solar Rebate Rider should be assignable to third parties, Duke contends this would not be in the best interest of customers. In addition, Duke contends that "[b]ased on high-level estimates, allowing a customer to assign the rebate payments to someone other than themselves would double the [information technology (IT)] cost, and would require IT security and legal involvement, as the Companies would be required to collect tax identification numbers and other information from third parties." Duke further contends that such a policy would lengthen the time necessary for the Companies to launch the Solar Rebate Rider.

In response to NCSEA and SACE's concerns regarding Duke's discretion in the administration of the Solar Rebate Rider, Duke states that "[a]llowing discretion in the decision-making is necessary to provide appropriate and fair service to the customer." In addition, Duke states that the Commission already has remedies through the consumer complaint process to address any instances in which someone may believe that Duke improperly asserted its discretion.

In response to NCSEA and SACE's concerns regarding the usage of the inverter's nameplate capacity to determine the rebate amount and the consequent potential for a bad actor to artificially inflate the rebate amount to which a customer is entitled, Duke states that the intervenors are asking it "to provide an anticipatory remedy in the event some participants may cheat." Duke contends that the scenario described by NCSEA is "highly uncommon," and that even if it did occur, it would not pose a risk to the Companies or the grid. Nevertheless, Duke states that it will review for future consideration any fixed conversion factor and supporting methodology provided to it by NCSEA.

With regard to the request that Duke should provide additional details about customer eligibility and the application process, Duke contends that it would not be prudent to do so until such time as the Commission first approves the Solar Rebate Rider. Duke does, however, clarify that it expects to issue solar rebate payments within 30-45 days of the later between the date of project completion and the date of application approval. Duke also clarifies that a business with multiple locations will be able to apply for multiple rebates, provided that each location has a different account number unique to it.

DISCUSSION AND CONCLUSIONS

The Commission has carefully reviewed Duke's filings, the comments of the Public Staff, NCSEA, and SACE, as well as the consumer statement of position. Based upon the foregoing and the entire record in this proceeding, the Commission agrees with the parties that Duke's proposed Solar Rebate Rider generally meets the requirements of G.S. 62-155(f). However, Duke and other parties to this proceeding have brought to the Commission's attention a number of suggestions for improvement to the Solar Rebate Rider. In addition, the Commission itself has concerns about a few terms and conditions of the Solar Rebate Rider that either were not mentioned or fully addressed by the parties. The Commission will proceed to resolve these issues, and, consistent with the conclusions reached herein, will require Duke to modify its Solar Rebate Rider, and to make a compliance filing accordingly within ten days from the date of this Order.

Future Review and Re-Evaluation of the Solar Rebate Rider

NCSEA suggests, and SACE agrees, that Duke should be required as part of its annual report to the Commission to opine whether solar market conditions have changed such that the reasonableness of the incentives offered through the Solar Rebate Rider are affected as a result. Specifically, SACE references the requirement in House Bill 589, codified as G.S. 62-126.4, for the Companies to file for approval by the Commission revised net metering rates. There is no deadline in G.S. 62-126.4 by which the Companies must propose such revisions, but NCSEA and SACE express concern that the same could affect negatively the value and reasonableness of solar rebate payment amounts. While the Companies express a willingness to commit to "a stakeholder review process should trends in customer adoption rates warrant [the same]," the Companies "find it unnecessary" to commit to further review by the Commission.

The Commission finds that Duke, in its reply comments, implicitly agrees with NCSEA and SACE that market changes conceivably could occur between the date of this Order and the conclusion of the Solar Rebate Rider program offering. The disagreement between the parties as to this issue then lies in determining the appropriate remedy in the event that such market changes rise to the level of warranting stakeholder review or Commission action. The Commission concludes that NCSEA and SACE raise a valid concern, and agrees that the reasonableness of the incentives offered through the Solar Rebate Rider could change due to future changes in the solar market. The Commission acknowledges that Duke's net metering rates, under which a Solar Rebate Rider participant must also receive service, will change at some future date uncertain as required by the passage of House Bill 589. However, the extent to which such revisions could affect the value of solar rebate payments remains to be seen. For reasons including the potential scenarios predicted herein, in addition to others that may not be foreseeable at present, the Commission concludes that there exists a compelling reason for it to continue to monitor the reasonableness of the incentives offered throughout the duration of the Solar Rebate Rider. Accordingly, the Commission directs Duke to include information about this issue in its annual report, as requested by NCSEA and SACE. The Commission will evaluate this issue during each proceeding to review the Companies' annual reports. That proceeding also will be the appropriate venue through which intervening parties can raise this or other issues for the Commission's review and decision.

Application Timeline

An applicant for service under the Solar Rebate Rider is required to apply no later than 90 days following the installation of a qualifying solar PV system (90-Day Rule). For customers who already have installed a solar PV system but are required to reapply during the next year as a result of program capacity already having been reached for the calendar year in which the application was first submitted, NCSEA and SACE object to Duke's use of the date of installation relative to the date of the second application submission for purposes of determining compliance with the 90-Day Rule. Instead, NCSEA and SACE suggest that for these customers, the dates of the initial application and project completion should be used. Duke contends that the method advanced by NCSEA and SACE could increase both customer confusion and the Companies' administrative costs. Duke further contends that customers are able to obtain a rebate reservation prior to installation, which would avoid the risk altogether of subsequent rebate ineligibility after the solar PV system already has been installed. The Commission agrees with Duke that its pre-installation reservation system is a sufficient safeguard for those customers whose circumstances are such that they need or want to reserve a rebate guarantee before purchasing or leasing a solar PV system. In order to ensure that prospective participants of the Solar Rebate Rider are informed of the reservation guarantee option, the Commission directs Duke to prominently display the process by which a customer can apply for such reservation on both the Companies' websites and Solar Rebate Rider leaflets.

At NCSEA and SACE's request, Duke agrees to use the date of this Order as the installation date for otherwise eligible solar facilities installed after January 1, 2018, but prior to the date of this Order. The Commission directs Duke to include this clarification in its compliance filing.

In response to Dr. Bansode's consumer statement of position asking the Commission to mandate a retroactive eligibility period for those solar PV systems installed between January 1, 2017, and December 31, 2017, the Commission refers to G.S. 62-155(f), which in part specifies that the incentives offered through the Solar Rebate Rider will be available for capacity installed "starting in January 1, 2018." Any changes to this beginning date as specified in House Bill 589 must come through legislation passed by the North Carolina General Assembly, not by Commission action. Accordingly, the Commission declines to adopt Dr. Bansode's recommendation.

<u>Reporting</u>

Duke proposes filing in this proceeding an annual report on April 1, 2019, and each calendar year thereafter, detailing participation rates by customer class, the number of applications rejected, the number of applications canceled at year-end, and the program costs incurred to date. Both NCSEA and SACE argue that more frequent reporting of the progress toward the annual program cap is needed, and suggest that Duke either report this progress on a monthly or an incremental basis until the cap has been fulfilled each year. In its comments, Duke agrees to publish on its website both monthly progress updates toward annual participation limits and notices when each year's annual limit is reached for any participant class. Duke also commits to file with the Commission a notice when any annual capacity limit is reached. The Commission agrees with the intervenors, and finds Duke's proposal in response sufficient to reasonably address the intervenors' concerns regarding this issue. Accordingly, the Commission directs Duke to publish on its website, in a conspicuous manner that is easy for both customers and installers to locate, the notices and monthly updates as offered in its reply comments. In addition, the Commission directs Duke to file with the Commission a notice when each year's annual limit is reached for any participant class.

As a related matter, the Commission notes that it presently is difficult for visitors to Duke's website to access information for service territories other than the one initially selected upon first visiting Duke's website. The Commission finds that ease of access to information about the different company-specific Solar Rebate Riders is important to help improve chances of maximum program participation. Accordingly, the Commission directs Duke to provide in its compliance filing the Uniform Resource Locators (URLs) at which information about the Solar Rebate Rider can be found for both DEC and DEP's respective service territories. Visitors to either of these URLs should be able to quickly ascertain details surrounding the application process, including the details contained in Duke's application, the details contained in Duke's reply comments not otherwise found in its application, and the information Duke is directed to provide by the Commission herein.

Assignment of Rebate Payment

Both NCSEA and SACE advocate for the assignability to third parties of solar rebate payments, particularly when a customer leases the solar PV system from an installer-lessor. Duke disagrees, and cites in support of its position the need for customer protection, increased IT and legal costs, and an increased time frame between Commission approval and the launch of the Solar Rebate Rider. The Commission agrees with Duke, and notes that G.S. 62-155(f) contemplates that the incentives offered through the Solar Rebate Rider will be provided "to [] customers." From a policy perspective, the Commission finds a compelling reason to ensure that whichever party who would be liable to pay an early termination charge in the event of cancellation of service under the Solar Rebate Rider before the conclusion of the 10-year contract term, also should be the same party who receives the solar rebate payment. Because the terms and conditions as proposed would hold the customer, and not the third-party installer or lessor responsible for paying an early termination charge, the Commission finds that it would be inappropriate at this time to require Duke to allow third-party assignability of solar rebate payments. However, the Commission reserves the right to reevaluate this issue through its annual review of the Solar Rebate Rider, and directs Duke to include in its first annual report information regarding whether the inability to assign solar rebate payments to third parties caused any issues for either customers or installers during the first year of the Solar Rebate Rider.

The Commission also notes that third-party installers and lessors are able to contract and negotiate directly with customers to ensure that installer-lessors receive payment for their services and equipment. The Commission further notes that such third parties may avail themselves of legal remedies for non-payment through the general courts of justice, should the need arise.

Program Discretion

Both NCSEA and SACE contend that a number of Duke's terms and conditions are ambiguous and leave the Companies with excessive discretion in the administration of the Solar Rebate Rider. Duke, on the other hand, contends that a certain level of discretion is necessary to ensure that the Solar Rebate Rider is administered properly, and notes that the Commission already has in place procedures through which a customer may complain about Duke if he or she believes that Duke has improperly applied such discretion.

The Commission finds legitimate the concerns expressed by NCSEA and SACE as to the ambiguity of certain terms and the amount of discretion Duke proposes to retain. Although the Commission acknowledges that a customer may file a complaint if he or she believes that Duke improperly applied its discretion, the Commission concludes that it is important to increase transparency and clarity of program rules and restrictions on the front end in order to reduce the possibility that a customer may need to file a complaint in the future. Accordingly, the Commission directs Duke to remove the language preserving its discretion when there are objective, clear criteria which obviate the need for such discretion. For example, the Commission finds no compelling reason for Duke to retain discretion to reject an application for participation under the Solar Rebate Rider when the customer and solar PV system satisfy the objective application and eligibility requirements, and no otherwise disqualifying event occurs, such as an intentional misstatement or misrepresentation to Duke during the application process. Accordingly, the Commission directs Duke in its compliance filing to modify its leaflets such that the Companies retain discretion only in instances when there do not exist objective, defined criteria, such as determining whether a customer qualifies, a solar PV system is eligible, or application requirements are satisfied. In addition, the Commission directs Duke to clarify that only a material and intentional misstatement or misrepresentation will result in early termination or request for repayment of the solar rebate.

For provisions in which such clear and objective criteria may not be as discrete, such as circumstances that may lead to termination of service, the Commission directs Duke in its compliance filing to clarify ambiguous terms. For example, the Commission notes that the Solar Rebate Rider leaflets do not define what constitutes "good cause," thus exempting a customer from having to pay an early termination charge if his or her electric service is disconnected prior to the conclusion of the Solar Rebate Rider contract term. Therefore, the Commission orders Duke to modify its Solar Rebate Rider terms and conditions, as requested by the intervenors, to clarify and better define such ambiguous terms.

In addition, the Commission directs Duke to add a term to its Solar Rebate Rider leaflets that informs the customer about the complaint process available before the Commission, to include the appropriate contact information for the Public Staff. Finally, to further alleviate this concern of the intervenors, the Commission directs the Companies to include in their respective annual report filings the reasons for any rejected applications and early terminations, in addition to the number of such rejections and early terminations. For early terminations, the Commission directs Duke also to include whether or not the customer was required to pay an early termination charge and, if so, the amount of such charge. The Commission, although not expressly disallowing the imposition of an early termination charge in this Order, hereby informs the parties that it has concerns that this charge could constitute a disincentive to participate in the Solar Rebate Rider. Accordingly, the Commission will monitor this closely during the annual review process, particularly if certain participant classes are undersubscribed in any year.

Calculation of Generating Capacity

NCSEA recommends, and SACE agrees, that the Companies should use a fixed conversion factor to convert the direct current generating capacity to alternating current for purposes of calculating the rebate amount for which the customer is eligible. Although the Companies disagree that this issue poses a large risk for abuse by installers or that it would be detrimental to the Companies or the grid in the unlikely event that it did occur, the Companies state that they are willing to review for future consideration a fixed conversion factor and supporting methodology provided to it by NCSEA. The Commission, therefore, directs Duke to include a statement in its first annual report to be filed in this proceeding on or before April 1, 2019, indicating whether NCSEA did in fact provide to Duke a conversion factor for direct current to alternating current for purposes of calculating the accurate amount of solar rebate to which the applicant is entitled. Duke also is directed in its first annual report to inform the Commission whether it proposes to use any such conversion factor provided to it and, if so, to provide any proposed revisions to the Solar Rebate Rider accordingly. Finally, the Commission expects Duke to identify and correct any potential instances of fraud in the rebate application process, and directs Duke to include a report of any such occurrences in its annual report.

Allocation of Installed Capacity Available and Differing Rebate Amounts

Although not an issue raised by the parties, the Commission notes that the Solar Rebate Rider seeks to limit to 5,000 kW both residential and nonresidential installations eligible for the rebate during any one calendar year. While G.S. 62-155(f) imposes a 5,000 kW maximum limit on nonresidential installations, there is no such limitation on residential installations. Similarly, while there are set-asides reserved in G.S. 62-155(f) for non-profit customers, there is no such set-aside for nonresidential customers in general. Duke's proposal to treat nonresidential participation as a set-aside and to impose a participation limit on residential participation, therefore, appears to be contrary to legislative intent. As a practical matter, the proposed residential cap also seems to be inconsistent with the Companies' own proposal to make the Solar Rebate Rider available on a "first-come-first-served" basis for otherwise eligible customers and solar PV systems, subject to the set-asides reserved by statute. Therefore, the Commission directs the Companies in their compliance filing to remove the proposed 5,000 kW cap on residential installations. Instead, applications should be processed in the order in which they are received by the Companies, subject only to the statutorily-mandated limitations and set-asides.

On a related note, the Commission notes that Duke proposes to include in its annual report the rates of participation by customer class. To be clear, the Commission expects that Duke will provide information regarding the amount of reserved and approved installed capacity for each participant class, including those for which a set-aside capacity is reserved. The Commission also expects Duke to include, in its first annual report filing on or before April 1, 2019, an explanation for why it elected to offer differing solar rebate payments amounts to each participant class.

Contract Term

Although not raised by the parties, the Commission has concerns that the 10-year contract term under the Solar Rebate Rider, particularly when combined with the penalty for early termination, could be a disincentive to participation. The Commission contrasts, for example, the proposal under the Solar Rebate Rider to the one-year contract term of DEC's current net metering rider, which provides for an early termination charge limited only to actual costs to the Company of such early cancellation. While the Commission acknowledges Duke's offer, after discussions with the Public Staff, to strike the optional one-year renewal periods following the conclusion of the initial 10-year contract term, the Commission puts the parties on notice that it may reevaluate this issue in the future. The Commission will monitor closely whether additional changes to the contract term are needed, particularly if any participation class is undersubscribed in any year. In the meantime, the Commission expects Duke to ensure that its imposition of any early termination charge under the Solar Rebate Rider is consistent with its North Carolina Service Regulations.

On a related note, the Commission directs Duke in its compliance filing to strike the one-year optional renewal provisions from the Solar Rebate Rider terms.

Conclusion

The Commission notes that the Solar Rebate Rider leaflets proposed by the Companies contain a number of typographical and grammatical errors, including the incorrect titling of DEC's proposed Solar Rebate Rider SRR application. The Commission directs the Companies to proofread the leaflets and corresponding application forms, and to correct these errors in their compliance filing.

Based upon the foregoing and the entire record in this proceeding, the Commission concludes that Duke's application for approval of its solar rebate program, made available through DEC's Solar Rebate Rider SRR and DEP's Solar Rebate Rider SRP, should be modified consistent with this Order. Once modified, the Commission finds that the Solar Rebate Rider is reasonably designed to achieve the mandates and objectives of G.S. 62-155(f). Therefore, the Commission finds that Duke's application should be approved, as modified, and orders Duke to submit a compliance filing within ten (10) days of the date of this Order.

IT IS, THEREFORE, ORDERED as follows:

1. That Duke's application for approval of its solar rebate program, made available through DEC's Solar Rebate Rider SRR and DEP's Solar Rebate Program Rider SRP is granted, subject to the modifications required by the Commission in this Order;

2. That Duke, within ten days from the date of this Order, shall make a compliance filing to include redlined revisions to its leaflets and corresponding application forms in conformance with this Order;

3. That Duke shall submit an annual report on or before April 1, 2019, and every calendar year thereafter, which shall include: (1) all information offered by the Companies to be included in the report; (2) all additional information directed by the Commission in this Order; and (3) any proposed changes to the Solar Rebate Rider; and

4. That Duke shall file with the Commission and publish conspicuously on its website a notice whenever an annual participation limit under the Solar Rebate Rider is reached. Duke also shall publish conspicuously on its website monthly updates of progress made toward such annual participation limits.

ISSUED BY ORDER OF THE COMMISSION.
This the 3rd day of April, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

Commissioner Charlotte A. Mitchell did not participate in this decision.

DOCKET NO. E-2, SUB 1169
DOCKET NO. E-7, SUB 1168

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition of Duke Energy Progress, LLC,	)	ORDER ESTABLISHING
and Duke Energy Carolinas, LLC,	)	PROCEEDING TO REVIEW
Requesting Approval of Community Solar	)	PROPOSED COMMUNITY
Program Plan Pursuant to G.S. 62-126.8	)	SOLAR PROGRAM PLAN

BY THE CHAIRMAN: On December 19, 2017, in Docket No. E-100, Sub 155, the Commission issued an Order adopting Commission Rule R8-72. Commission Rule R8-72 provides for the implementation of G.S. 62-126.8, including the requirement that the Commission oversee and approve each community solar energy facility program plan.

On January 23, 2018, in Docket Nos. E-2, Sub 1169, and E-7, Sub 1168, Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC (collectively Duke), jointly filed a proposed community solar program plan, consistent with the requirements of Section 6.(d) of House Bill 589 (S.L. 2017-192).

The Chairman, therefore, finds good cause to initiate this proceeding to review Duke's proposed community solar program plan. The Chairman invites interested persons to petition to intervene and to provide comments or suggestions to assist the Commission in its review of Duke's proposed community solar program plan.

IT IS, THEREFORE, ORDERED as follows:

1. That the participation of the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e);

2. That other interested persons wishing to become formal parties and participate in this proceeding may file petitions to intervene pursuant to Commission Rules R1-5 and R1-19 on or before March 23, 2018;

3. That the Public Staff and intervenors may file initial comments or suggestions, as provided herein, on or before March 23, 2018;

4. That all parties may file reply comments or suggestions, as provided herein, on or before April 13, 2018;

5. That, upon receipt of the parties' initial and reply comments, the Commission will proceed appropriately in deciding whether to approve Duke's proposed community solar program plan; and

6. That the Chief Clerk shall transmit a copy of this Order to all parties of record in Docket No. E-100, Sub 155.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of January, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

DOCKET NO. E-2, SUB 1172
DOCKET NO. E-7, SUB 1171

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Duke Energy Carolinas, LLC and Duke	)	ORDER ACCEPTING FILING OF
Energy Progress, LLC Advance Notice of	)	AFFILIATE AGREEMENT AND
Affiliate Agreement between Duke Energy	)	GRANTING LIMITED WAIVER
Carolinas, LLC and Duke Energy Progress, LLC	)	OF REGULATORY CONDITION

BY THE COMMISSION: On March 20, 2018, Duke Energy Carolinas, LLC (DEC) and Duke Energy Progress, LLC (DEP, collectively Duke) filed a Joint Advance Notice and Request for Acceptance of Affiliate Agreement under N.C. Gen. Stat. § 62-153 and for Limited Waiver of Regulatory Condition No. 3.1(b) (Advance Notice) in the above- captioned dockets. The Advance Notice was filed pursuant to G.S. 62-153 and Regulatory Condition Nos. 3.1(c) and 13.2. Regulatory Condition Nos. 3.1(c) and 13.2 are among those approved in the Commission's Order Approving Merger Subject to Regulatory Conditions and Code of Conduct in Docket Nos. E-2, Sub 1095, E-7, Sub 1100, and G-9, Sub 682, issued on September 29, 2016. In the Advance Notice, Duke describes an Agreement for Regional Equipment Sharing for Transmission Outage Restoration (RESTORE Agreement), and requests that the Commission (1) accept the RESTORE Agreement for information and filing under G.S. 62-153(a), (2) approve a limited waiver of Regulatory Condition No. 3.1(b), and (3) accept Duke's notice of intent to sign onto the RESTORE Agreement under Regulatory Condition Nos. 3.1(c) and 13.2.

Summary of the RESTORE Agreement

Duke explains that on December 13, 2017, the participants in the RESTORE Agreement (RESTORE Participants) filed a Joint Application for Prior Authorization for the Disposition and Acquisition of Jurisdictional Transmission Facilities of the Jurisdictional RESTORE Participants (Joint Application) at the Federal Energy Regulatory Commission (FERC) for pre-authorization under Sections 203(a)(1)(A) and 203(a)(1)(B) of the Federal Power Act for transactions that may occur under the RESTORE Agreement. The RESTORE Participants include affiliates of DEC and DEP, and the Joint Application indicates that DEC and DEP intend to execute the RESTORE Agreement as soon as applicable state utility commission requirements are satisfied. The Joint

Application was attached to Duke's Advance Notice as Attachment 1, and the RESTORE Agreement was attached as Exhibit A to the Joint Application.

Duke states that the RESTORE Agreement establishes a framework for the efficient and timely transfers of transmission-related equipment among the RESTORE Participants following a catastrophic emergency or natural disaster. According to Duke, the RESTORE Participants have agreed to form a group to share certain classes of spare transformers, along with less costly components such as circuit breakers (collectively, Qualifying Equipment). The sharing will occur under agreed-upon financial provisions during a Triggering Event, which is defined in Section I of the RESTORE AGREEMENT as a "catastrophic event creating an urgent grid need in which, for an extended period of time, a Participant loses its ability to serve significant load, is at imminent risk for losing significant load, or cannot maintain grid stability." Duke further states that the potential disruption to infrastructure and normal market conditions caused by a Triggering Event could be mitigated or avoided through the cooperative RESTORE Agreement, and that DEC and DEP desire to execute and participate in the RESTORE Agreement in order to extend its benefits to their customers. In addition, Duke explains that other affiliates of DEC and DEP are already RESTORE Participants, and, therefore, the RESTORE Agreement makes a future transfer between DEC or DEP and one or more of their other affiliates during a Triggering Event a possibility.

Duke explains that the purchase price of Qualifying Equipment is the replacement cost,, including transportation and other acquisition costs, plus any reasonable costs and expenses of the seller, including shipping costs if the seller decides to offer transportation services, and tax liability attributable to the sale. Duke states that its participation in the RESTORE Agreement can be done with existing assets and will not require the purchase of additional transformer stock beyond that which is otherwise maintained on hand for service to DEC's and DEP's native load customers. Further, if a spare transformer or component is sold by DEC or DEP after a Triggering Event, they anticipate that they will be able to obtain a replacement transformer or component from the market within a reasonable time period. In addition, Duke states that its participation in the RESTORE Agreement will not affect existing arrangements or regulatory commitments for transferring assets among DEC's and DEP's current affiliated entities. Finally, Duke states that DEC and DEP will not pay fees or compensation for services rendered by or to be rendered to any of the RESTORE Participants, and that if DEC, DEP or any of their operating company affiliates who are Participants make payments to one another the payments will be for the transfer of the Qualifying Equipment.

Request for Limited Waiver of Regulatory Condition

With regard to Duke's request for a limited waiver of Regulatory Condition (RC) No. 3.1(b), Duke notes that this RC requires that all affiliate contracts to which DEC or DEP are a party shall contain specified provisions, including the provision required by RC No. 3.1(b)(i):

> DEC's, DEP's, or Piedmont's participation in the agreement is voluntary, DEC, DEP, or Piedmont is not obligated to take or provide services or make any purchases or sales pursuant the agreement, and DEC, DEP, or Piedmont may elect to discontinue its participation in the agreement at its election after giving any required notice.

Duke states that if DEC or DEP agree to be RESTORE Participants but then indicate that they are not bound by the process of equipment sharing, the other RESTORE Participants might view DEC's and DEP's participation as an illusory commitment, and, therefore, might object to DEC's and DEP's participation. Further, Duke notes instances in which the Commission has previously allowed Duke to modify the language required by RC No. 3.1(b). As a result, Duke requests to modify RC No. 3(b)(i) by adding the underlined addition below:

> DEC's or DEP's participation in the agreement is voluntary, DEC or DEP is not obligated to take or provide services or make any purchases or sales pursuant to the agreement <u>except as expressly provided</u>, and DEC or DEP may elect to discontinue its participation in the agreement at its election after giving any required notice.

<u>Public Staff's Response</u>

On April 3, 2018, the Public Staff filed a Response to Duke's Advance Notice. The Public Staff states that Duke provided a draft of the RESTORE Agreement to the Public Staff for its review prior to filing the Advance Notice. With regard to RC Nos. 3.1(c) and 13.2, the Public Staff notes that these RCs include procedures for Duke to provide advance notice regarding affiliate contracts when such contracts are required or intended to be filed at FERC. The Public Staff states that in this instance the RESTORE Agreement has already been filed at FERC and the Joint Application remains pending, but that Duke intends to join the RESTORE Agreement at the end of the advance notice period, as defined by RC No. 13.2. Moreover, the Public Staff states that it does not believe that the RESTORE Agreement, if accepted by the FERC as filed, will adversely affect the Commission's jurisdiction. In addition, the Public Staff states that it has no objection to the Commission granting a limited waiver of RC No. 3.1(b), and to DEC and DEP signing the RESTORE Agreement. Further, the Public Staff recommends that the Commission accept the RESTORE Agreement for filing under G.S. 62-153(a) without prejudice to the right of any interested party to take issue with any provision of the RESTORE Agreement in a future proceeding.

Discussion and Conclusion

G.S. 62-153(a) requires public utilities to file with the Commission copies of certain contracts with affiliated companies. Affiliate agreements filed under G.S. 62-153(a) are filed for informational purposes and not for approval, although the contract remains subject to disapproval. In addition, G.S. 62-153(b) requires public utilities to file for Commission approval proposed affiliate agreements where the public utility will pay fees or compensation for services rendered or to be rendered. The scope of the Commission's review under G.S. 62-153 is to determine whether the contract is (1) just and reasonable, and (2) not made for the purpose of concealing, transferring or dissipating earnings of the public utility.

Based on the foregoing and the record, the Commission finds and concludes that DEC's and DEP's participation in the RESTORE Agreement is reasonably likely to benefit their customers if a Triggering Event impacts their service territories. Further, the Commission finds and concludes that DEC's and DEP's execution of and participation in the RESTORE Agreement is just, reasonable, and in the public interest, subject to the condition that any party may take issue with a provision of the RESTORE Agreement or payment made thereunder in a future proceeding. Finally, the Commission concludes that there is good cause to grant Duke a limited waiver of the requirements of Regulatory Condition No. 3.1(b).

IT IS, THEREFORE, ORDERED as follows:

1. That the RESTORE Agreement shall be, and is hereby, accepted for filing under G.S. 62-153(a).

2. That the Commission's acceptance of the RESTORE Agreement for filing is without prejudice to the right of any party to take issue with any provision of or payment under the RESTORE Agreement in an appropriate proceeding.

3. That Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC shall be, and are hereby, granted a limited waiver of the requirements of Regulatory Condition No. 3.1(b)(i) with regard to the RESTORE Agreement, and may include their proposed revised Regulatory Condition No. 3.1(b)(i) in the RESTORE Agreement.

4. That the request of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, to sign the RESTORE Agreement shall be, and is hereby, approved.

ISSUED BY ORDER OF THE COMMISSION.
This the 18th day of April, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. E-22, SUB 532

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	)))))	ORDER APPROVING LED RATE SCHEDULE

BY THE COMMISSION: On December 22, 2016, the Commission issued an Order Approving Rate Increase and Cost Deferrals and Revising PJM Regulatory Conditions (Rate Order) in the above-captioned docket. The Rate Order, among other things, required Dominion Energy North Carolina (DENC) to file a proposed new light emitting diode (LED) schedule for North Carolina jurisdictional customers.

On February 1, 2018, DENC filed its proposed LED offering. DENC's LED offering is included in revised Schedule 26, Outdoor Lighting Service. In summary, DENC stated that the rates contained in revised Schedule 26 were developed based on DENC's goals of simplifying rates for outdoor lighting, serving its customers' interests in cost and energy savings, and incentivizing the conversion of outdoor lighting to LED technology. DENC explained that it proposed the LED offering as part of its existing Schedule 26, rather than a stand-alone schedule, as the most efficient way to offer outdoor lighting customers the opportunity to install new LED technology or convert existing older, less efficient lighting options to LED. According to DENC, revised Schedule 26 incorporated monthly rates for LED lighting fixtures, corresponding to 10 tiers of lumens ranging from 2,000 to 27,000. DENC further noted that the monthly rates contained in revised Schedule 26 were based on recently updated labor cost data and assumed a lower LED fixture cost compared to current market costs for LED fixtures, thereby reflecting the most current and cost-effective projections associated with LED technology. In addition, DENC stated that the proposed LED tariff included a conversion charge that would be applicable to existing mercury vapor (MV) and high pressure sodium (HPS) fixtures that are replaced with LED fixtures at the customer's request. The proposed conversion charge would be $117.40 for luminaries associated with basic fixtures, and $535.79 for luminaries associated with premium fixtures.

On February 15, 2018, the Commission issued an Order Requesting Comments and Reply Comments on DENC's proposed LED offering.

On March 5, 2018, the Public Staff filed comments. In summary, the Public Staff stated that it had reviewed DENC's proposed changes to Schedule 26, including the proposed structure and rates for LED, and concluded that the proposed rates were appropriately calculated using DENC's cost inputs from the Rate Order proceeding, as well as updated labor cost data. The Public Staff noted, however, that DENC did not include an update of federal taxes to reflect the tax changes that became effective on January 1, 2018, pursuant to the Federal Tax Cuts and Jobs Act of 2017. The Public Staff stated that in response to a Public Staff data request, DENC provided the Public Staff with recalculated rates on February 23, 2018, that incorporated the new federal tax rate.

With regard to the conversion charges proposed by DENC, the Public Staff stated that DENC's calculations were based on recovering its entire net book value of lighting assets over a 15-year conversion period, and that in discussions with the Public Staff DENC stated that it chose this approach because it did not have information regarding the amount of time certain fixtures had been in service. The Public Staff noted that DENC has effectively consolidated and socialized its entire lighting inventory, making it difficult to determine the length of time that a fixture has been in service. The Public Staff stated that this approach has the effect of depreciating a portion of the DENC's lighting inventory a second time, and could create a substantial barrier to the transition to LED lighting. However, even though DENC does not know how long a particular fixture has been in service, the Public Staff opined that DENC should know how long the customer has been paying for lighting service, and that with this knowledge DENC should be able to determine a reasonable proxy for the length of time that a fixture has been in service. The Public Staff obtained from DENC data on DENC's inventory of MV and HPS lighting fixtures, and reviewed the Form E-1, Item 42 revenue analysis filed with DENC's November 16, 2009 rate case in Docket No. E-22, Sub 459. The Public Staff noted that the production of MV ballasts has been prohibited by the Energy Policy Act of 2005 since 2008, thereby effectively rendering MV fixtures obsolete. Based on these facts, the Public Staff concluded that any fixture that has been in service for at least 20 years should be exempt from a conversion charge. It stated that this threshold for distinguishing the application of a conversion charge is based on similar fees and structures used by Duke Energy Progress, LLC (DEP) and Duke Energy Carolinas, LLC (DEC).

The Public Staff also noted that DENC's conversion rate calculations used a 27 year fixture depreciation rate. The Public Staff explained that assuming that 50% of DENC's net book value of lighting inventory (as represented in Appendix D to DENC's application) is fully depreciated, and using DENC's algorithm, the Public Staff recalculated the conversion fees to be $58.70 and $267.89 for basic and premium fixtures, respectively. The Public Staff stated that these amounts are more in line with the conversion fees charged by DEP and DEC.

According to the Public Staff, a conversion charge is necessary to avoid the potential for stranded lighting costs that would be recovered from other lighting customers, and to avoid an onslaught of requests by customers to convert to LED lighting. However, the Public Staff also states that Commission Rule R8-47 encourages utilities to provide customers with more efficient lighting technologies such as LED, and that a conversion charge approximately one-half of that proposed by DENC strikes the appropriate balance for achieving these objectives.

The Public Staff stated that it also reviewed the proposed tariff language included in Appendix A of the Company's application and noted that under Section I DENC offered to replace failed MV fixtures with HPS fixtures at no additional charge to the customer. The Public Staff recommended that the tariff language be changed to also give the customer the option of converting to LED when an MV or HPS fixture fails. The Public Staff acknowledged that this could present aesthetic issues for customers, particularly if the conversion results in a mix of LED, MV, or HPS in a small geographical area. However, the Public Staff opined that the customer should have the opportunity to convert to LED.

In addition, under Section III regarding conversion charges, the Public Staff recommended that language be added to affirmatively state that conversion charges are not applicable to any conversion of MV or HPS to LED upon failure of the MV or HPS fixture.

The Public Staff recommended that the Commission approve DENC's revised Schedule 26 after incorporating the Public Staff's above recommended changes.

On April 20, 2018, DENC filed reply comments. In summary, DENC stated that it had participated in several phone calls and email discussions with the Public Staff, and had provided additional information to the Public Staff to further explain its LED lighting proposal. DENC made the following comments in response to the Public Staff's recommended changes.

New Federal Tax Rate

DENC stated that it agrees that the LED rates provided in Schedule 26 should be updated to reflect the new federal tax rate that took effect on January 1, 2018. As the Public Staff noted in its comments, DENC provided recalculated rates through discovery in February 2018 that incorporated into the Schedule 26 LED rates the new federal tax rate. DENC further stated that this adjustment advantages the proposed LED rates over the rates for other types of fixtures, but that it does not object to this temporary result, mainly because in Docket No. M-100, Sub 148 DENC committed to filing a single-issue adjustment to its base rate cost of service on or before June 30, 2019, if the Company has not filed a general rate case as of that date. DENC stated that the recalculated rates are included in its proposed revised Schedule 26, which was appended to its reply comments as Attachment A, with its workpapers supporting the calculations appended as Attachment B.

Modification to Conversion Fee Structure

DENC stated that it agrees that LED conversion charges are appropriate for the reasons articulated by the Public Staff, and to effectuate the transition encouraged by Rule R8-47. It noted that the Public Staff described DENC's proposal as applying a conversion charge to all customer-requested replacements, regardless of the age of the fixture or the length of time the customer has received service under Schedule 26, and that based on the LED lighting structure and fees of DEP and DEC, the Public Staff contends that any fixture that has been in service for at least 20 years should be exempt from a conversion charge. DENC stated that it does not track MV and HPS fixtures separately, but, instead, employs mass item accounting. As a result, it calculated a single conversion fee, regardless of fixture type, for purposes of its initially proposed conversion fees. However, in response to the Public Staff's position on this issue DENC amended its calculation of the conversion charge to reflect the fact that MV fixtures are becoming obsolete, and based on this new calculation it proposed a conversion charge of $0.00 for MV fixtures (a total of 10,308 in North Carolina as of 12/31/2016), $131.00 for basic HPS fixtures (a total of 16,789 in North Carolina as of 12/31/2016), and $364.00 for premium fixtures (a total of 860 in North Carolina as of 12/31/2016). These changes are reflected in Attachment A to DENC's reply comments. DENC noted that the conversion period for its proposed charges is 16 years, as compared to DEC's most recent proposed conversion period of 44 years, and that this significant difference in conversion timeframe accounts for DENC's higher conversion charges as compared to DEC's charges.

No Conversion Fee for Older Technology Fixtures that Fail

DENC agrees with the Public Staff that Section I of Schedule 26 should be revised to contemplate the conversion to LED fixtures upon the failure of a MV or HPS fixture, and it reflected that change in Attachment A to its reply comments. However, DENC stated that the proposed revisions do not provide the customer a choice of whether or not to replace a failing older technology fixture with LED. According to DENC, allowing customer discretion in this regard would present difficulties for DENC in tracking which localities chose to convert and which localities chose to maintain older technology. Therefore, DENC proposed to revise Section I to provide that, after a six-month transition period, upon failure of any MV or HPS fixture the fixture will be replaced with an LED fixture. DENC submits that this approach is consistent with its goal of furthering the overall conversion to LED fixtures across its system. Further, DENC stated that because it also agrees with the Public Staff that Section III should be revised to clarify that conversion charges will not apply to conversions to LED fixtures that are precipitated by failures of MV or HPS fixtures, this approach will not result in any additional charges to these customers.

Correction to Rate of Return Calculation

DENC stated that the rate of return reflected in the LED rates proposed in its initial filing was calculated using an after-tax return on equity. Subsequent to making the filing, DENC discovered that the carrying charge used in its computation of the rates should have been calculated using a pre-tax rate of return on equity. DENC stated that it corrected this issue, resulting in an increased carrying charge and, thus, increased LED lighting rates, as reflected in Attachment A to its reply comments. DENC noted that the revised carrying charge was calculated using the new federal tax rate.

DENC further stated that in light of the overall price increase resulting from the increased carrying charge, it re-evaluated its allocation of non-fixture plant costs to the various lighting tiers. Based on that reevaluation, it developed a more detailed allocation methodology to account for large wattage fixtures having, on average, higher non-fixture plant costs associated with them. DENC stated that its initial formulation of the LED rates set the cost of non-fixture plant as equal for each of the 10 tiers of basic (and also equal, but higher than basic, for each of the 10 tiers of premium). This method socialized the cost of all non-fixture plant equally among the tiers. Under this methodology, the proposed LED rates had savings versus comparable rates at all levels, though the most significant savings were at the highest tiers. According to DENC, due to the price increase from the carrying charge correction, the corrected LED rates increased at the lower tiers, relative to existing rates, but continued to show savings at the higher tiers. DENC stated that its revised method for allocating non-fixture plant more fairly and evenly distributes rates among the tiers by allocating an average non-fixture plant cost to each tier of basic and premium lighting, based on average pole cost for each wattage of HPS light. DENC further stated that this methodology will help offset some of the rate increase at the lower LED tiers, maintaining some savings for those tiers when compared to existing MV and HPS rates, and is, therefore, consistent with the goal of offering efficient and economical lighting options to customers, as encouraged by Commission Rule R8-47.

In conclusion, DENC requested that the Commission accept and approve its revised Schedule 26 LED lighting offering.

No other party filed comments or reply comments.

Based on the foregoing and the record, the Commission finds and concludes that the LED rates proposed by DENC in its revised Schedule 26, as attached to its reply comments, are just and reasonable. The Commission further concludes that the revised LED rates are consistent with the goal of developing new and more efficient lighting systems. As a result, the Commission finds and concludes that DENC's revised Schedule 26 serves the public interest and should be approved.

IT IS, THEREFORE, ORDERED that DENC's revised Schedule 26 shall be, and is hereby, approved for service rendered on and after June 1, 2018.

ISSUED BY ORDER OF THE COMMISSION.
This the 23rd day of May, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

Commissioner Charlotte A. Mitchell did not participate in this decision.

DOCKET NO. E-7, SUB 1026

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Carolinas,	)	
LLC, for Adjustment of Rates and Charges	)	ORDER APPROVING RIDERS
Applicable to Electric Utility Service in	)	
North Carolina	)	

BY THE COMMISSION: On April 27, 2018, Duke Energy Carolinas, LLC (DEC or the Company), filed a proposed Bulk Power Marketing (BPM) True-up Rider (True-up Rider) and a BPM Prospective Rider (Prospective Rider), to be effective for the period July 1, 2018, through June 30, 2019. The purpose of the BPM Prospective Rider and the BPM True-up Rider is to flow back to DEC's North Carolina retail customers their jurisdictionally allocated share of 90% of the Company's BPM Net Revenues and 100% of its Non-Firm Point-to-Point Transmission (NFPTP) Revenues, on a prospective basis and subsequently a trued-up basis. As reflected in the April 27 filing, the proposed True-up Rider consists of a rate increment of 0.0068 cents per kWh,[1] based on a comparison of DEC's actual BPM Net Revenues and NFPTP Revenues earned in calendar year 2017 with the amounts credited to North Carolina retail customers during 2017 for those categories of Net Revenues and NFPTP Revenues. In the filing, DEC also proposed a Prospective Rider consisting of a rate decrement of (0.0078) cents per kWh[2] to replace the current Prospective Rider of (0.0079) cents per kWh[3] included in base rates.

On June 13, 2018, DEC filed a revised BPM true-up rider schedules to remove certain non-BPM employee expenses that are ineligible for recovery through the BPM True-up Rider. The revised increment True-up Rider of 0.0067 cents per kWh,[4] if approved, will replace the existing increment True-up Rider of 0.0237 cents per kWh[5] approved by the Commission in its Order issued June 20, 2017, in Docket No. E-7, Sub 1026. The sum of the proposed Prospective Rider and True-up Rider, including the regulatory fee, is a rate decrement of 0.0011 cents per kWh, which is a decrease of 0.0169 cents per kWh from the existing combined rider increment of 0.0158 cents per kWh, including the regulatory fee, approved in 2017.

A BPM/NFPTP Rider was first proposed in the Agreement and Stipulation of Partial Settlement (Stipulation) entered into by the Company and various parties in DEC's general rate case in Docket No. E-7, Sub 828. The Commission approved the Stipulation by Order issued on December 20, 2007, and continued to approve the BPM/NFPTP mechanism in subsequent general rate cases. Section 5 of the Stipulation provided that 90% of the allocated North Carolina retail portion of DEC's BPM Net Revenues and 100% of the similarly allocated NFPTP Revenues should be flowed through to the benefit of the Company's North Carolina retail customers. The Stipulation further provided that an annual rider would be established to true up the difference between the actual amounts calculated to be flowed through pursuant to those allocations and percentages and the amounts included in base rates for that purpose, as calculated for the then most recent calendar year.

In its 2013 general rate case order in Docket No. E-7, Sub 1026 (Sub 1026 Order), the Commission reaffirmed the 90% and 100% allocations, and also reaffirmed that the true-up process would continue. Additionally, the Sub 1026 Order directed that (1) in order to facilitate the gradual reduction of the current differential between the amount flowed back in base rates and the actual level of BPM and NFPTP Revenues, beginning with the effective date of the Sub 1026 Order, and continuing until the differential is eliminated, the decrement amounts recovered in base rates would be prospectively implemented in the form of a continuing decrement rider (BPM Prospective Rider), which would be subject to modification in each annual rider

[1] Excluding the North Carolina regulatory fee [0.0068 cents per kWh, including the regulatory fee].

[2] Excluding the regulatory fee [(0.0078) cents per kWh, including the regulatory fee].

[3] Excluding the regulatory fee [(0.0079) cents per kWh, including the regulatory fee].

[4] Excluding the regulatory fee [0.0067 cents per kWh, including the regulatory fee].

[5] Excluding the regulatory fee [0.0237 cents per kWh, including the regulatory fee].

adjustment proceeding; and (2) the return on any over- or under-recovery included as part of the BPM True-up Rider would be calculated using a rate of return equal to 50% of the after-tax rate of return then approved by the Commission. In the BPM Rider filing made in 2014, DEC proposed to reduce the differential over the next four years. The 2017 filing represented the fourth and final year of that process. For years 2018 and forward, the Prospective Rider is calculated annually based on the projected BPM and NFPTP transmission revenues and expected kWh sales. The Public Staff finds this approach reasonable for purposes of this proceeding.

According to DEC's June 13, 2018, revised filing, the proposed True-up Rider is calculated by dividing the North Carolina retail BPM and NFPTP Revenues Adjustment of $3,893,291 (the difference between 2017 actual BPM and NFPTP revenues and the collected 2017 Prospective Rider decrements) by projected North Carolina retail sales of 57,789,224,469 kWh for the period July 2018 - June 2019. The resulting True-up Rider amount is a rate increment of 0.0067 cents per kWh (excluding the regulatory fee).

This matter was presented at the Commission's Regular Staff Conference on June 25, 2018. The Public Staff stated that it had reviewed DEC's calculation of the proposed riders, including the supporting workpapers submitted with the filings and information provided by the Company in response to Public Staff data requests, and had concluded that the proposed revised riders are reasonable. Therefore, the Public Staff recommended that DEC's proposed revised riders be approved.

Based on its review of DEC's filing and the recommendation of the Public Staff, the Commission concludes that the proposed revised riders are reasonable and should be approved, effective on July 1, 2018.

IT IS, THEREFORE, ORDERED that the following riders for Bulk Power Marketing Net Revenues and Non-Firm Point-to-Point Transmission Revenues proposed by DEC in its filing of April 27, 2018, are approved effective during the period July 1, 2018, through June 30, 2019:

(1) a revised BPM True-up Rider, consisting of a rate increment of 0.0067 cents per kWh, excluding the regulatory fee [0.0067 cents per kWh, including the regulatory fee]; and

(2) a BPM Prospective Rider, consisting of a rate decrement of (0.0078) cents per kWh, excluding the regulatory fee [(0.0078) cents per kWh, including the regulatory fee].

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of June, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

Commissioner Charlotte A. Mitchell did not participate in this decision.

ELECTRIC – RATE INCREASE

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

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

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

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

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

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

ELECTRIC – RATE INCREASE

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

APPEARANCES:

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For the Using and Consuming Public:

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BY THE COMMISSION: On July 25, 2017, pursuant to Commission Rule R1-17(a), Duke Energy Carolinas, LLC (DEC or the Company), filed notice of its intent to file a general rate case application. On August 25, 2017, the Company filed its Application to Adjust Retail Rates and Request for an Accounting Order (the Application), along with a Rate Case Information Report, Commission Form E-1 (Form E-1), and the direct testimony and exhibits of David B. Fountain, North Carolina President, DEC; Jane L. McManeus, Director of Rates & Regulatory Planning, DEC; Scott L. Batson, Senior Vice President of Nuclear Operations, Duke Energy Corporation (Duke Energy);[1] Stephen G. De May, Senior Vice President Tax and Treasurer, Duke Energy Business Services, LLC (DEBS);[2] James H. Cowling, Director of Outdoor Lighting for DEC, DEBS; Nils J. Diaz, Managing Director, the ND2 Group, LLC; David L. Doss Jr., Director of Electric Utilities and Infrastructure Accounting, DEBS; Christopher M. Fallon, Vice President, Duke Energy Renewables and Commercial Portfolio (and former Vice President Nuclear Development), Duke Energy; Janice Hager, President, Janice Hager Consulting; Robert B. Hevert, Partner, ScottMadden, Inc.; Retha Hunsicker, Vice President Customer Operations, Customer

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

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

Information Systems, DEBS; Jon F. Kerin, Vice President Governance and Operations Support, Coal Combustion Products, DEBS; Julius A. Wright, Managing Partner, J.A. Wright & Associates, LLC; Kimberly D. McGee, Rates & Regulatory Strategy Manager, DEC and Duke Energy Progress, LLC (DEP); Joseph A. Miller Jr., Vice President of Central Services, DEBS; Robert M. Simpson III, Director Grid Improvement Plan Integration for Duke Energy's Regulated Utilities Operations, DEP; Donald L. Schneider, Jr., General Manager, Advanced Metering Infrastructure (AMI) Program Management, DEBS; and Michael J. Pirro, Manager of Southeast Pricing & Regulatory Solutions, DEC, DEP, and Duke Energy Florida, LLC.

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

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

On September 19, 2017, the Commission issued its Order Establishing General Rate Case and Suspending Rates. On October 13, 2017, the Commission issued its Order Scheduling Investigation and Hearings, Establishing Intervention and Testimony Due Dates and Discovery Guidelines, and Requiring Public Notice, and on October 20, 2017, the Commission issued an Amended Order Scheduling Investigation and Hearings, Establishing Intervention and Testimony Due Dates and Discovery Guidelines, and Requiring Public Notice. On November 3, 2017, Sierra Club filed a Motion to Schedule Additional Public Hearing. On December 22, 2017, the Commission entered an Order Denying Sierra Club's Request for Public Hearing. On January 30, 2018, and February 23, 2018, the Commission issued orders revising the schedule for the expert witness hearing.

On July 10, 2017, the Commission issued an order consolidating DEC's request for deferral of coal ash costs in Docket No. E-7, Sub 1110 with this rate case. On October 18, 2017, the Commission issued an order consolidating the general rate proceeding in Docket No. E-7, Sub 1146 with DEC's request to implement a job retention rider in Docket No. E-7, Sub 1152 and

DEC's petition for approval to cancel the William States Lee III Nuclear Station (Lee Nuclear Project or Lee Nuclear) in Docket No. E-7, Sub 819.

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

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

On January 23, 2017, CUCA filed the direct testimony and exhibits of Kevin W. O'Donnell, President, Nova Energy Consultants, Inc.; the Tech Customers filed the direct testimony and exhibits of Kurt G. Strunk, Director of National Economic Research Associates (NERA), and Edward D. Kee, Expert Affiliate, NERA Economic Consulting; Kroger filed the direct testimony and exhibits of Kevin C. Higgins, Principal, Energy Strategies, LLC; NC Justice Center, et al. filed the direct testimony and exhibits of Satana Deberry, Executive Director, North Carolina Housing Coalition, John Howat, Senior Policy Analyst, National Consumer Law Center, and Jonathan F. Wallach, Vice President, Resource Insight, Inc.; Sierra Club filed the direct testimony and exhibits of Ezra D. Hausman, Ph.D., Consultant, Ezra Hausman Consulting, and Mark Quarles, Principal Scientist and Owner, Global Environmental, LLC; NCLM filed the direct testimony and exhibits of Brian W. Coughlan, President, Utility Management Services, Inc., F. Hardin Watkins, Jr., City Manager, City of Burlington, Maria S. Hunnicutt, General Manager, Broad River Water Authority, and Adam Fischer, Transportation Director, City of Greensboro; CIGFUR III filed the direct testimony and exhibits of Nicholas Phillips, Jr., Managing Principal, Brubaker & Associates, Inc.; and NCSEA filed the direct testimony and exhibits of Justin R. Barnes, Director of Research, EQ Research LLC, Caroline Golin, Southeast Regulatory Director, Vote Solar, and Michael E. Murray, President, Mission:data Coalition. On January 24, 2018, the Commercial Group filed the direct testimony and exhibits of Steve W. Chriss, Director, Energy Strategy and Analysis, Wal-Mart Stores, Inc. and Wayne Rosa, Energy and Maintenance Manager, Food Lion, LLC.

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

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

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

On February 20, 2018, the Public Staff filed supplemental testimony and exhibits of witnesses Boswell, Hinton, Junis, Maness, Moore, and Saillor. The Public Staff filed the second supplemental testimony and exhibits of witnesses Hinton and Boswell on March 19, 2018. On March 9, 2018, the AGO filed the supplemental testimony of witness Woolridge. On March 20, 2018, the Tech Customers filed the supplemental testimony of Dr. Sharon Brown-Hruska, Managing Director, NERA, and witness Strunk.

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

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

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

Franklin:	David Watters, Selma Sparks, The Honorable Kevin Corbin, Donn Erickson, Henry Horton, Fred Crawford, Virginia Bugash, Avram Friedman, Debra Lawley, Bob Boyd, Tamara Zwinak, Margaret Crownover, Janet Wilde, and Robert Smith
Greensboro:	Sharon Goodson, John Carter, Aaron Martin, Clarence Wright, Ruth Martin, Deborah Graham, Hester Petty, David Sevier, Joan Bass, John Merrell, Marta Concepcion, Gayle Tuch, August Preschle, Claudia Lange, Harry Phillips, Rexanne Bishop, Tim Stevenson, Taina Diaz-Reyes, Debbie Smith, Doug Ruder, Gladys Ellison, John Robins, Henry Fansler, Rachel Kriegsman, David Freeman, John Motsinger, Lib Hutchby, and Megan Longstreet
Charlotte:	Brian Kasher, Mary Anne Hitt, Yvette Baker, Melvina Williams, Lilly Taylor, Steve English, Nancy Nicholson, Sally Kneidel, Callina Satterfield, Amy Brown, Roger Hollis, Kent Crawford, Ritchie Johnson, Ernie McLaney, Willie Dawson, Pat Moore, Beth Henry, James Sprouse, Charles Talley, June Blotnick, Charles King, Meg Houlihan, Steve Copulsky, Elaine Jones, Christian Cano, Joel Segal, Kathy Sparrow, Rick Lauer, Nicholas Rose, Wells Eddleman, Walker Spruill, Violet Mitchell, and Holliday Adams

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

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

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

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

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

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

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

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

FINDINGS OF FACT

Jurisdiction

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

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

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

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

The Application

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

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

The Stipulation

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

8. The revenue requirement effect of the Stipulation is shown in Boswell Third Supplemental and Stipulation Exhibit 1 Corrected[1] and Revised McManeus Stipulation Exhibit 1 – Updated for Post-Hearing Issues,[2] which provide sufficient support for the annual revenue required on the issues agreed to in the Stipulation.

9. The Stipulation is the product of the give-and-take in settlement negotiations between the Stipulating Parties, is material evidence in this proceeding, and is entitled to be given appropriate weight in this proceeding, along with other evidence from the Company and intervenor

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

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

parties, and along with statements from customers of the Company as well as testimony of public witnesses concerning the Company's Application.

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

<u>**Capital Structure, Cost of Capital, and Overall Rate of Return**</u>

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

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

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

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

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

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

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

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

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

Adjustments to Cost of Service

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

State EDIT

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

Customer Connect

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

Lee Combined Cycle

23. At the time the Stipulation was filed on February 28, 2018, the Company's Lee CC plant was almost complete, but not anticipated to come online until March 2018. Pursuant to the Stipulation, DEC withdrew its adjustment to include incremental operation and maintenance (O&M) expenses for the Lee CC, and the Public Staff withdrew its displacement adjustment for the Lee CC; the Stipulating Parties therefore agreed that the appropriate level of ongoing O&M expense to be included in rates is $0. The Stipulating Parties further agreed that the appropriate amortization period for the deferred expenses is four years. The Stipulation additionally requires that the Company provide the Public Staff and the Commission with the final cost amounts to be included in this proceeding for determining the impact of the Lee CC on the overall revenue adjustment approved by the Commission by March 23, 2018. The Stipulation provides that the Public Staff utilize these amounts to work with the Company to file with the Commission, on or before April 6, 2018, the Stipulating Parties' final recommendation with regard to the Lee CC-related revenue requirement, including Lee CC deferred costs, using the methodology recommended by the Public Staff in this proceeding, excluding the appropriate amortization period for Lee CC deferred costs. The Stipulating Parties further agreed that it would be appropriate to hold the record open until April 22, 2018, for the sole purpose of allowing the Company to file an affidavit indicating that the plant has closed to service for operational and accounting purposes and that it is used and useful for the benefit of customers. This provision of the Stipulation is just and reasonable to all parties in light of all of the evidence presented.

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

Requested Coal Combustion Residuals (CCR) Fuel Costs

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

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

Base Fuel Factor

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

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

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

Coal Inventory

27. As set forth in Paragraph III.I. of the Stipulation, DEC shall reduce the amount of coal inventory included in working capital. An increment rider shall be established, effective on the same date as the new base rates approved in this Order, and continuing until inventory levels

reach a 35-day supply, to allow the Company to recover the additional costs of carrying coal inventory in excess of a 35-day supply (priced at $73.23 per ton). This rider shall terminate on the earlier of: (a) May 31, 2020, or (b) the last day of the month in which the Company's actual coal inventory levels return to a 35-day supply on a sustained basis, as defined in the Stipulation. The reduction to coal inventory included in working capital and the establishment of the increment rider, as set forth in the Stipulation, is just and reasonable to all parties in light of all the evidence presented.

Cost of Service Allocation Methodology

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

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

Lead-Lag Study

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

Rate Design

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

Vegetation Management, Quality of Service, and Service Regulations

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

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

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

Acceptance of Stipulation

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

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

ELECTRIC – RATE INCREASE

Basic Facilities Charge (BFC)

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

Customer Usage

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

Advanced Metering Infrastructure (AMI)

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

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

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

Customer Data

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

Power Forward and the Grid Rider

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

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

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

Lee Nuclear

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

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

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

48. DEC's project development costs incurred for the Lee Nuclear Project, with the exception of costs relating to a Visitors' Center and the allowance for funds used during construction (AFUDC) for 2018, which were recommended for disallowance by the Public Staff and that the Company agreed to exclude,[1] are reasonable and prudent and should be amortized over a 12-year period, as requested by the Company.

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

Nuclear Decommissioning Trust Fund (NDTF)

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

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

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

ELECTRIC – RATE INCREASE

Depreciation

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

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

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

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

Tax Changes

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

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

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

  (i) For Federal EDIT protected under Internal Revenue Service (IRS) normalization rules, in accordance with those rules;
  (ii) For Federal EDIT not protected by normalization rules, but related to property, plant and equipment (PP&E), over a 20-year period; and

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

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

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

58. It is appropriate to reflect the 21% Federal corporate income tax rate specified in the Tax Act in DEC's revenue requirement in this proceeding. It is further appropriate to deny

DEC's proposed $200 million cash flow mitigation measure and to require DEC to maintain all EDIT resulting from the Tax Act in a regulatory liability account pending flow back with interest reflected at the overall weighted cost of capital approved in this case of 7.35% in three years or in DEC's next general rate case proceeding, whichever is sooner.

Job Retention Rider (JRR)

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

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

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

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

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

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

CCR Cost Deferral

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

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

67. It is reasonable and appropriate to add a return based on the net-of-tax overall cost of capital approved in DEC's last general rate case to the amount of deferred coal ash costs, as

approved in this proceeding, for the period through the effective date of rates approved in this proceeding. The federal tax rate appropriate to use for the 2018 portion of the carrying costs is 21%.

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

Recovery of CCR Costs

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

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

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

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

Provisional CCR Cost Recovery

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

CCR Allocation Guidelines

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

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

Insurance Litigation

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

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

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

Accounting for Deferred Costs

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

Revenue Requirement

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

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

of the filing. DEC should file schedules summarizing the gross revenue and the rate of return that the Company should have the opportunity to achieve based on the Commission's findings and determinations in this proceeding.

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

Just and Reasonable Rates

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

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

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

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

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

On August 25, 2017, DEC filed its Application and initial direct testimony and exhibits, seeking a net increase of approximately $611 million, or 12.8%, in its annual electric sales revenues from its North Carolina retail electric operations. DEC is also proposing the Grid Rider to recover ongoing costs related to the modernization of the Company's electric grid, referred to as the Power Forward initiative. The Grid Rider brings the total impact of the Company's rate request in its Application to approximately $647 million, a 13.6% increase across all customer classes. DEC submitted evidence in this case with respect to revenue, expenses, and rate base using a test period consisting of the 12 months ended December 31, 2016, updated for certain known and actual changes. After rebuttal and supplemental filings, the amount of the Company's requested revenue requirement increased to $700 million. The Company also requested a Grid Rider to recover $35.2 million in its first year.

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

ELECTRIC – RATE INCREASE

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

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

Witness Fountain also outlined the coal ash basin closure costs the Company is seeking to recover in this case and emphasized that the Company is not seeking recovery of any costs incurred in response to the release of coal ash from the Dan River Steam Station in February 2014. Id. at 169-70, 173-77. The Company's Application also requests that the Commission permit DEC to cancel the Lee Nuclear Project as originally envisioned[1] and to recover costs for project development work completed for the project. Id. at 167-68. Finally, witness Fountain noted that the cost increases requested in this case are partially offset by the return of a deferred tax liability to customers. Id. at 170.

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

Witness Fountain also described the Company's ongoing efforts to mitigate customers' rate impacts. Id. at 180-85. He stated that to help customers reduce bills, the Company is continuing to expand and enhance its portfolio of DSM and EE programs. Id. at 182. According to witness Fountain, the Company offers customers more than a dozen energy-saving programs for every type of energy user and budget; EE programs currently save its customers in the Carolinas over 4.3 billion kWh annually, or over $357 million, which is about 5.4% of total retail kWh sales. Id. Combined, DEC's demand-side management (DSM) and Energy efficiency (EE) programs offset capacity requirements by the equivalent of over seven power plants. Id. Witness Fountain also described how the Company's Share the Warmth program helps low-income individuals and

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

families cover home energy bills. Id. at 183. Since its inception, the program has provided approximately $26 million in assistance to DEC customers in North Carolina. Id. He explained that the Company allows customers a bill management option that allows them to spread out the impacts of seasonal fluctuations into 12 equal monthly payments. Id. at 184. The Company also offers payment arrangements to eligible customers who are having difficulty paying their entire bill by the due date. Id.

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

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

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

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

Witness Fountain explained that the Stipulation would resolve many, but not all, of the revenue requirement issues between the Company and the Public Staff.[1] Tr. Vol. 6, p. 218. He outlined the key aspects of the Stipulation as follows:

Cost of Capital – The Stipulating Parties have agreed to a rate of return on equity of 9.9%, based upon a capital structure containing 52% equity and 48% debt as described by Company

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

witnesses Hevert and De May. Id. The Company's debt cost rate shall be set at 4.59%. Id. at 218-19. The resulting weighted average rate of return is 7.35%. Id. at 219.

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

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

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

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

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

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

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

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

Witness Fountain testified that he attended public witness hearings held by the Commission in this matter and followed the consumer statement positions filed in this docket. Tr. Vol. 6, p. 221. He listened to customers' concerns about the impacts of any rate increase on their families and businesses and noted that the Company is very mindful of these concerns. Id. Witness Fountain believes that the concessions the Company made in the Stipulation fairly balance the needs of DEC's customers with the Company's need to recover substantial investments made in order to continue to comply with regulatory requirements and safely provide high quality electric service to its customers. Id. at 222. He added that the Company's rates need to be adjusted to reflect these investments. Id. Witness Fountain stated that given the size of the necessary capital and compliance expenditures the Company is facing, it is essential that DEC maintain its financial strength and credit quality, so that it will be in a position to finance these needs on reasonable terms for the benefit of its customers. Id. In his opinion, the Company has been able to strike that balance with the Stipulation. Id.

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

Public Staff witnesses Boswell, Maness, and Parcell also supported the Stipulation. Witness Boswell stated that the most important benefits of the Stipulation are an aggregate reduction in the increase of specific expense items requested in the Company's application and the avoidance of protracted litigation by the Stipulating Parties before the Commission and, possibly, the appellate courts. Tr. Vol. 26, p. 628. Witness Boswell also presented schedules showing the

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

financial impact of the Stipulation. Witness Maness testified on the impact of the Stipulation on the unresolved CCR issues, and witness Parcell stated that the Stipulation reflects the result of good faith "give-and-take" and compromise-related negotiations among the parties. Tr. Vol. 26, p. 890.

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

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

348 N.C. at 466, 500 S.E.2d at 703. However, as the Court made clear in CUCA II, the fact that fewer than all of the parties have adopted a settlement does not permit the Court to subject the Commission's order adopting the provisions of a nonunanimous stipulation to a "heightened standard" of review. 351 N.C. at 231, 524 S.E.2d at 16. Rather, the Court said that Commission approval of the provisions of a nonunanimous stipulation "requires only that the Commission ma[k]e an independent determination supported by substantial evidence on the record [and] ... satisf[y] the requirements of Chapter 62 by independently considering and analyzing all the evidence and any other facts relevant to a determination that the proposal is just and reasonable to all parties." Id. at 231-32, 524 S.E.2d at 16.

The Commission gives substantial weight to the testimony of the Company and Public Staff witnesses regarding the Stipulation and the Lighting Settlement, and finds and concludes that the Stipulation and the Lighting Settlement are the product of the "give-and-take" of the settlement negotiations between DEC and the Public Staff, as well as between DEC and NCLM, and the Cities of Concord, Kings Mountain, and Durham, in an effort to appropriately balance the Company's need for rate relief with the impact of such rate relief on customers. The Stipulation is, therefore, material evidence to be given appropriate weight in this proceeding.

Ample evidence exists in the record to support all of the provisions of the Stipulation, including those which have been contested by some intervenors other than the Stipulating Parties. Accordingly, the Commission is fully justified in adopting the Stipulation through the exercise of its own independent judgment, and finding and concluding through such independent judgment that the Stipulation "is just and reasonable to all parties in light of all the evidence presented."

CUCA I, 348 N.C. at 466, 500 S.E.2d at 703. The Commission hereby adopts the Lighting Settlement in its entirety, and its conclusions as to the individual provisions are discussed in the rate design section of this order. The Commission hereby adopts the Stipulation in its entirety, and its conclusions as to the individual provisions of the Stipulation are set forth more fully below.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11-19

The evidence supporting these findings of fact and conclusions is contained in the Company's verified Application and Form E-1, the testimony and exhibits of the public witnesses, the testimony and exhibits of Company witnesses Hevert and De May, Public Staff witness Parcell, Commercial Group witnesses Chriss and Rosa, AGO witness Woolridge, CIGFUR III witness Phillips, Tech Customers witness Strunk and CUCA witness O'Donnell, and the entire record of this proceeding.

Rate of Return on Equity

In its Application, the Company requested approval for its rates to be set using a rate of return on equity of 10.75%. The Stipulation provides for a rate of return on equity of 9.9%, which is a decrease from the 10.2% level authorized by the Commission in the Company's last rate case. For the reasons set forth herein, the Commission finds that a rate of return on equity of 9.9% is just and reasonable.

Rate of return on equity, also referred to as the cost of equity capital, is often one of the most contentious issues to be addressed in a rate case, even in a case such as this one in which a Stipulation between the utility and the consumer advocate has been reached. In the absence of a settlement agreed to by all parties, the Commission must still exercise its independent judgment and arrive at its own independent conclusion as to all matters at issue, including the rate of return on equity. See, e.g., CUCA I, 348 N.C. at 466, 500 S.E.2d at 707. In order to reach an appropriate independent conclusion regarding the rate of return on equity, the Commission should evaluate the available evidence, particularly that presented by conflicting expert witnesses. State ex rel. Utils. Comm'n v. Cooper, 366 N.C. 484, 739 S.E.2d 541, 546-47 (2013) (Cooper I). In this case, the expert witness evidence relating to the Company's cost of equity capital was presented by Company witness Hevert, Public Staff witness Parcell, Commercial Group witnesses Chriss and Rosa, AGO witness Woolridge, CIGFUR III witness Phillips, Tech Customers witness Strunk, and CUCA witness O'Donnell. No rate of return on equity expert evidence was presented by any other party.

In addition to its evaluation of the expert evidence, the Commission must also make findings of fact regarding the impact of changing economic conditions on customers when determining the proper rate of return on equity for a public utility. Cooper I, 366 N.C. 484, 739 S.E.2d at 548. This was a factor newly announced by the Supreme Court in its Cooper I decision, and which was not previously required by the Commission, the Court of Appeals, or the Supreme Court as an element to be considered in connection with the Commission's determination of an appropriate rate of return on equity. The Commission's discussion of the evidence with respect to the findings required by Cooper I is set out in detail in this Order.

Cooper I was the result of the Supreme Court's reversal and remand of the Commission's approval of the agreement regarding the rate of return on equity in a stipulation between the Public Staff and DEC in DEC's 2011 Rate Case. The Commission has had occasion to apply both prongs of Cooper I in subsequent orders, specifically the following:

- Order Granting General Rate Increase in DEP's 2013 Rate Case, Docket No. E-2, Sub 1023 (May 30, 2013) (2013 DEP Rate Order), which was affirmed by the Supreme Court in State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 444, 761 S.E.2d 640 (2014) (Cooper III);[1]
- Order on Remand resulting from the Supreme Court's Cooper I decision, in Docket No. E-7, Sub 989 (October 23, 2013) (DEC Remand Order), which was affirmed by the Supreme Court in State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 644, 766 S.E.2d 827 (2014) (Cooper IV);
- Order Granting General Rate Increase in DEC's 2013 Rate Case, Docket No. E-7, Sub 1026 (September 24, 2013) (2013 DEC Rate Order), which was affirmed by the Supreme Court in State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 741, 767 S.E.2d 305 (2015) (Cooper V);
- Order on Remand resulting from the Supreme Court's Cooper II decision, in Docket No. E-22, Sub 479 (July 23, 2015) (DNCP Remand Order), which was not appealed to the Supreme Court;
- Order Approving Rate Increase and Cost Deferrals and Revising PJM Regulatory Conditions, in Docket No. E-22, Sub 532, dated December 22, 2016 (2016 DNCP Rate Order), which was not appealed to the Supreme Court; and
- Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase, in Docket No. E-2, Sub 1142, dated February 23, 2018 (2018 DEP Rate Order).

In order to give full context to the Commission's decision herein and to elucidate its view of the requirements of the General Statutes as they relate to rate of return on equity, as interpreted by the Supreme Court in Cooper I, the Commission deems it important to provide in this Order an overview of the general principles governing this subject.

A. Governing Principles in Setting the Rate of Return on Equity

First, there are, as the Commission noted in the 2013 DEP Rate Order, constitutional constraints upon the Commission's rate of return on equity decisions established by the United States Supreme Court decisions in Bluefield Waterworks & Improvement Co., v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679 (1923) (Bluefield), and Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944) (Hope):

> To fix rates that do not allow a utility to recover its costs, including the cost of equity capital, would be an unconstitutional taking. In assessing the impact of changing economic conditions on customers in setting an ROE, the Commission must still provide the public utility with the opportunity, by sound management, to

[1] An intervening Cooper case, State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 430, 758 S.E.2d 635 (2014) (Cooper II), arose from the 2012 Rate Case by Dominion North Carolina Power (DNCP) and resulted in a remand to the Commission, inasmuch as the Commission's Order in that case predated Cooper I.

> (1) produce a fair profit for its shareholders, in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital. State ex rel. Utils. Comm'n v. General Telephone Co. of the Southeast, 281 N.C. 318, 370, 189 S.E.2d 705, 757 (1972). As the Supreme Court held in that case, these factors constitute "the test of a fair rate of return declared" in Bluefield and Hope. Id.

2013 DEP Rate Order, at 29.

Second, the rate of return on equity is, in fact, a cost. The return that equity investors require represents the cost to the utility of equity capital. In his dissenting opinion in Missouri ex rel. Southwestern Bell Tel. Co. v. Missouri Pub. Serv. Comm'n, 262 U.S. 276 (1923), Justice Brandeis remarked upon the lack of any functional distinction between the rate of return on equity (which he referred to as a "capital charge") and other items ordinarily viewed as business costs, including operating expenses, depreciation, and taxes:

> Each is a part of the current cost of supplying the service; and each should be met from current income. When the capital charges are for interest on the floating debt paid at the current rate, this is readily seen. But it is no less true of a legal obligation to pay interest on long-term bonds...and it is also true of the economic obligation to pay dividends on stock, preferred or common.

Id. at 306. (Brandeis, J. dissenting) (emphasis added). Similarly, the United States Supreme Court observed in Hope, "From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business...[which] include service on the debt and dividends on the stock." Hope, 320 U.S. at 591, 603.

Leading academic commentators also define rate of return on equity as the cost of equity capital. Professor Charles Phillips, for example, states that "the term 'cost of capital' may be defined as the annual percentage that a utility must receive to maintain its credit, to pay a return to the owners of the enterprise, and to ensure the attraction of capital in amounts adequate to meet future needs." Phillips, Charles F., Jr., The Regulation of Public Utilities (Public Utilities Reports, Inc. 1993), at 388. Professor Roger Morin approaches the matter from the economist's viewpoint:

> While utilities enjoy varying degrees of monopoly in the sale of public utility services, they must compete with everyone else in the free open market for the input factors of production, whether it be labor, materials, machines, or capital. The prices of these inputs are set in the competitive marketplace by supply and demand, and it is these input prices which are incorporated in the cost of service computation. This is just as true for capital as for any other factor of production. Since utilities must go to the open capital market and sell their securities in competition with every other issuer, there is obviously a market price to pay for the capital they require, for example, the interest on capital debt, or the expected return on equity.

* * *

> [T]he cost of capital to the utility is synonymous with the investor's return, and the cost of capital is the earnings which must be generated by the investment of that capital in order to pay its price, that is, in order to meet the investor's required rate of return.

Morin, Roger A., Utilities' Cost of Capital (Public Utilities Reports, Inc. 1984), at 19-21 (emphasis added). Professor Morin adds: "The important point is that the prices of debt capital and equity capital are set by supply and demand, and both are influenced by the relationship between the risk and return expected for those securities and the risks expected from the overall menu of available securities." Id. at 20 (emphasis added).

Changing economic circumstances as they impact DEC's customers may affect those customers' ability to afford rate increases. For this reason, customer impact weighs heavily in the overall rate setting process, including, as set out in detail elsewhere in this Order, the Commission's own decision of an appropriate authorized rate of return on equity. In addition, in the event of a settlement, customer impact no doubt influences the process by which the parties to a rate case decide to settle contested matters and the level of rates achieved by any such settlement.

However, a customer's ability to afford a rate increase has absolutely no impact upon the supply of or the demand for capital. The economic forces at work in the competitive capital market determine the cost of capital – and, therefore, the utility's required rate of return on equity. The cost of capital does not go down because some customers may find it more difficult to pay for an increase in electricity prices as a result of prevailing adverse economic conditions, any more than the cost of capital goes up because some customers may be prospering in better times.

Third, the Commission is and must always be mindful of the North Carolina Supreme Court's command that the Commission's task is to set rates as low as possible consistent with the dictates of the United States and North Carolina Constitutions. State ex rel. Utils. Comm'n v. Pub. Staff-N. Carolina Utils. Comm'n, 323 N.C. 481, 490, 374 S.E.2d 361, 370 (1988) (Public Staff). Further, and echoing the discussion above concerning the fact that rate of return on equity represents the cost of equity capital, the Commission must execute the Supreme Court's command "irrespective of economic conditions in which ratepayers find themselves." 2013 DEP Rate Order, at 37. The Commission noted in that Order:

> The Commission always places primary emphasis on consumers' ability to pay where economic conditions are difficult. By the same token, it places the same emphasis on consumers' ability to pay when economic conditions are favorable as when the unemployment rate is low. Always there are customers facing difficulty in paying utility bills. The Commission does not grant higher rates of return on equity when the general body of ratepayers is in a better position to pay than at other times, which would seem to be a logical but misguided corollary to the position the Attorney General advocates on this issue.

Id. Indeed, in Cooper I the Supreme Court emphasized "changing economic conditions" and their impact upon customers. Cooper I, 366 N.C. at 484, 739 S.E.2d at 548.

Fourth, while there is no specific and discrete numerical basis for quantifying the impact of economic conditions on customers, the impact on customers of changing economic conditions is embedded in the rate of return on equity expert witnesses' analyses. The Commission noted this in the 2013 DEP Rate Order: "This impact is essentially inherent in the ranges presented by the return on equity expert witnesses, whose testimony plainly recognized economic conditions – through the use of econometric models – as a factor to be considered in setting rates of return." 2013 DEP Rate Order, at 38.

Fifth, under long-standing decisions of the North Carolina Supreme Court, the Commission's subjective judgment is a necessary part of determining the authorized rate of return on equity. Public Staff, 323 NC 481, 490, 374 S.E.2d 361, 369. As the Commission also noted in the 2013 DEP Rate Order:

> Indeed, of all the components of a utility's cost of service that must be determined in the ratemaking process, the appropriate ROE [rate of return on equity] the one requiring the greatest degree of subjective judgment by the Commission. Setting an ROE [rate of return on equity] for regulatory purposes is not simply a mathematical exercise, despite the quantitative models used by the expert witnesses. As explained in one prominent treatise,
>
>> Throughout all of its decisions, the [United States] Supreme Court has formulated no specific rules for determining a fair rate of return, but it has enumerated a number of guidelines. The Court has made it clear that confiscation of property must be avoided, that no one rate can be considered fair at all times and that regulation does not guarantee a fair return. The Court also has consistently stated that a necessary prerequisite for profitable operations is efficient and economical management. Beyond this is a list of several factors the commissions are supposed to consider in making their decisions, but no weights have been assigned.
>>
>> The relevant economic criteria enunciated by the Court are three: financial integrity, capital attraction and comparable earnings. Stated another way, the rate of return allowed a public utility should be high enough: (1) to maintain the financial integrity of the enterprise, (2) to enable the utility to attract the new capital it needs to serve the public, and (3) to provide a return on common equity that is commensurate with returns on investments in other enterprises of corresponding risk. These three economic criteria are interrelated and have been used widely for many years by regulatory commissions throughout the country in determining the rate of return allowed public utilities.
>>
>> In reality, the concept of a fair rate of return represents a "zone of reasonableness." As explained by the Pennsylvania commission:

> There is a range of reasonableness within which earnings may properly fluctuate and still be deemed just and reasonable and not excessive or extortionate. It is bounded at one level by investor interest against confiscation and the need for averting any threat to the security for the capital embarked upon the enterprise. At the other level it is bounded by consumer interest against excessive and unreasonable charges for service.
>
> As long as the allowed return falls within this zone, therefore, it is just and reasonable. . . . It is the task of the commissions to translate these generalizations into quantitative terms.

Charles F. Phillips, Jr., The Regulation of Public Utilities, 3d ed. 1993, pp. 382. (notes omitted).

2013 DEP Rate Order, pp. 35-36.

Thus, the Commission must exercise its subjective judgment so as to balance two competing rate of return on equity-related factors – the economic conditions facing the Company's customers and the Company's need to attract equity financing in order to continue providing safe and reliable service.

The Supreme Court in Cooper V affirmed the 2013 DEC Rate Order, in which this framework was fully articulated. But to the framework the Commission can add additional factors based upon the Supreme Court's decisions in Cooper III, Cooper IV, and Cooper V. Specifically, the Supreme Court held that nothing in Cooper I requires the Commission to "quantify" the influence of changing economic conditions upon customers (see, e.g., Cooper V, 367 N.C. at 745-46, 767 S.E.2d at 308; Cooper IV, 367 N.C. at 650, 766 S.E.2d at 829; Cooper III, 367 N.C. at 450, 761 S.E.2d at 644), and, indeed, the Supreme Court reiterated that setting the rate of return on equity is a function of the Commission's subjective judgment: "Given th[e] subjectivity ordinarily inherent in the determination of a proper rate of return on common equity, there are inevitably pertinent factors which are properly taken into account but which cannot be quantified with the kind of specificity here demanded by [the appellant]." Cooper III, 367 N.C. at 450, 761 S.E.2d at 644, quoting Public Staff, 323 N.C. at 498; 374 S.E.2d at 370.

Finally, the Supreme Court discussed with approval the Commission's reference to and reliance upon expert witness testimony that used econometric models that the Commission had noted "inherently" contained the effects of changing economic circumstances upon customers, and also discussed with approval the Commission's reference to and reliance upon expert witness testimony correlating the North Carolina economy with the national economy. See, e.g., Cooper V, 367 N.C. at 747, 767 S.E.2d at 308; Cooper III, 367 N.C. at 451, 761 S.E.2d at 644.

It is against this backdrop of overarching principles that the Commission turns to the evidence presented in this case.

B. Application of the Governing Principles to the Rate of Return Decision

1. Evidence from Expert Witnesses on Cost of Equity Capital

Company witness Hevert recommended in his direct testimony a rate of return on equity of 10.75%, which was slightly above the midpoint of his recommended range of 10.25% to 11.00%. Witness Hevert's direct testimony explained the importance of a utility being allowed to earn a rate of return on equity that is adequate to attract capital at reasonable terms, under varying market conditions, and that will enable the utility to provide safe, reliable electric service while maintaining its financial integrity. Witness Hevert explained that unlike the cost of debt, the cost of equity is not observable and must be estimated based on market data. Witness Hevert noted that since all financial models are subject to various assumptions and constraints, equity analysts and investors tend to use multiple methods to develop their return recommendations. Witness Hevert used the Constant Growth and Multi-Stage forms of the Discounted Cash Flow (DCF) model; the Capital Asset Pricing Model (CAPM); and the Bond Yield Risk Premium. He testified that his recommendation also takes into consideration factors such as DEC's generation portfolio and the risks associated with environmental regulations, flotation costs, and DEC's planned capital investment program. Witness Hevert also provided extensive testimony concerning the capital market environment and addressed the effect those market conditions have on the return investors require in order to commit their capital to equity securities. Witness Hevert also focused upon capital market conditions as they affect the Company's customers in North Carolina.

To calculate the dividend yield for the DCF, witness Hevert used the average daily closing prices for the 30-trading days, 90-trading days, and 180-trading days as of June 16, 2017. He then calculated the DCF results using each of the following growth terms:

- The Zack's consensus long-term earnings growth estimates;
- The First Call consensus long-term earnings growth estimates; and
- The Value Line earnings growth estimates.

Witness Hevert testified that for each proxy company he calculated the mean, mean high, and mean low results. For the mean result, he combined the average of the EPS growth rate estimates reported by Value Line, Zacks, and First Call with the subject company's dividend yield for each proxy company and then calculated the average result for those estimates. His constant growth DCF results ranged from 7.91% to 9.83%.[1]

He testified with regard to his constant growth DCF that regardless of the method employed, an authorized rate of return on equity that is well below returns authorized for other utilities (1) runs counter to the Hope and Bluefield "comparable risk" standard, (2) would place DEC at a competitive disadvantage, and (3) makes it difficult for DEC to compete for capital at reasonable terms.

[1] Table 11 in the rebuttal testimony of witness Hevert contains updated analytical results for his DCF, CAPM, and Bond Yield Risk Premium analyses. However, in summarizing his rebuttal testimony, witness Hevert testified that "[n]one of their [opposing witnesses] arguments caused me to revise my conclusions or recommendations."

DEC witness Hevert testified that the Multi-Stage DCF model, which is an extension of the constant growth form, enables the analyst to specify growth rates over three distinct stages (i.e., time periods). As with the constant growth form of the DCF model, the Multi-Stage form defines the cost of equity as the discount rate that sets the current price equal to the discounted value of future cash flows. He testified in the first two stages, "cash flows" are defined as projected dividends. In the third stage, "cash flows" equal both dividends and the expected price at which the stock will be sold at the end of the period (i.e., the terminal price). He calculated the terminal price based on the Gordon model, which defines the price as the expected dividend divided by the difference between the cost of equity (i.e., the discount rate) and the long-term expected growth rate.

Witness Hevert testified that his Multi-Stage DCF long-term growth rate was 5.38% based on the real gross domestic product (GDP) growth rate of 3.22% from 1929 through 2016 and an inflation rate of 2.09%. He testified that the GDP growth rate is calculated as the compound growth rate in companies. Witness Hevert testified that his Multi-Stage DCF analysis produced a range of results from 8.70% to 9.31%. Using the proxy group price-to-earnings ratio to calculate a terminal valve, his Multi-Stage DCF produced a range of results from 9.52% to 11.05%.

Witness Hevert testified that for his CAPM analysis risk-free rate, he used the current 30-day average yield on 30-year Treasury bonds of 2.90% and the near-term projected 30-year Treasury yield of 3.40%. For the market risk premium, he calculated the market capitalization weighted average total return based on the constant growth DCF model for each of the Standard & Poor's (S&P) 500 companies using data from Bloomberg and Value Line. He then subtracted the current 30-year Treasury yield from that amount to arrive at the market DCF-derived forward looking market risk premium estimate. Witness Hevert used the beta coefficients reported by Bloomberg and Value Line. He testified that his CAPM analysis suggested a rate of return on equity range of 9.11% to 11.05%.

Witness Hevert testified that for his risk premium analysis, he estimated the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds. He testified that the equity risk premium is typically estimated using a variety of approaches, some of which incorporate ex-ante, or forward-looking, estimates of the cost of equity, and others that consider historical, or ex-post, estimates. An alternative approach is to use actual authorized returns for electric utilities to estimate the equity risk premium.

Witness Hevert testified that he first defined the risk premium as the difference between the authorized rate of return on equity and the then-prevailing level of the long-term 30-year Treasury yield. He then gathered data for 1,517 electric utility rate proceedings between January 1980 and June 16, 2017. In addition to the authorized rate of return on equity, he also calculated the average period between the filing of the case and the date of the final order (the "lag period"). In order to reflect the prevailing level of interest rates during the pendency of the proceedings, he calculated the average 30-year Treasury yield over the average lag period of approximately 201 days. He testified that to analyze the relationship between interest rates and the equity risk premium, he used regression analyses. Witness Hevert testified that based upon the regression coefficients, the implied rate of return on equity in his risk premium analysis is between 9.97% and 10.33%.

Public Staff witness Parcell performed three rate of return on equity analyses using the constant growth DCF, the CAPM, and comparable earnings.

Witness Parcell considered five indicators of growth in his DCF analyses:

- Years 2012-2016 (five-year average) earnings retention, or fundamental growth (per Value Line);
- Five-year average of historic growth in EPS, dividends per share (DPS), and book value per share (BVPS) (per Value Line);
- Years 2017, 2018, and 2020-2022 projections of earnings retention growth (per Value Line);
- Years 2014-2016 to 2020-2022 projections of EPS, DPS, and BVPS (per Value Line); and
- Five-year projections of EPS growth (per First Call).

Witness Parcell testified that investors do not always use one single indicator of growth. His analysis using these five dividend growth indicators materially differed from DEC witness Hevert's sole use of analysts' predictions of EPS growth to determine DCF dividend growth.

Witness Parcell performed his DCF analysis on his proxy group of 11 companies, where using only the high mean growth rate the cost of capital was 8.2%, and the Hevert proxy group of 20 companies, where using only the highest mean growth rate the cost of capital was 9.2%. He recommended a DCF rate of return on equity of 8.7% for DEC as the mid-point of the two highest mean growth rates.

Witness Parcell testified that the constant growth DCF model currently produced cost of equity results that are lower than has been the case in recent years. This is, in part, a reflection of the decline in capital costs (e.g., in terms of interest rates). He believed that the constant growth DCF model remains relevant and informative. It was also his personal experience that of all available cost equity models, this model is used the most by cost of capital witnesses. Nevertheless, in order to be conservative, he focused only on the highest of the DCF results in making his recommendations.

Witness Parcell testified that he did not perform a multi-stage DCF, as he did not believe that the results of a properly-constructed multi-stage DCF would materially differ from the results of his constant-growth DCF.

Public Staff witness Parcell also performed a CAPM analysis, which describes the relationship between a security's investment risk and its market rate of return. For his risk-free rate, he used the three-month average yield for 20-year Treasury bonds. For the beta, which indicates the security's variability of return relative to the return variability of the overall capital market, he used the most recent Value Line beta for each company in his proxy group. He calculated the risk premium by comparing the annual returns on equity of the S&P 500 with the actual yields of the 20-year Treasury bonds, by comparing the total returns (i.e., dividends/interest plus gains/losses) for the S&P 500 group as well as long-term government bonds, using both the arithmetic and geometric means. These analyses revealed the average expected risk premium to be 5.8%. His CAPM results collectively indicated a rate of return on equity of 6.3% to 6.7% for the Parcell and Hevert proxy groups.

However, witness Parcell did not directly consider his CAPM results. He testified that he has conducted CAPM studies in his cost of equity analyses for many years. He stated that it is apparent that the CAPM results are currently significantly less than the DCF and comparable earnings results. According to his testimony, there are two reasons for the lower CAPM results. First, risk premiums are lower currently than was the case in prior years. This is the result of lower equity returns that have been experienced beginning with the Great Recession and continuing over the past several years. This is also reflective of a decline in investor expectations of equity returns and risk premiums. Second, the level of interest rates on Treasury bonds (i.e., the risk free rate) has been lower in recent years. This is partially the result of the actions of the Federal Reserve System to stimulate the economy. This also impacts investor expectation of returns in a negative fashion.

Witness Parcell testified that, initially, investors may have believed that the decline in Treasury yields was a temporary factor that would soon be replaced by a rise in interest rates. However, this has not been the case, as interest rates have remained low and have continued to decline for the past six-plus years. As a result, he believes that it cannot be maintained that low interest rates (and low CAPM results) are temporary and do not reflect investor expectations.

Consequently, the CAPM results should be considered as one factor in determining the cost of equity for DEC. Even though witness Parcell did not factor the CAPM results directly into his cost of equity recommendation, he believed these lower results are indicative of the recent and continuing decline in utility costs of capital, including the cost of equity.

Witness Parcell also performed a comparable earnings analysis. He testified that the cost of capital is an opportunity cost: the prospective return available to investors from alternative investments of similar risk. He testified that the established legal standards are consistent with the opportunity cost principle. The two Supreme Court cases most frequently cited (Bluefield and Hope) hold that the return to the equity owners must be sufficient:

1. To maintain the credit of the enterprise and confidence in its financial integrity;
2. To permit the enterprise to attract required additional capital on reasonable terms; and
3. To provide the enterprise and its investors with an earnings opportunity commensurate with the returns available on investments in other enterprises having corresponding risks.

Witness Parcell further testified that the comparable earnings method normally examines the experienced and/or projected return on book common equity. The logic for examining returns on book equity follows from the use of original cost rate base regulation for public utilities, which uses a utility's book common equity to determine the cost of capital. This cost of capital is, in turn, used as the fair rate of return, which is then applied (multiplied) to the book value of rate base to establish the dollar level of capital costs to be recovered by the utility. This technique is thus consistent with the rate base rate of return methodology used to set utility rates. Witness Parcell applied the comparable earnings methodology by examining realized rates of return on equity for the Hevert and Parcell groups of proxy companies, as well as unregulated companies, and evaluated investor acceptance of these returns by reference to the resulting market-to-book ratios. Witness Parcell used the experienced rates of return on equity of the two proxy groups of utilities for the years 2002–2008 (the most recent business cycle) and 2009-2016 (the current business cycle), and projected return on equity for 2017, 2018, and 2020–2022 (the time periods estimated by Value Line). He testified that his results indicate that historic rates of return on equity of 9.7% to 11.0% have been adequate to produce market-to-book ratios of 145% to 159% for the groups of utilities. Furthermore, projected rates of return on equity for 2017, 2018, and 2020–2022 are within a range of 10.0% to 11.0% for the utility groups. These relate to market-to-book ratios of 178% or greater. He also noted that the rates of return on equity and market-to-book ratios of his proxy group, which all range over $20 billion in market value exceed those of witness Hevert's proxy group, which are not selected based upon size.

Witness Parcell also conducted a comparable earnings analysis examining the S&P's 500 Composite group. Over the same two business cycles, the group's average rates of return on equity ranged from 12.4% to 13.3%, with average market-to-books ranging between 233% and 275%. In order to apply the S&P 500 Composite rates of return on equity to the cost of equity for the proxy utilities, he compared the risk levels of the electric utilities and the competitive companies comparing the respective Value Line Safety Ranks, Value Line Betas, Value Line Financial Strengths, and S&P Stock Rankings, as shown on witness Parcell's direct testimony Exhibit DCP – 1, Schedule 12. Witness Parcell testified that based upon recent and prospective rates of return on equity and market-to-book analyses, his comparable earnings analysis indicates that the rate of return on equity for the proxy utilities is in the range of 9.0% to 10.0%.

Witness Parcell testified in support of the 9.9% rate of return on equity in the Stipulation. He explained that the Stipulation allows a 9.9% rate of return on equity and a capital structure of 52% equity and 48% long-term debt. Witness Parcell explained that the stipulated rate of return on equity is identical to the Commission's recent decisions in the 2016 DNCP Rate Order and the 2018 DEP Rate Order. The overall rate of return in the Stipulation is lower than the Company requested. Witness Parcell also explained that the 9.9% rate of return on equity falls within the range of his comparable earnings analysis.

Public Staff witness Parcell testified that in his experience, settlements are generally the result of good faith "give-and-take" and compromise-related negotiations among the parties of utility rate proceedings, involving the utility and other parties. He testified that it was also his understanding that settlements, as well as the individual components of the settlements, are often achieved by the respective parties' agreements to accept otherwise unacceptable individual aspects of individual issues in order to focus on other issues. He testified it was his understanding that the Stipulation is "global," except to the issues of Coal Ash (except for Coal Ash sales), Lee Nuclear return, nuclear decommissioning, updates, customer usage methodology, Federal income taxes, depreciation, Power Forward and the Grid Rider, and BFC.

Witness Parcell testified that it remains his position that should this be a fully litigated proceeding, he would continue to recommend a capital structure with 50% common equity and 50% long-term debt, a rate of return on equity of 9.10% (approximate mid-point of his range of 8.70% to 9.50%), and a cost of debt of 4.59%. However, given the benefits associated with entering into a settlement, it was his view that the cost of capital components of the Stipulation are a reasonable resolution to otherwise contentious issues.

Witness Parcell testified that each of the three cost of capital components - capital structure, rate of return on equity, and debt cost - can be considered as reasonable within the context of the Stipulation. He testified that DEC and the Public Staff, in their respective testimonies, proposed fundamentally different views on a number of issues, such as current market conditions and related current costs of common equity, as well as the appropriate capital structure. The Stipulation represents a compromise, or middle ground between their respective positions. He also testified that the cost of capital components of the Stipulation are reasonable within a broad negotiation and resolution of many of the issues in this proceeding.

With respect to the rate of return on equity component of the Stipulation, witness Parcell testified that DEC requested a rate of return on equity of 10.75%, which he noted in his direct testimony was well above industry norms in recent years. He recommended a 9.1% rate of return on equity (i.e., approximate mid-point of a rate of return on equity range of 8.70% to 9.50%, which was derived from his DCF model results of 8.7% and his comparable earnings results of 9.50%). Public Staff witness Parcell testified that while he continues to believe his specific 9.1% rate of return on equity recommendation is appropriate at this time, the upper end of his comparable earnings range of 9.0% to 10.0% contains the 9.9% Stipulation rate of return on equity level. He also stated that a 9.9% rate of return on equity is 0.80% above his 9.1% recommendation, and is 0.85% below DEC's 10.75% rate of return on equity request. As a result, the 9.9% rate of return on equity in the Stipulation is a "compromise" between DEC's and the Public Staff's respective proposals. The 9.9% rate of return on equity also reflects a reduction from the 10.2% authorized in DEC's last rate proceeding.

Witness Parcell testified that he had employed the comparable earnings method in virtually all of his cost of capital analyses going back to 1972. He testified that the comparable earnings analysis is based on the opportunity cost principle and is consistent with and derived from the Bluefield and Hope decisions of the U.S. Supreme Court, which are recognized as the primary standards for the establishment of a fair rate of return for a regulated public utility. The comparable earnings method is also consistent with the concept of rate base regulation for utilities, which employs the book value of both rate base and the capital financing rate base. He testified that his comparable earnings analyses consider the recent historic and prospective rates of return on equity for the groups of proxy utility companies utilized by himself and DEC witness Hevert. He testified that his conclusion of 9.0% to 10.0% reflects the actual rates of return on equity of the proxy companies, as well as the market-to-book ratios of these companies. Witness Parcell further testified that in the 2016 DNCP Rate Order, the Commission approved a settlement between DNCP and the Public Staff with a common equity ratio of 51.75% (versus the requested actual common equity ratio of 53.92%) and a rate of return on equity of 9.9% (versus the 10.5% requested), and in the 2018 DEP Rate Order, the Commission approved a common equity ratio of 52% versus the requested common equity ratio of 53%, and a rate of return on common equity of 9.9% versus the 10.75% DEP requested. The Commission approved the cost of capital components of both of those proposed settlements. Witness Parcell testified that the equity ratio and rate of return on equity in the Stipulation in the current DEC proceeding are consistent with those of the DNCP and DEP proceedings.

DEC witness Hevert also testified in support of the Stipulation on the agreed-upon rate of return on equity, capital structure, and overall rate of return contained in the Stipulation. He testified that although the stipulated rate of return on equity is below the lower bound of his recommended range of 10.25%, he recognized that the Stipulation represents negotiations among DEC and the Public Staff regarding otherwise contested issues. He testified that the Company has determined that the terms of the Stipulation, in particular the stipulated rate of return on equity and equity ratio, would be viewed by the rating agencies as constructive and equitable, and that he understands and respects that determination.

Witness Hevert testified that although the stipulated rate of return on equity falls below his recommended range, the low end of which is 10.25%, it is within the range of the analytical results presented in his direct and rebuttal testimonies. He testified that capital market conditions continue to evolve and as a consequence, the models used to estimate the cost of equity produce a wide range of estimates. Witness Hevert testified that he recognizes the benefits associated with DEC's decision to enter into the Stipulation and as such, it is his view that the 9.90% stipulated rate of return on equity is a reasonable resolution of an otherwise contentious issue.

Witness Hevert testified that he considered the stipulated rate of return on equity in the context of authorized returns for other vertically-integrated electric utilities. He testified that from January 2014 through February 2018, the average authorized rate of return on equity for vertically-integrated electric utilities was 9.81%, only nine basis points from the stipulated rate of return on equity. Of the 88 cases decided during that period, 33 included authorized returns of 9.90% or higher.

Witness Hevert testified that given DEC's need to access external capital and the weight rating agencies place on the nature of the regulatory environment, he believes it is important to consider the extent to which the jurisdictions that recently have authorized rates of return on equity for electric utilities are viewed as having constructive regulatory environments. Witness Hevert testified that North Carolina generally is considered to have a constructive regulatory environment. He testified that Regulatory Research Associates (RRA), which is a widely referenced source of rate case data, provides an assessment of the extent to which regulatory jurisdictions are constructive from investors' perspectives, or not. As RRA explains, less constructive environments are associated with higher levels of risk:

> RRA maintains three principal rating categories, Above Average, Average, and Below Average, with Above Average indicating a relatively more constructive, lower-risk regulatory environment from an investor viewpoint, and Below Average indicating a less constructive, higher-risk regulatory climate from an investor viewpoint, Within the three principal rating categories, the numbers 1, 2, and 3 indicate relative position. The designation 1 indicates a strong (more constructive) rating; 2, a mid-range rating; and 3, a weaker (less constructive) rating. We endeavor to maintain an approximate equal number of ratings above the average and below the average.[1]

[1] Source: RRA, accessed November 20, 2017.

Within RRA's ranking system, North Carolina is rated "Average/1," which witness Hevert testified falls in the top one-third of the 53 regulatory commissions ranked by RRA. Witness Hevert testified that the stipulated rate of return on equity falls ten to 12 basis points below the mean and median authorized rate of return on equity, respectively, for jurisdictions that are comparable to North Carolina's constructive regulatory environment, and 40 basis points above the median return authorized in less supportive jurisdictions. Taken from that perspective, the stipulated rate of return on equity is a reasonable, if not somewhat conservative, measure of DEC's cost of equity.

AGO witness Woolridge performed a DCF and CAPM for both his and witness Hervert's proxy groups of electric utilities. Witness Woolridge developed his DCF growth rate after reviewing 13 growth rate measures including historic and projected growth rate measures and evaluating growth in dividends, book value, EPS, and growth rate forecasts from Yahoo, Reuters, and Zack's. AGO witness Woolridge testified that it is well known that long-term EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased. AGO witness Woolridge in his supplemental testimony revised his DCF equity cost rate to 8.80% for his proxy group, and 8.80% for the Hevert proxy group.

In witness Woolridge's CAPM, he used for the risk free interest rate the yield on 30-year U.S. Treasury bonds. He used the Value Line Investment Survey betas of 0.70 for his proxy group and 0.70 for witness Hevert's proxy group. Witness Woolridge's market risk premium was 5.5% based in part upon the September 2017 CFO survey conducted by CFO Magazine and Duke University, which included approximately 300 responses, in which the expected market risk premium was 4.32%. He testified thus, that his 5.5% value is a conservatively high estimate of the market risk premium. Witness Woolridge also testified that Duff & Phelps, a well-known valuation and corporate finance advisor that publishes extensively on cost of capital, recommended in 2017 using a 5.5% market risk premium, for the U.S. Witness Woolridge's CAPM equity cost rate was 7.9% for both his and witness Hevert's proxy groups. Witness Woolridge gave primary weight to his DCF results in both his direct and supplemental testimony.

CUCA witness O'Donnell testified that the most useful methodology to produce realistic rate of return on equity results relative to prevailing capital markets, when applied appropriately, is the DCF. To check the reasonableness of his DCF analysis and to gauge the proper rate of return on equity to recommend within the DCF range, he also performed a comparable earnings analysis and CAPM. Witness O'Donnell utilized a proxy group similar to DEC witness Hevert's, except witness O'Donnell eliminated SCANA and Dominion, as these companies are involved in ongoing merger discussions.

Witness O'Donnell calculated his DCF dividend growth rate using the historical retention of earnings, the historical ten-year and five-year compound annual EPS, DPS, and BVPS as reported by Value Line, the Value Line forecasted compound annual rate of change for EPS, DPS, and BVPS, and the forecasted rate of change for EPS that industry analysts supplied to Charles Schwab and Company. Witness O'Donnell's DCF growth rate range was 4.75% to 5.75%, and his calculated DCF range was 8.0% to 9.0%.

In his comparable earning analysis, CUCA witness O'Donnell examined the earned returns on equity for his proxy group and Duke Energy Corporation over the period 2015 through 2022, balancing historical and forecasted returns. The past and forecasted earned returns for the proxy group were 9.25% to 10.25%, and the past and forecasted earned returns for Duke Energy Corporation were 7.5% to 8.5%. His recommended rate of return on equity based upon his comparable earnings analysis ranged from 8.75% to 9.75%.

Witness O'Donnell testified that for his CAPM, he used for the risk-free rate and the current 30-year Treasury bond yields of 2.9%. He expected the current interest rate environment to remain relatively stable for many years to come, citing statements by Federal Reserve Chairperson Janice Yellen. "Yellen Says Forces Holding Down Rates May Be Long Lasting," Barrons, June 16, 2016. The beta used for his proxy group was 0.72 and the beta for Duke Energy Corporation was 0.60. To determine the risk premium in his CAPM, witness O'Donnell used the long-term geometric and arithmetic returns for both large company equities and fixed income Long-Term Government Bonds with the resulting risk premium ranging from 4.60% to 6.20%. He also evaluated the predicted total market returns by a group of market experts, which ranged from 4.5% to 8%. He concluded that his equity risk premium was in the range of 4% to 6% and his CAPM resulted in a return on equity range of 5.06% to 7.52%.

Commercial Group witnesses Chriss and Rosa testified that the average of 97 reported electric utility rate case rates of return on equity authorized by commissions to investor-owned utilities in 2015, 2016 and 2017 was 9.63%. Witnesses Chriss and Rosa further testified that for the group reported by SNL Financial in Commercial Group Exhibit CR-3, the average rate of return on equity for vertically integrated utilities authorized from 2015 through 2017 is 9.78%, which includes the significant outlier 11.95% approved for Alaska Electric Light Power in Docket No. U-16-086, Order dated November 15, 2017. Witnesses Chriss and Rosa testified the average rate of return on equity authorized for vertically integrated utilities was in 2015, 9.75%; in 2016, 9.77%; and in 2017, 9.78%.

Witnesses Chriss and Rosa testified that they know the rate of return on equity decisions of other state regulatory commissions are not binding on the Commission. They testified that each commission considers the specific circumstances in each case in its determination of the proper rate of return on equity. They provided information in their testimony to illustrate a national customer perspective on industry trends in authorized rates of return on equity. These witnesses testified that in addition to using recent authorized rates of return on equity as a general gauge of reasonableness for the various cost-of-equity analyses presented in this case, the Commission should consider how its authorized rate of return on equity impacts North Carolina customers relative to other jurisdictions.

CIGFUR III witness Phillips did not perform cost of capital analyses. He testified that DEC's requested rate of return on equity of 10.75% is excessive and should be rejected. He stated that DEC's current authorized rate of return on equity is 10.2%, which was authorized in the Commission's 2013 DEC Rate Order issued on September 24, 2013. Witness Phillips testified that costs of capital have declined since DEC's last rate case. Every quarter, RRA, an affiliate of SNL Financial, updates its Major Rate Case Decisions report that covers electric and natural gas utility rate case outcomes. Specifically, this report tracks the authorized rates of return on equity resulting from utility rate cases. The most recent report, updated through September 30, 2017, shows that the national average authorized rate of return on equity for electric utilities in the first nine months of this year is 9.63%, nearly 60 basis points below DEC's currently authorized rate of return on equity. Witness Phillips concluded that DEC's current approved rate of return on equity, and definitely DEC's requested rate of return on equity, are significantly above the current market cost of equity. Witness Phillips recommended that the Commission authorize a rate of return on equity that does not exceed the national average of 9.63%.

Tech Customers witness Strunk did not perform rate of return on equity analyses. Instead, his cost of capital testimony focused on criticism of DEC witness Hevert assigning a higher risk factor to DEC than the electric utilities in witness Hevert's proxy group.

Witness Strunk testified that witness Hevert has not done any quantitative analysis to support his testimony that DEC has a comparatively high level of capital expenditures, nor has DEC's witness Hevert done any comparative analysis to support his contention that DEC faces higher risks of environmental regulation than witness Hevert's proxy group. Witness Strunk also testified that DEC witness Hevert's upward risk adjustment for the regulatory environment in which DEC operates is not justified, as North Carolina's regulatory climate is favorable relative to other states.

2. Discussion of Rate of Return Evidence and Conclusions

In a fully contested rate case such as, for example, the 2012 DNCP rate case, there will almost inevitably be conflicting rate of return on equity expert testimony. Even in a partially settled case, the Commission may be faced with conflicting rate of return on equity expert witnesses whose testimony, in accordance with CUCA I and Cooper I, requires detailed consideration and, as necessary, evaluation by the Commission of competing methodologies, opinions, and recommendations. These were the circumstances in DEC's 2011 rate case, Docket No. E-7, Sub 989, which resulted in the Cooper I decision, as well as the 2013 DEP Rate Case. In both of those cases, rate of return on equity expert testimony from CUCA witness O'Donnell provided an alternate rate of return on equity analysis that pegged the utility's cost of capital at an amount lower than the settled rate of return on equity. The Supreme Court in Cooper I faulted the Commission for not making explicit its evaluation of this testimony, and, thus, the Commission in the 2013 DEP Rate Order made an express evaluation of witness O'Donnell's testimony in accordance with the Cooper I decision.

The Commission determines the appropriate rate of return on equity based upon the evidence and particular circumstances of each case. However, the Commission believes that the rate of return on equity trends and decisions by other regulatory authorities deserve some weight, as (1) they provide a check or additional perspective on the case-specific circumstances, and (2) the Company must compete with other regulated utilities in the capital markets, meaning that a rate of return on equity significantly lower than that approved for other utilities of comparable risk would undermine the Company's ability to raise necessary capital, while a rate of return on equity significantly higher than other utilities of comparable risk would result in customers paying more than necessary. In this connection, the analysis performed by Commercial Group witnesses Chriss and Rosa, as modified by witness Hevert, is instructive. Witnesses Chriss and Rosa noted that according to data from SNL Financial for 2015 through 2017, authorized rates of return on equity across the country for vertically-integrated electric utilities have been in the range of 9.10% to 10.55%, excluding the Alaska Electric Light and Power significant outlier at 11.95%. Witnesses Chriss and Rosa calculated the mean authorized rate of return on equity for vertically-integrated utilities like DEC to be 9.78%. Witness Hevert, in commenting upon and evaluating their testimony in his Rebuttal Testimony, refined their analysis and presented his findings in Exhibit RBH-R28 to add in jurisdictional rankings. Doing so results in a rate of return on equity range from 9.80% to 10.55%, with a median of 10.0%. Tr. Vol. 4, p. 393. The Stipulation rate of return on equity is, of course, within that range, and actually below the median of that range. As witness Hevert's settlement testimony notes, "since 2014, the average authorized Return on Equity for vertically integrated electric utilities has been 9.81%, only nine basis points from the Stipulation rate of return on equity. Among jurisdictions that, like North Carolina, are seen as having constructive regulatory environments, the average authorized ROE [rate of return on equity] was 10.02%, 12 basis points above the 9.90% Stipulation ROE [rate of return on equity]." Id. at 418. Accordingly, the evidence presented concerning other authorized rates of return on equity, when put into proper context, lends substantial support to the stipulated 9.9% rate of return on equity level.

Finally, as the Supreme Court made clear in CUCA I and CUCA II, the Commission should give consideration to the non-unanimous Stipulation as relevant evidence, along with all evidence presented by other parties, in determining whether the Stipulation's provisions should be accepted. In this case, insofar as expert rate of return on equity testimony is concerned, no expert witness presented credible or substantial evidence that the stipulated 9.9% rate of return on equity is not just or reasonable to all parties. Both witnesses Hevert and Parcell supported DEC's required rate of return on equity at that level, in the context of the Stipulation as a whole, and witness Hevert was subjected to extensive cross-examination. Thus, the Commission finds and concludes that the Stipulation, along with the expert testimony of witnesses Hevert (risk premium analysis), O'Donnell (comparable earnings), and Parcell (comparable earnings), are credible and substantial evidence of the appropriate rate of return on equity and are entitled to substantial weight in the Commission's determination of this issue.

3. Evidence of Impact of Changing Economic Conditions on Customers

As noted above, utility rates must be set within the constitutional constraints made clear by the United States Supreme Court in Bluefield and Hope. To fix rates that do not allow a utility to recover its costs, including the cost of equity capital, would be an unconstitutional taking. In assessing the impact of changing economic conditions on customers in setting a return on equity, the Commission must nonetheless provide the public utility with the opportunity, by sound management, to (1) produce a fair profit for its shareholders, in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital. State ex rel. Utils. Comm'n v. General Telephone Co. of the Southeast, 281 N.C. 318, 370, 189 S.E.2d 705 (1972). As the Supreme Court held in that case, these factors constitute "the test of a fair rate of return declared" in Bluefield and Hope. Id.

a. Discussion and Conclusions Regarding Evidence Introduced During the Expert Witness Hearing

In this case, all parties had the opportunity to present the Commission with evidence concerning changing economic conditions as they affect customers. The testimony of witnesses Hevert and Parcell, which the Commission finds entitled to substantial weight, addresses changing economic conditions at some length. Witness Hevert provided detailed data concerning changing economic conditions in North Carolina as well as nationally, and concluded that the North Carolina-specific conditions are "highly correlated" with conditions in the broader nationwide economy. As such, witness Hevert testified that changing economic conditions, both nationally and specific to North Carolina, are reflected in his rate of return on equity estimates.

DEC witness Hevert testified extensively on economic conditions in North Carolina. He testified that unemployment has fallen substantially in North Carolina and the U.S. since late 2009 and early 2010, when the rates peaked at 10.00% and 11.30%, respectively. By May 2017, the unemployment rate had fallen to one-half of those peak levels: 4.30% nationally, and 4.50% in North Carolina. Since DEC's last rate filing in 2013, the unemployment rate in North Carolina has fallen from 8.70% to 4.50%.

Witness Hevert testified that with respect to GDP, there also has been a relatively strong correlation between North Carolina and the national economy (approximately 69.00%). Since the financial crisis, the national rate of growth at times (during portions of 2010 and 2012) outpaced North Carolina. Since the third quarter of 2015, however, North Carolina has consistently exceeded the national growth rate. He testified that as to median household income, the correlation between North Carolina and the U.S. is relatively strong (nearly 86.18% from 2005 through 2015). Since 2009 (that is, the years subsequent to the financial crisis), median household income in North Carolina has grown at a faster annual rate than the national median income.

Witness Hevert testified as to the seasonally unadjusted unemployment rates in the counties served by DEC. At the unemployment peak, which occurred in late 2009 into early 2010, the unemployment rate in those counties reached 13.80% (1.80 percentage points higher than the State-wide average); by April 2017 it had fallen to approximately 4.15% (0.15 percentage points lower than the State-wide average). Since DEC's last rate filing in 2013, these counties' unemployment rates have fallen by over 5.70 percentage points.

Witness Hevert testified that it is his opinion that, based on the indicators discussed above, North Carolina and the counties contained within DEC's service area continue to steadily emerge from the economic downturn that prevailed during DEC's previous rate case, and that they have experienced significant economic improvement during the last several years. He testified that this improvement is projected to continue.

Public Staff witness Parcell testified that he is aware of no clear numerical basis for quantifying the impact of changing economic conditions on customers in determining an appropriate rate of return on equity in setting rates for a public utility. He testified that the impact of changing economic conditions nationwide is inherent in the methods and data used in his study to determine the cost of equity for utilities that are comparable in risk to DEC.

Witness Parcell testified that DEC provides service in 44 counties, and that the 11 counties North Carolina Department of Commerce classified as Tier 1 counties had an August 2017 not-seasonally-adjusted combined unemployment rate of 4.5%, with a combined total of 6,177 persons unemployed, and a combined total labor force of 136,989 persons. The 21 Tier 2 counties had an August 2017 not-seasonally-adjusted combined unemployment rate of 4.6%, with a combined total of 54,552 persons unemployed and a combined total labor force of 1.193 million persons. The 12 Tier 3 counties had an August 2017 not-seasonally-adjusted combined unemployment rate of 4.0%, with a combined total of 80,066 persons unemployed, with a combined total labor force of 2.009 million persons. The August 2017 not-seasonally-adjusted North Carolina unemployment rate was 4.5%. He testified that all 44 counties experienced a drop in their not-seasonally-adjusted unemployment rates between August 2016 and August 2017, averaging a 0.8% decrease compared to the statewide decrease of 0.8%. Witness Parcell further testified that the North Carolina Department of Commerce in its December 2017 NC Today stated that North Carolina industry employment had an increase of 71,500 over the year, an increase in real taxable retail sales of $401.0 million over the year, an increase in residential building permits of 16.9% over the year, and an increase in job postings of 12.2% over the year. Witness Parcell testified that there are reasons to believe that the economic conditions in the nation and in North Carolina will continue to improve, which should provide a benefit for many DEC customers. He concluded by stating that the Commission's duty to set rates as low as reasonably possible consistent with constitutional requirements without jeopardizing adequate and reliable service is the same regardless of the customer's ability to pay.

b. Evidence Introduced During Public Witness Hearings and Further Conclusions

The Commission's review also includes consideration of the evidence presented, primarily by way of non-expert witness testimony, at three evening hearings held throughout DEC's North Carolina service territory to receive public witness testimony. The public witness hearings held in this proceeding afforded 75 public witnesses, most of whom are customers of DEC, the opportunity to be heard regarding their respective positions on DEC's application for a general rate increase. The testimony presented at the non-expert witness hearings illustrates in detail the difficult economic conditions facing many DEC customers, and the witnesses' general objection to DEC recovering costs related to coal ash cleanup. More than 20 witnesses testified that the rate increase was not affordable for many customers, including those on fixed incomes, the elderly, persons with disabilities, the under- and unemployed, and the poor. Notably, a number of customers also expressed the view that the Company should be required to revise its current grid modernization plans in favor of increased energy efficiency and renewable energy resources initiatives. A representative sample of the public witness testimony received is summarized below.

Summary of Testimony Received in Franklin

At the hearing in Franklin, witnesses Watters, Bugash, Friedman, and Corbin acknowledged that DEC provides reliable electric service, and is responsive when power outages occur, particularly those that are weather-related or caused by natural disasters. Notwithstanding their general satisfaction with electric service reliability, neither witness Watters nor witness Bugash supports DEC's requested rate increase. Witness Lawley, on the other hand, testified that DEC does not provide adequate or reliable electric service, particularly to those customers who live in the mountains, and that minor inclement weather can result in power outages that take DEC days or weeks to resolve. Witness Lawley testified that the power has gone out at her residence nearly 100 times during a two-year period. Witness Lawley testified that DEC claimed that the outages were caused by squirrels, but she opined that the outages actually were the result of a defective piece of equipment that DEC failed to timely fix. Witness Boyd testified that he also does not receive reliable electric service from DEC and opined that this is in part due to DEC's failure to adequately manage vegetation in the area. Witness Crownover testified that she was overcharged by DEC for many years due to having been listed incorrectly by DEC as a recipient of natural gas utility service. Chairman Finley directed DEC to investigate the service and billing complaints of these witnesses, and to report to the Commission the results thereof.

Witness Watters testified that it is unfair that the lowest energy users are charged a higher variable rate for energy than those customers who consume larger amounts of energy. Witnesses Watters, Friedman, and Smith testified that DEC should be doing more to transition from coal and natural gas to renewable energy, including solar and wind power.

Witnesses Sparks, Erickson, Horton, Crawford, Boyd, and Smith oppose a rate increase because, in their opinion, DEC's financial position is healthy enough such that a rate increase is unnecessary. Witnesses Sparks, Horton, Lawley, Zwinak, Wilde, Smith, and Corbin testified that customers living on a fixed or low income, including senior citizens and those living with disabilities, cannot afford a rate increase. Witness Wilde testified that "even [] a one cent increase in electric" costs would break the already stretched fixed-incomes of the elderly. Tr. Vol. 1, p. 64. After explaining that a number of counties across North Carolina face significant economic distress, witness Smith, a former Board Chair of the Jackson-Macon Conservation Alliance, expressed concern that the suggested rate hike would be "shared equally among all counties, despite enormous economic disparities." Id. at 66. Any rate increase, Mr. Smith concluded, would "translate to real sacrifices for working families" in those counties. Id. at 68. Witness Smith further testified that a rate increase would discourage energy efficiency and conservation measures.

Witnesses Sparks, Erickson, Crawford, Bugash, Friedman, Lawley, Zwinak, Crownover, Wilde, and Smith testified that DEC's shareholders, and not its ratepayers, should be required to bear the costs of DEC's mismanagement in failing to properly handle and dispose of coal ash. Witnesses Lawley and Smith testified that those customers directly affected by DEC's coal ash mismanagement have been drinking bottled water for a long time and have not received any reimbursement for their losses, but still would be subject to paying for a rate increase to remedy DEC's environmental non-compliance. Witnesses Friedman and Lawley also oppose the cost recovery for the canceled Lee nuclear plant.

Witness Lawley testified that, in his opinion, the infrastructure of DEC's electric grid is inadequate, and that DEC is not doing enough to improve redundancy. Witness Lawley also, however, opposes DEC's proposed grid modernization initiative because of its vagueness and cost.

In its March 29, 2018 Customer Inquiry Follow-up Report, DEC stated that it investigated and resolved the service complaints of witnesses Lawley and Crownover. DEC's March 29, 2018 Customer Inquiry Follow-up Report did not address the complaint of witness Boyd, however.

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Summary of Testimony Received in Greensboro

Witness Goodson, the Executive Director for the North Carolina Community Action Association, thanked DEC for its current programs designed to aid low-income individuals and requested that the Company increase its spending on such programs, including its energy efficiency weatherization program.

Witnesses Goodson, Wright, Bass, Merrell, Concepcion, Preschle, Phillips, Stevenson, Diaz-Reyes, Smith, Ruder, Ellison, Kriegsman, Freeman, Hutchby, and Longstreet testified that many ratepayers cannot afford a rate increase, particularly the under- and unemployed and those living on low or fixed incomes, including students, persons with disabilities, the elderly, and the poor. Witnesses Wright and Diaz-Reyes also testified that those who would have a difficult time paying for a rate increase also are the customers likely to use more energy due to living in older, more poorly insulated homes. Witness Sevier, a member of AARP, testified that homeless students, in addition to Social Security recipients, would not be able to pay for a rate increase. Witness Petty testified that the rate increase would disproportionately affect the budgets of low income individuals more so than those with disposable income. Witness Concepcion complained that her electric bill was unreasonably high for January 2018.

Witnesses Carter, Wright, Phillips, Stevenson, and Hutchby testified that, in their opinion, DEC's financial position is healthy enough such that a rate increase is unnecessary. Witness Stevenson testified that the recent federal tax cut should obviate the need for some or all of DEC's requested rate increase.

Witnesses A. Martin, R. Martin, Graham, Bass, Merrell, Concepcion, Tuch, Preschle, Lange, Phillips, Bishop, Diaz-Reyes, Smith, Robins, Fansler, Kriegsman, Motsinger, and Hutchby testified that DEC's shareholders, and not its ratepayers, should be required to bear the costs of DEC's mismanagement in failing to properly handle and dispose of coal ash. Witness Graham testified that she lives near a DEC coal ash pit and, as a result, has had to live on bottled water for over 1,000 days. Witnesses Graham, Fansler, and Hutchby testified that it is wrong to ask those who have been directly harmed by DEC's coal ash management practices to also pay more for their electric service.

Witnesses A. Martin and Tuch testified in support of DEC's efforts toward increasing renewable energy and contend they would be willing to pay a premium for their electric service to support those endeavors. Witness Tuch, the Chair of the North Carolina Climate Solutions Coalition, testified that Duke should be planning to transition to 100 percent cleaner, renewable energy by 2050. Witnesses Preschle and Diaz-Reyes testified that DEC should be more focused on cost-effective clean energy and sustainability practices, including offshore wind energy. Witness Freeman testified that the proposed increase to the basic customer charge is unfair to low-income customers and those who use the least amount of energy, including those customers who employ energy efficiency or have invested in renewable energy measures.

Witnesses Bishop and Fansler oppose the cost recovery for the canceled Lee nuclear plant. Witnesses Stevenson and Kriegsman testified in opposition to DEC's proposed grid modernization initiative, stating that the program lacks transparency and "detailed insight, given the recent failed nuclear ventures, also because the grid mods are future investment and the other issues are past failures." Tr. Vol. 2, p. 64. Witness Ruder opposes cost recovery for AMI smart meters and opines that they were "a very bad investment," about which customers have had a number of complaints. Id. at 71.

In its March 29, 2018 Customer Inquiry Follow-up Report, DEC stated that it investigated and resolved the billing complaint of witness Concepcion. DEC's March 29, 2018 Customer Inquiry Follow-up Report did not address the complaint of witness Graham.

Summary of Testimony Received in Charlotte

Witnesses Kasher, Taylor, English, Nicholson, Satterfield, Brown, Hollis, McLaney, Moore, Henry, Sprouse, Blotnick, Copulsky, Jones, Segal, Lauer, Eddleman, and Mitchell testified that DEC's shareholders, and not its ratepayers, should be required to bear the costs of DEC's mismanagement in failing to properly handle and dispose of coal ash. Witnesses English, Nicholson, and Satterfield testified that allowing DEC to charge its ratepayers for coal ash cleanup would set problematic precedent in the event of future environmental issues. Witnesses Brown and Lauer testified to the direct impacts that DEC's coal ash mismanagements have had on their lives, including their water supply, and opined that it is wrong to ask those who have been directly harmed by DEC's coal ash management practices to pay more for their electric service. Witness Eddleman testified that DEC has "always refused to line their coal ash pits." Tr. Vol. 3, p. 115.

Witnesses Nicholson, Dawson, Segal, and Eddleman testified that DEC's financial position is healthy enough such that a rate increase is unnecessary. Witnesses Kasher and Sparrow testified that the recent federal tax cut should obviate the need for some or all of DEC's requested rate increase.

Witnesses Kasher, English, Kneidel, Crawford, Blotnick, King, Houlihan, Jones, Eddleman, and Adams testified that DEC should be more focused on cleaner, cheaper renewable energy, including wind and solar. Witnesses Kneidel, Moore, Henry, King, Houlihan, Copulsky, Rose, and Adams testified that DEC's proposed grid modernization initiative is vague and will not do enough to connect more, clean, renewable energy to the grid. Witnesses Moore, Henry, Blotnick, King, and Houlihan testified that DEC has not justified its planned grid modernization spending, particularly since it will not help to lower bills or conserve electricity and does not involve actual modernization of the grid. Witness Henry also testified in opposition to DEC's proposed cost allocation for its grid modernization spending.

Witnesses Baker, Williams, Taylor, Nicholson, Hollis, Johnson, Dawson, Jones, Cano, Segal, and Mitchell testified that many ratepayers cannot afford a rate increase, particularly the under- and unemployed and those on low or fixed incomes, including the elderly, persons with disabilities, and the poor. Witnesses Satterfield, Hollis, Blotnick, and Eddleman oppose DEC's proposed basic customer charge increase because it disproportionately affects low-income individuals and those that use the least amount of energy or practice energy conservation measures.

Witnesses English, Nicholson, Satterfield, Henry, Sprouse, Copulsky, Eddleman, and Adams testified in opposition to cost recovery for the canceled Lee nuclear plant.

In its March 29, 2018 Customer Inquiry Follow-up Report, DEC stated that it investigated the complaint of witness Lauer and determined that the location at issue is served by Rutherford Electric Membership Corporation, not DEC. DEC's March 29, 2018 Customer Inquiry Follow-up Report did not address the complaint of witness Brown.

The Commission accepts as credible and probative the testimony of public witnesses, illustrating the economic strain felt by many North Carolina citizens, while also reflecting their interests in energy efficiency and renewable energy. The Commission also accepts as credible and probative the testimony of witness Hevert indicating that economic conditions in North Carolina are highly correlated with national conditions, and that such conditions are reflected in his econometric analyses and resulting rate of return on equity recommendations.

c. Commission's Decision Setting Rate of Return and Approving Rate Adjustment Takes Into Account and Ameliorates the Impact of Current Economic Conditions on Customers

As noted above, the Commission's duty under N.C. Gen. Stat. § 62-133 is to set rates as low as reasonably possible without impairing the Company's ability to raise the capital needed to provide reliable electric service and recover its cost of providing service. The Commission is especially mindful of this duty in light of the evidence in this case concerning the impact of current economic conditions on customers.

Chapter 62 in general, and N.C. Gen. Stat. § 62-133 in particular, set forth an elaborate formula the Commission must employ in establishing rates. The rate of return on cost of property element of the formula in N.C. Gen. Stat. § 62-133(b)(4) is a significant, but not independent one. Each element of the formula must be analyzed to determine the utility's cost of service and revenue requirement. The Commission must make many subjective decisions with respect to each element in the formula in establishing the rates it approves in a general rate case. The Commission must approve accounting and pro forma adjustments to comply with N.C. Gen. Stat. § 62-133(b)(3). The Commission must approve depreciation rates pursuant to N.C. Gen. Stat. § 62-133(b)(1). The decisions the Commission makes in each of these subjective areas have multiple and varied impacts on the decisions it makes elsewhere in establishing rates, such as its decision on rate of return on equity.

Economic conditions existing during the test year, at the time of the public hearings, and at the date of this Order affect not only the ability of DEC's customers to pay electric rates, but also the ability of DEC to earn the authorized rate of return during the period rates will be in effect. Pursuant to N.C. Gen. Stat. § 62-133, rates in North Carolina are set based on a modified historic test period.[1] A component of cost of service as important as return on investment is test year revenues.[2] 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.

[1] N.C. Gen. Stat. § 62-133(c)

[2] N.C. Gen. Stat. § 62-133(b)(3).

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DEC is in a significant construction mode – adding new gas-fired plants, retrofitting nuclear units, and investing in transmission and distribution facilities. Much of this investment is responsive to environmental regulatory requirements. New gas units will replace older, less efficient, higher polluting coal units. These units do little to meet new growth.

When costs and expenses grow at a faster pace than revenues during the period when rates will be in effect, the utility will experience a decline in its realized rate of return on investment to a level below its authorized rate of return. Differences exist between the authorized return and the earned, or realized, return. Components of the cost of service must be paid from the rates the utility charges before the equity investors are paid their return on equity. Operating and administrative expenses must be paid, depreciation must be funded, taxes must be paid, and the utility must pay interest on the debt it incurs. To the extent revenues are insufficient to cover the entire cost of service, the shortfall reduces the return to the equity investor, last in line to be paid. When this occurs, the utility's realized, or earned, return is less than the authorized return.

This phenomenon, caused by incurrence of higher costs prior to the implementation of new rates to recover those higher costs, is commonly referred to as regulatory lag. Just as the Commission confronts constitutional and statutory restrictions in making discrete decrements to rate of return on equity to mitigate the impact of rates on consumers, it also confronts statutory constraints on its ability to adjust test year revenues to mitigate for regulatory lag. The Commission, in its expert experience and judgment and based on evidence in the record, is aware of the effects of regulatory lag in the existing economic environment. However, just as the Commission is constrained to address difficult economic times on customers' ability to pay for service by establishing a lower rate of return on equity in isolation from the many subjective determinations that must be made in a general rate case, it likewise does not address the effect of regulatory lag on the Company by establishing a higher rate of return on equity. Instead, in setting the rate of return, the Commission considers both of these negative impacts in its ultimate decision fixing DEC's rates. The Commission keeps all factors affected by current economic conditions in mind in the many subjective decisions it makes in establishing rates. In doing so in the case at hand, the Commission has accepted the stipulated 9.9% rate of return on equity in the context of weighing and balancing numerous factors and making many subjective decisions. When these decisions are viewed as a whole, including the decision to establish the rate of return on equity at 9.9%, the Commission's overall decision fixing rates in this general rate case results in lower rates to consumers in the existing economic environment.

Consumers pay rates, a charge in cents per kWh or per kW for the electricity they consume. Investors are compensated by earning a return on the capital they invest in the business. Consumers do not pay a rate of return on equity. Investors are paid in dollars. In this case, DEC filed rate schedules that would have produced additional annual revenues of $612,647,000. This is the amount ratepayers would pay. These additional revenues, pursuant to the Application and according to DEC's initial calculations, would have produced $5,340,499,000 in total electric operating revenues and $1,093,549,000 in return on investment. Of this amount, $786,153,000 was the return that would have been paid to equity investors, the "return on equity." According to the Application, the "rate of return on equity" financed portion of the investment (as distinguished from the "return on equity") would have been 10.75%.

All of the scores of adjustments the Commission approves reduce the revenues to be recovered from ratepayers and the return to be paid to equity investors. Some adjustments reduce the authorized rate of return on investment financed by equity investors. The noted adjustments are made solely to reduce rates and provide rate stability to consumers (and return to equity investors) to recognize the difficulty for consumers to pay in the current economic environment. While the equity investor's cost was calculated by resort to a rate of return on equity of 9.9% instead of 10.75%, this is only one approved adjustment that reduced ratepayer responsibility and equity investor reward. Many other adjustments reduced the dollars the investors actually have the opportunity to receive. Therefore, nearly all of these other adjustments reduce ratepayer responsibility and equity investor returns in compliance with the Commission's responsibility to establish rates as low as reasonably permissible without transgressing constitutional constraints.

For example, to the extent the Commission makes downward adjustments to rate base, or disallows test year expenses, or increases test year revenues, or reduces the equity capital structure component, the Commission reduces the rates consumers pay during the future period when rates will be in effect. Because the utility's investors' compensation for the provision of service to consumers takes the form of return on investment, downward adjustments to rate base or disallowances of test year expenses or increases to test year revenues, or reduction in the equity capital structure component, reduce investors' return on investment irrespective of its determination of rate of return on equity.

The rate base, expenses, and revenue examples listed above are instances where the Commission makes decisions in each general rate case, including the present case, that influence the Commission's determination on rate of return on equity and cost of service and the revenue requirement. The Commission always endeavors to comply with the North Carolina Supreme Court's requirements that it "fix rates as low as may be reasonably consistent" with U.S. Constitutional requirements irrespective of economic conditions in which ratepayers find themselves. While compliance with these requirements may have been implicit and, the Commission reasonably assumed, self-evident as shown above, the Commission makes them explicit in this case to comply with the Supreme Court requirements of Cooper I.

Based on the changing economic conditions and their effects on DEC's customers, the Commission recognizes the financial difficulty that adjustments in DEC's rates may create for some of DEC's customers, especially low-income customers. As shown by the evidence, relatively small changes in the rate of return on equity have a substantial impact on a utility's base rates. Therefore, the Commission has carefully considered the changing economic conditions and their effects on DEC's customers in reaching its decision regarding DEC's approved rate of return on equity. The Commission also recognizes that the Company is investing significant sums in generation, transmission, and distribution improvements to serve its customers, thus requiring the Company to maintain its creditworthiness in order to compete for large sums of capital on reasonable terms. The Commission must weigh the impact of changing economic conditions on DEC's customers against the benefits that those customers derive from the Company's ability to provide safe, adequate, and reliable electric service. Safe, adequate, and reliable electric service is essential to the well-being of the people, businesses, institutions, and economy of North Carolina.

The Commission finds and concludes that these investments by the Company provide significant benefits to all of DEC's customers. The Commission concludes that the rate of return on equity approved by the Commission in this proceeding appropriately balances the benefits received by DEC's customers from DEC's provision of safe, adequate, and reliable electric service in support of the well-being of the people, businesses, institutions, and economy of North Carolina with the difficulties that some of DEC's customers will experience in paying DEC's adjusted rates.

Finally, the Commission gives significant weight to the Stipulation and the benefits that it provides to DEC's customers, which the Commission is obliged to consider as an independent piece of evidence under the Supreme Court's holdings in CUCA I and CUCA II.

The Commission in every case seeks to comply with the N.C. Supreme Court mandate that the Commission establish rates as low as possible within Constitutional limits. The scores of adjustments the Commission approves in this case comply with that mandate. Nearly all of them reduced the requested return on equity and benefit consumers' ability to pay their bills in this economic environment.

In this case, DEC originally requested a retail revenue increase of $611 million, or a 12.8% increase in annual revenues. The Commission has examined the Company's Application and supporting testimony and exhibits and Form E-1 filings seeking to justify this increase. The Public Staff and DEC reached a Stipulation that resulted in reducing the retail revenue increase sought by the Company by approximately $159 million. The Public Staff represents the using and consuming public, including those having difficulty paying their bills. The Public Staff representatives attended all of the hearings held across the State to receive customers' testimony. The Public Staff has a staff of expert engineers, economists, and accountants who investigate and audit the Company's filings. The Public Staff must recommend rates consumers should pay and the return on investment equity investors should receive. The Public Staff considers all factors included in cost of service. In recent years, the Public Staff and the utilities have entered into settlements resolving the issues so as to avoid at least part of the substantial rate case expense customers otherwise would pay. This process is favored by financial analysts and rating agencies because it reduces delay and enhances predictability, thereby creating a constructive, credit supportive, regulatory environment ultimately reflected favorably in investors' required cost of capital. Intervenors who generally represent narrow segments or classes of ratepayers seldom enter into these settlements, though often times they do not oppose them.

As with all settlement agreements, each party to the Stipulation gained some benefits that it deemed important and gave some concessions for those benefits. Based on DEC's Application and pre-filed testimony, it is apparent that the Stipulation ties the 9.9% rate of return on equity to substantial concessions the Company made.

Summary and Conclusions on the Rate of Return on Equity

The Commission has carefully evaluated the return on equity testimonies of DEC witness Hevert, Public Staff witness Parcell, AGO witness Woolridge, CUCA witness O'Donnell, Commercial Group witnesses Chriss and Rosa, Tech Group witness Strunk, and CIGFUR III witness Phillips. The Commission finds that the comparable earnings analysis testimony of Public

Staff witness Parcell, the risk premium analysis testimony of DEC witness Hevert, the comparable earnings testimony of CUCA witness O'Donnell, and the Stipulation are credible, probative, and are entitled to substantial weight.

Public Staff witness Parcell conducted a comparable earnings analysis using both his and witness Hevert's proxy groups of electric utilities. His comparable earnings recommended rate of return on equity range was 9.0% to 10.0%. The Commission approved rate of return on equity of 9.9% is in the upper portion of his range. As testified by witness Parcell, the comparable earnings analysis is based on the opportunity cost principle and is consistent with and derived from the Bluefield and Hope decisions of the U.S. Supreme Court, which are recognized as the primary standards for the establishment of a fair rate of return for a regulated public utility. The comparable earnings method is also consistent with the concept of rate base regulation for utilities, which employs the book value of both rate base and the capital financing rate base. Witness Parcell testified that his comparable earnings analyses considers the recent historic and prospective rates of return on equity for the groups of proxy utilities companies utilized by himself and DEC witness Hevert. He testified that his comparable earnings analyses reflect the actual rates of return on equity of the proxy companies, as well as the market-to-book ratios of these companies.

DEC competes against the Hevert and Parcell electric proxy group electric companies and other electric utilities for investments in equity capital. Investors have choices as to which electric utilities, or other companies, in which to invest. A Commission approved rate of return on equity for DEC below the earned rates of return on equity of other electric utilities could provide one basis for investors to invest in the equity of electric utilities other than DEC.

DEC witness Hevert's risk premium analysis is credible, probative, and entitled to substantial weight. His risk premium was calculated as the difference between the authorized rate of return on equity and the then-prevailing level of long-term 30-year Treasury yield. He then gathered data for 1,508 electric utility rate proceedings between January 1980 and March 31, 2017. The Commission approved rate of return on equity of 9.9% is approximately ten basis points below witness Hevert's risk premium's implied rate of return on equity range of 9.97% to 10.33%.

The Commission also concludes that the comparable earnings analysis by CUCA witness O'Donnell is credible, probative, and entitled to substantial weight. Witness O'Donnell testified that the comparable earnings for his and witness Hevert's proxy group of electric utilities produced earned returns of 9.25% to 10.25% over the period 2015 through 2022, balancing historical and forecasted returns. The Commission-approved 9.9% rate of return on equity is well within that range.

In its post-hearing brief, the AGO argues that the rate of return in the Settlement unnecessarily adds well over $100 million to DEC's annual revenue requirement, compared to an 8.75% rate of return on equity and a capital structure containing 50% equity and 50% debt. The AGO states that such an excessive return sends dollars out of North Carolina to DEC's shareholders – wherever in the world they are – and those dollars would be better spent in our local communities. In addition, the AGO believes that if DEC is allowed to recover coal ash costs from ratepayers drawing on the Commission's discretionary authority for the benefit of DEC's investors, the Commission should also exercise its discretion on behalf of consumers and establish a substantial reduction in the rate of return. The AGO notes that its witness Woolridge initially recommended a rate of return on equity of 8.4% based on market conditions when he prepared his testimony in January of 2018, but increased his recommendation to 8.75% when he updated his analyses two months later in March.

The AGO states that witness Woolridge's recommendation was based on two well-established models, the DCF and CAPM. The AGO argues that the comparable earnings model, which was used by Public Staff witness Parcell and CUCA witness O'Donnell, is not a recognized approach to estimating the cost of equity and that the "Risk Bond Yield Premium" was flawed for the reasons described in the testimony of its witness Woolridge.

The AGO states that ratepayers need a break, particularly if the Commission intends to allow DEC to recover coal ash closure costs.

In its post-hearing brief, the Commercial Group argues that the Settlement rate of return on equity of 9.90% should serve as an upper limit, but only if the Grid Rider mechanism is not approved. If the Grid Rider is adopted, the Commercial Group believes that DEC's rate of return on equity should be set below 9.90%.

CUCA, in its post-hearing brief, recommends that the Commission should not approve the Settlement, including cost of capital issues, between DEC and the Public Staff. CUCA states that the witnesses of the Public Staff, the AGO, CUCA and the Tech Customers have a "clustered" set of rate of return on equity recommendations that center around 9.0%, while DEC's witness recommends 10.75%. CUCA then argues that the 9.9% rate of return on equity in the Stipulation should be rejected, among other reasons, for the fact that it gives equal weight to the recommendations of the Public Staff and DEC witnesses only and gives zero weight to the recommendations of the other three expert witnesses. Further, to the extent that the Commission allows what DEC has requested with regard to coal ash cost recovery, the federal income tax reduction, Power Forward, and the Grid Rider, each of these things makes DEC a significantly less risky investment and, when risks go down, the rate of equity should go down accordingly. CUCA requests that the Commission refuse to accept 9.9% rate of return in the Stipulation and fix a rate of return for DEC that is compatible with the consensus results of the non-DEC witnesses.

In its post-hearing brief, Tech Customers state that while the Stipulation is material evidence entitled to appropriate weight in determining DEC's rate of return on equity and other rate of return inputs, the return approved by the Commission must be justified by substantial, competent evidence in the record as a whole. Tech Customers acknowledge that the 9.9% rate of return agreed to in the Stipulation is comfortably within the range advocated by the parties to the Stipulation, but argues that the Stipulation, standing alone, cannot support the 9.9% recommended return on equity, particularly when the rate at one side of the range lacks any indicia of a rational basis.

Tech Customers state that a utility advocating a rate of return on equity figure that substantially exceeds the output of widely-recognized empirical models and that exceeds recently authorized returns must justify that proposed upward adjustment with a quantitative analysis that shows the applicants risk profile to be materially higher than that of the proxy group. Tech Customers state that its witness Strunk outlined several empirical measures of risk in his testimony and the associated exhibits and none suggests DEC presents a higher risk profile than the proxy group companies. Given the results of the empirical models and the lack of objective evidence by DEC that it presents a higher risk profile than the proxy group warranting an upward departure from these measures, a rate of return on equity of 9.9% is unreasonably high. Accordingly, Tech Customers contend that the evidence presented concerning other authorized rates of return on equity, when put into proper context, lends substantial support to an authorized rate of return on equity of 9.70%.

The Commission has carefully evaluated the DCF analysis recommendations of witnesses Parcell, Hevert, Woolridge, Strunk, and O'Donnell, and the Commission gives limited weight to these analyses. As shown on Commercial Group's Exhibit CR-3, the lowest Commission-approved rate of return on equity for a vertically-integrated electric company for the period of 2015 through 2017 was 9.1%. Witness Parcell's specific DCF result was 8.7%, as stated in AGO witness Woolridge's Supplemental Exhibit JRW-2, p.1, his DCF recommendation was 8.80%, and the mid-point of witness O'Donnell's DCF was 8.5%. The average of Hevert's constant growth DCF means, as stated in Table 11 of his rebuttal testimony, was 8.45%, and the mid-point of the range of witness Hevert's Multi-Stage DCF analysis was 8.78%. The Commission considers all of these DCF results to be outliers, being well below the lowest vertically-integrated authorized rate of return on equity of 9.1%. The Commission determines that all of these DCF analyses in the current market produce unrealistically low results.

The Commission gives no weight to any of the witnesses' CAPM analyses. The analyses of witness Parcell with a mid-point of 6.5% is unrealistically low, and witness Parcell agreed as much in his testimony. The CAPM analysis of witness O'Donnell resulted in a CAPM rate of return on equity mid-point of 6.29%, which is an outlier well below the 9.1% previously discussed. Witness Woolridge's CAPM weighted median rate of return on equity of 7.90% is also an outlier and unrealistically low. DEC Witness Hevert's CAPM range of 9.18% to 11.88% is also an outlier and upwardly biased due to witness Hevert's risk premium component of his CAPM using a constant growth DCF for the S&P 500 companies solely using analysts projected EPS forecasts as the growth component. Witness Hevert's DCF dividend growth, component based solely on analysts' EPS growth projections, without consideration of any historical results, is upwardly biased and unreliable.

The rate of return on equity testimonies of Commercial Group witnesses Chriss and Rosa focused on the commission-approved rates of return on equity authorized for vertically-integrated electric utilities in 2015, 2016, and 2017 listed in Commercial Group Exhibit CR-3. The Commission gives weight to this testimony only as a check on the Commission's approved 9.9% rate of return on equity and to evaluate outlier rate of return on equity recommendations. CIGFUR III witness Phillips' testimony focused on the RRA report Major Rate Case Decisions, which showed a 9.61% average authorized rate of return on equity for electric utilities including both vertically-integrated electric utilities and distribution-only electric utilities. Since DEC is a vertically-integrated electric utility, the Commission gives witness Phillips' rate of return on equity testimony limited weight regarding authorized rates of return on equity for distribution-only electric utilities. Rather, as stated in Commercial Group Exhibit CR-3, recently authorized rates of return on equity for vertically-integrated electric utilities since 2015 average 9.78%, and in jurisdictions with RRA rated Average 1 constructive regulatory environments, being the same A1 rating as North Carolina, as shown in Hevert Exhibit RBH-R27 for the 16 decisions for vertically integrated electric utilities in the years 2015, 2016, and 2017, the average approved rate of return on equity was 9.93%. These two vertically-integrated electric utilities averages serve as a better check.

The 9.9% rate of return on equity approved in this proceeding for DEC is also consistent with the 9.9% rate of return on equity that the Commission approved for DNCP in the 2016 Rate Order and DEP in the 2018 Rate Order.

The Commission notes further that its approval of a rate of return on equity at the level of 9.9% – or for that matter, at any level – is not a guarantee to the Company that it will earn a rate of return on equity at that level. Rather, as North Carolina law requires, setting the rate of return on equity at this level merely affords DEC the opportunity to achieve such a return. The Commission finds and concludes, based upon all the evidence presented, that the rate of return on equity provided for herein will indeed afford the Company the opportunity to earn a reasonable and sufficient return for its shareholders, while at the same time producing rates that are just and reasonable to its customers.

Capital Structure

DEC originally proposed using a capital structure of 53% members' equity and 47% long-term debt. Tr. Vol. 4, p. 43. The Stipulation provides for a capital structure of 52% equity and 48% long-term debt. For the reasons set forth herein, the Commission finds that a 52/48 capital structure as set out in the Stipulation is just and reasonable.

Witness De May testified that the Company's specific debt/equity ratio will vary over time, depending on the timing and size of debt issuances, seasonality of earnings, and dividend payments to the parent company. Tr. Vol. 4, p. 43. As of the end of the test year, the actual regulatory capital structure[1] was 52.8% equity and 47.2% debt, id. at 72, and the 13-month average equity ratio was 54.8%. Id. The 13-month average equity ratio maintained by DEC through November 2017 was 53.3%. Id. The 52/48 capital structure agreed to in the Stipulation represents a compromise between the Company's 53/47 position and the Public Staff's recommendation of a 50/50 capital structure. Both Public Staff witness Parcell and DEC witness De May supported the agreed upon 52/48 capital structure ratios. Tr. Vol. 26, p. 894. DEC witness De May testified that the 52/48 capital structure ratios reflect a reasonable compromise, and also incorporate a reduction from the Company's currently authorized 53/47 capital structure ratios. Tr. Vol. 4, p. 88. Witness Hevert's settlement testimony also supported the stipulated 52/48 capital structure and he stated that the stipulated capital structure is reasonable when viewed in the context of the overall Settlement, and would be positively viewed by the ratings agencies that set the Company's credit ratings. Tr. Vol 4, p. 426. CUCA witness O'Donnell and AGO witness Woolridge recommended that the Commission reject the Company's capital structure proposal and instead advocate a 50/50 hypothetical capital structure. To support their recommended 50/50 capital structure ratios, CUCA witness O'Donnell and AGO witness Woolridge compared DEC's capital structure proposal to either the average common equity ratio of the comparable groups used by the witnesses to determine the recommended return on equity, the capital structure of Duke Energy Corporation,

[1] Regulatory capital structure excludes short-term debt and losses on unregulated subsidiaries.

the parent holding company of DEC, or the average common equity ratio authorized by state commissions in regulatory proceedings in 2017.

In rebuttal testimony, DEC witnesses De May and Hevert pointed out that the comparable groups used by each of the witnesses include several parent holding companies with regulated operating company electric utility subsidiaries. Noting that DEC is a utility operating company subsidiary, witness De May testified that it is an inappropriate comparison to include holding companies, i.e., an apples-to-oranges comparison. The Commission has previously commented on and rejected the use of parent company capital structures as opposed to operating company capital structures in determining the operating utility's appropriate equity/debt ratio. (See Order Granting General Rate Increase and Approving Amended Stipulation, Docket No. E-7, Sub 909, pp. 27-28) (December 7, 2009) (2009 DEC Rate Order). Parent and utility operating companies simply do not necessarily have the same capital structures, because, as witness Hevert points out, financing at each level is driven by the specific risks and funding requirements associated with their individual operations. Tr. Vol. 4, p. 287. In addition, witness Hevert notes that the use of the operating subsidiary's actual capital structure – that is, the capital actually funding the utility operations that provide service to customers – is entirely consistent with precedent of the Federal Energy Regulatory Commission (FERC), so long as three criteria are met: the operating subsidiary (1) issues its own debt without guarantees; (2) has its own bond rating; and (3) has a capital structure within the range of capital structures for comparable utilities. Tr. Vol. 4, pp. 287-88. DEC issues its own debt and is rated separately from its parent company, and since the evidence presented by witnesses Hevert and De May shows the DECs capital structure is generally comparable to that of other operating companies, especially vertically integrated electric utilities, the Commission notes that all three criteria are met. For example, in his rebuttal testimony, witness De May presented the capital structures of four large operating electric utilities located in the southeastern United States at December 31, 2013-16, and at the end of the third quarter of 2017. The averages for these four utilities, Florida Power & Light, Virginia Electric & Power, South Carolina Electric and Gas, and Georgia Power, were 60.7%, 52.9%, 51.4%, and 50.8%. Excluding the highest, Florida Power & Light, the average of the remaining three is 51.7% common equity. Id. at 63. Further, as witness De May testified, for the same reason it is inappropriate to use a proxy group including holding companies, it is inappropriate to apply the capital structure of Duke Energy Corporation to DEC. Id. at 77.

In addition, in the 2013 DEC Rate Case, the AGO argued that a 50/50 capital structure should be implemented for DEC, but, like witness Woolridge in this case, provided "no probative or persuasive evidence suggesting that a 50/50 capital structure is in fact appropriate." 2013 DEC Rate Order, p. 52. The Commission rejected the AGO's argument because that argument did not "recognize the pitfalls were the Commission to order in this case a capital structure at odds with the structure supported by the testimony of the expert witnesses and in line with the Company's actual capital structure in recent years." Id. at 53.

Those pitfalls are readily apparent. First, as witness De May stated, "a 50/50 capital structure would place pressure on…[the Company's "A" level credit rating] by affecting DEC's credit metrics. It would also likely negatively impact the ratings agencies' assessment of qualitative factors, in that movement away from the optimum 53/47 capital structure will likely be viewed as a step away from a credit supportive regulatory environment." Tr. Vol. 4, p. 76.[1] Second, as the Commission has already held in this case in connection with its rate of return on equity discussion, the ratings agencies' "assessment of qualitative factors" is vitally important to the maintenance of the Company's credit quality and to the cost of capital:

> The utilities the Commission regulates compete in a market to raise capital. Financial analysts, rating agencies, and investors themselves scrutinize with great care the regulatory environment and decisions in which these utilities operate. The regulatory environment includes the utilities commissions, consumer advocates, the state legislature, the executive branch and the appellate courts. <u>When regulatory risk is high, the cost of capital goes up.</u>

2013 DEC Rate Order, p. 37 (emphasis added).

As noted above, CUCA witness O'Donnell also compared DEC's proposed capital structure to the average common equity ratio granted by state commissions in regulatory proceedings in 2017. Based upon such data from SNL, this average common equity ratio was 49.1%. DEC witness Hevert testified in rebuttal that when he excluded proceedings for distribution-only utilities, since DEC is a vertically-integrated electric utility, and excluded proceedings in jurisdictions such as Michigan, Indiana, and Arkansas, that unlike North Carolina, include non-investor supplied sources of capital or use "fair value" rate base in determining a ratemaking capital structure, the authorized equity ratios ranged from 40.25% to 58.18% and the average authorized equity ratio was 50.51%. Tr. Vol. 4, pp. 389-90.

In its brief, the AGO contends that the evidence does not support the need for a capital structure that funds rate base using more than 50% common equity and the excessive reliance on equity in DEC's capital structure will cost ratepayers millions of dollars a year unnecessarily. The AGO states that the high equity ratio of DEC – which is maintained between 52-53% equity – helps to lift up the consolidated capital structure of Duke Energy Corporation. The AGO notes that DEC has the highest secured credit ratings of any of Duke Energy Corporation's subsidiaries and is rated higher than most electric utilities. Thus, the high quality ratio maintained by DEC has obvious benefits for Duke Energy Corporation – particularly in ratings by Standard & Poor's, where consolidated entities are evaluated as a family of risk and assigned a family rating. However, the AGO states that the issue is whether maintaining such a high equity ratio is cost effective for DEC ratepayers. The Commission notes that higher credit ratings translate to lower borrowing costs that certainly benefit ratepayers.

CUCA's brief states that DEC witnesses arrived at a very "equity rich" position of capital structure, recommending that DEC be granted an equity ratio, for ratemaking purposes of 54%. All of the other "expert" witnesses proposed some form of a "pro forma" capital structure closer to 50/50. CUCA pointed out that the cost of equity is higher than debt. Thus, the higher the equity

[1] Witness De May indicated in his Settlement Testimony that the slight move away from the 53/47 proposed capital structure represented by the Stipulation would likely still be viewed as credit supportive by the ratings agencies. Tr. Vol. 4, p. 84. In any event, a 50/50 structure is a far cry from a 52/48 structure – each percentage point of reduction in equity represents a $10 million reduction in revenue requirement, which is certainly significant in evaluating the effect of further reduction on the Company's credit metrics.

ratio authorized by the Commission, the higher rates that have to be set and paid by customers to support this additional equity element in the capital structure.

In addition to its analysis of witness testimony as set out above, the Commission also gives weight to the Stipulation and the benefits that it provides to DEC's customers, which the Commission is obliged to consider as an independent piece of evidence under the Supreme Court's holdings in CUCA I and CUCA II. As with all settlement agreements, each party to the Stipulation gained some benefits that it deemed important and gave some concessions for those benefits. Based on DEC's Application and pre-filed testimony, it is apparent that the Stipulation ties the 52/48 capital structure to substantial concessions the Company made to reduce its revenue requirement and to alleviate the impact of the rate adjustment on customers.

Finally, the Commission has also carefully considered changing economic conditions in connection with its capital structure determination, including their effect upon the Company's customers. As discussed in the rate of return on equity section above, which is incorporated herein, the public witnesses in this case provided extensive testimony concerning economic stress they are currently experiencing and have experienced for the last several years. The Commission accepts as credible and probative this testimony. Likewise, the Commission gives significant weight to the testimony of witness De May regarding the Company's need to raise capital at this time to finance the improvements needed for safe, adequate, and reliable electric service.

As in the case of the return on equity, the Commission recognizes the financial difficulty that the adjustment in DEC's rates may create for some of DEC's customers, especially low-income customers. The Commission must weigh this impact against the benefits that DEC's customers derive from DEC's ability to provide safe, adequate, and reliable electric service. Safe, adequate, and reliable electric service is essential to support the well-being of the people, businesses, institutions, and economy of North Carolina. The improvements to the Company's system are expensive, but provide tangible benefits to all of the Company's customers. The Commission concludes that the 52/48 capital structure approved by the Commission in this case appropriately balances the benefits received by customers with the costs to be borne by customers, including higher rates which some customers will find difficult to pay.

Accordingly, the Commission finds and concludes that the recommended capital structure of 52% common equity and 48% long-term debt is just and reasonable to all parties in light of all the evidence presented.

Cost of Debt

In its Application and supporting testimony, the Company proposed a long-term debt cost of 4.74%. Tr. Vol. 4, p. 46. The Stipulation provides for a 4.59% cost of debt. The Commission finds for the reasons set forth herein that 4.59% cost of debt is just and reasonable.

In his pre-filed direct testimony, Company witness De May testified that the Company's revenue requirement was determined using an embedded cost of long-term debt of 4.74% at the end of the test year. Tr. Vol. 4, p. 78.

In pre-filed direct testimony, Public Staff witness Parcell did not use the Company's cost of debt in his analysis. Instead, he used 4.57%, which, he testified, was DEC's "actual embedded cost of debt following the issuance of new long-term debt in November of 2017." Tr. Vol. 26, p. 838.

In his rebuttal testimony, witness De May testified that the Company did not agree with moving from the test year to a cost of debt through November 2017. Instead, the Company recommended that the cost of debt be updated through December 2017, which equaled 4.59%. Tr. Vol. 4, p. 78.

In his testimony in support of the Settlement, Public Staff witness Parcell agreed with the embedded cost of debt at 4.59%.

No intervenor offered any evidence to contradict the use of 4.59% as the cost of debt. The Commission therefore finds and concludes that the use of a debt cost of 4.59% is just and reasonable to all parties in light of all the evidence presented.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 20

The evidence supporting this finding and conclusions is contained in the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, the Stipulation, and the entire record in this proceeding.

The Stipulating Parties reached a partial settlement with respect to some of the revenue requirement issues presented by the Company's Application, including those arising from the supplemental and rebuttal testimonies and exhibits. As discussed above, the revenue requirement effect of the Stipulation is shown in Boswell Third Supplemental, as well as Stipulation Exhibit 1 Corrected and Revised McManeus Stipulation Exhibit 1 - Updated for Post-Hearing Issues, which provides sufficient support for the annual revenue required on the issues agreed to in this Stipulation.[1] Section III of the Stipulation outlines a number of accounting adjustments to which the Stipulating Parties have agreed. Public Staff witness Boswell presented schedules showing the financial impact of the Stipulation, as well as the amount of the rate increase that would result if the Commission agrees with the Company on all of the unresolved items, or, alternatively, agrees with the Public Staff on all of these items. The accounting adjustments that are not specifically addressed in other findings and conclusions are discussed in more detail below.

Aviation Expenses

In its initial and revised supplemental filing, the Company removed 39.93% of the Company's O&M costs related to corporate aviation. Public Staff witness Boswell made a further

[1] The Stipulation provides that no Stipulating Party waives any right to assert a position in any future proceeding or docket before the Commission or in any court, as the adjustments agreed to in the Stipulation are strictly for purposes of compromise and are intended to show a rational basis for reaching the agreed-upon revenue requirement without either party conceding any specific adjustment. The Stipulating Parties also agreed that settlement on these issues will not be used as a rationale for future arguments on contested issues brought before the Commission.

adjustment after investigating the aviation expenses charged to DEC during the test year. Based on the Public Staff's review of flight logs, the corporate aircraft are available for use by Duke Energy Corporation's Chief Executive Officer (CEO) and DEC staff. The Public Staff recommended that certain expenses allocated to DEC be removed due to the nature of the flights involved. Tr. Vol. 26 p 591-92. For the purposes of settlement, the parties agreed to an adjustment that removes 50% of the Company's corporate aviation O&M expense.

Executive and Incentive Compensation

In its Application, the Company removed 50% of the compensation of the four Duke Energy executives with the highest level of compensation allocated to DEC during the Test Period. Witness McManeus explained that while the Company believes these costs are reasonable, prudent, and appropriate to recover from customers, DEC has, for purposes of this case, made an adjustment to this item. Tr. Vol. 6, p. 253.

Public Staff witness Boswell recommended removal of 50% of the compensation for a fifth executive, as well as 50% of the benefits associated with the top five executives. Tr. Vol. 26, p. 587. She explained that executive compensation and benefits should be excluded because these executives' duties are closely linked to shareholder interests. Id. at 587-88. Witness Boswell also recommended disallowance of incentive compensation related to earnings per share (EPS) and total shareholder return (TSR). Id. at 590-91. She asserted that incentive compensation tied to EPS and TSR metrics should be excluded because it provides a direct benefit to shareholders only, rather than to customers. Id. at 591.

In his rebuttal testimony, Company witness Silinski testified that these proposed adjustments are inappropriate and should be rejected by the Commission. Tr. Vol. 26, p. 241. Witness Silinski explained that witness Boswell erroneously assumes a divergence of interests between shareholders and customers that has not been demonstrated to exist. Id. at 249. According to witness Silinski, to the contrary, employee compensation and incentives tied to metrics such as EPS and TSR benefit customers because those metrics reflect how employees' contributions translate into overall financial performance. Id. He testified that EPS, for example, is a measure of the Company's performance, and that performance is reflective of how certain goals – safety, individual performance, team performance, and customer satisfaction (all of which are components of incentive pay) are met in a cost-effective way. Id. Divorcing employee performance from such an important measure of a rate regulated company's overall health is unreasonable and counterproductive. Id. Additionally, witness Silinski explained that in order to attract a well-qualified and well-led workforce, the Company must compete in the marketplace to obtain the services of these employees. Id. at 250. The recommended adjustments would render the Company's compensation uncompetitive with the market, resulting in the inability to attract and retain the talent the Company needs to run a safe and reliable electric system. Id. at 246. Finally, witness Silinski pointed out that no witness in this proceeding challenges the reasonableness of the level of compensation expenses reflected in the ratemaking test period for the Company. Id. at 250. The Stipulation provides that "[t]he Company accepts the Public Staff's proposed adjustment to executive compensation to remove 50% of the compensation for the five Duke Energy executives with the highest amounts of compensation, and to remove 50% of the benefits associated with those five executives." Stipulation, § III.E.

As part of the Stipulation, the parties agreed to accept the Public Staff's adjustment with a modification to limit the incentives removed. This agreement is reflected in Section III.H. of the Stipulation, which provides that the Company's employee incentives should be adjusted to remove the cost of the STIP based on the Company's EPS for employees who qualify for the Company's LTIP.

Outside Services

Witness Boswell testified that the Public Staff reviewed costs for outside services associated with expenses that were indirectly charged to DEC by DEBS as well as those incurred by the Company directly that were incurred during the test period. Tr. Vol. 26, p. 592. Public Staff witness Boswell stated that the Public Staff's investigation revealed charges that were related to legal services for coal ash and groundwater issues related to coal ash. Id. She recommended removing these expenses from O&M in the test period. Id. Witness Boswell noted that the Public Staff also found certain expenses that were allocated to DEC that should have been directly assigned to other jurisdictions that she recommended should be removed. Id. at 592-93.

In her rebuttal testimony, witness McManeus noted that the Company agrees with approximately $665,000 of the $2,124,000 adjustment proposed by the Public Staff. Tr. Vol. 6, p. 307. She explained that the portion of the adjustment that the Company opposes is primarily related to legal services related to coal ash and groundwater issues, because the Company takes the position that these costs were reasonable and prudent and, therefore, should be recovered from customers. Id. Pursuant to Section III.F of the Stipulation, the Company agreed to remove certain costs associated with outside services, as stated in its rebuttal filing. This amount does not include costs incurred for certain legal services related to coal ash, which remain in the Unresolved Issues.

Costs to Achieve Duke Energy-Piedmont Merger

On September 29, 2016, in Docket No. E-7, Sub 1100, Docket No. E-2, Sub 1095, and Docket No. G-9, Sub 682, the Commission issued its Order Approving Merger Subject to Regulatory Conditions and Code of Conduct (Merger Order), which approved the merger between Duke Energy and Piedmont. Ordering paragraph 7(b) of the Merger Order, which addresses the ratemaking treatment of costs incurred to achieve the merger, states:

> DEC, DEP, and Piedmont may request recovery through depreciation or amortization, and inclusion in rate base, as appropriate and in accordance with normal ratemaking practices, their respective shares of capital costs associated with achieving merger savings, such as system integration costs and the adoption of best practices, including information technology, provided that such costs are incurred no later than three years from the close of the merger and result in quantifiable cost savings that offset the revenue requirement effect of including the costs in rate base. Only the net depreciated costs of such system integration projects at the time the request is made may be included, and no request for deferrals of these costs may be made.

(Emphasis added).

During the test year in this case, DEC included in operating expenses approximately $6.5 million on a North Carolina retail basis that it identified as systems and transition costs to achieve merger savings. Tr. Vol. 26, p. 594. Witness Boswell contended that the Merger Order only allows the Company to recover the capital costs associated with achieving merger savings, such as system integration costs. Id. As such, the Public Staff removed the $6.5 million of O&M expenses that DEC identified as systems and transition costs to achieve merger savings.

In her rebuttal testimony, witness McManeus explained that the Company opposed this adjustment. Tr. Vol. 6, p. 326. She noted that the costs that witness Boswell has removed are operating expenses, not capital costs. Id. According to witness McManeus, the Merger Order does not specifically address cost recovery for operating expenses associated with achieving merger savings. Id. Witness McManeus explained that should the Commission decide to exclude these expenses from recovery in this case, a deferral order would allow the Company to treat these costs like capital for ratemaking purposes. Id.

Notwithstanding their differing positions on the costs to achieve the Duke Energy-Piedmont merger, in the spirit of settlement and in the context of the Stipulation as a whole, the Company and the Public Staff have resolved this issue. Accordingly, the Stipulation provides that the Company accepts the Public Staff's proposed adjustment to remove costs to achieve the Duke Energy-Piedmont merger.

Sponsorships and Donations

Public Staff witness Boswell adjusted the Company's O&M Expenses to remove amounts paid for sponsorships and charitable donations. Specifically, she excluded from expenses amounts paid to the U.S. Chamber of Commerce, other chambers of commerce, the NC Chamber Foundation, and political-related donations. Tr. Vol. 26, p. 599. Witness Boswell argued that these expenses should be disallowed because they do not represent actual costs of providing electric service to customers. Tr. Vol. 26, p. 599. In her rebuttal testimony, witness McManeus testified that Chambers of Commerce promote business and economic development which in turn helps to retain and attract customers to DEC's service territory. Tr. Vol. 6, p. 311. She explained that funds paid to Chambers of Commerce that are not specified as a donation or lobbying on the Chamber invoice are generally assumed to be in support of business or economic development and are considered to be properly charged as a utility operating expense that should be included in the Company's cost of providing electric service to customers. Id. at 311-12. As a result, the Company opposed a portion of witness Boswell's proposed adjustment. Id. at 12. Witness McManeus also noted that in reviewing the adjustment proposed by witness Boswell, the Company determined that $5,261 of the charges in question were reclassified during the test period to FERC Account 426, which is excluded from cost of service. Id. Pursuant to Section III.K of the Stipulation, the Public Staff agreed to accept the Company's rebuttal position on sponsorships and donations expense, which removed amounts paid to the U.S. Chamber of Commerce and certain other expenses.

Lobbying and Board of Director Expenses

Witness Boswell made an adjustment to remove 50% of the expenses associated with the Board of Directors of Duke Energy that have been allocated to DEC. Tr. Vol. 26, p. 589. She argued that the Board of Directors has a fiduciary duty to protect the interests of shareholders, which may differ from the interests of ratepayers. Id. Accordingly, the Public Staff believes it is appropriate for the shareholders of the larger electric utilities to bear a reasonable share of the costs of compensating the Board of Directors, as well as the cost of insurance for these individuals. Id. Witness Silinski explained that the Company is required to have a Board of Directors and that the costs of being an investor-owned utility, including Board costs, are in fact costs of service. Id. at 252. He argued that it is not fair or reasonable to penalize the Company for being an investor-owned utility with attendant requirements to that corporate structure. Id. at 252-53.

With respect to lobbying expenses, witness Boswell noted that the Company made an adjustment to remove some lobbying expenses from the test year. Tr. Vol. 26, p. 595. She further adjusted O&M expenses to remove what she characterized as additional lobbying costs, including O&M expenses that she believed were associated with stakeholder engagement, state government affairs, and federal affairs that were recorded above the line. Id. at 595-96. In her rebuttal testimony, witness McManeus explained why the Company opposed this adjustment and disagreed with witness Boswell's characterization of these expenses. Tr. Vol. 6, p. 327. Witness McManeus testified that in 2016, the Company engaged a third-party consulting company to perform a detailed time study for the purposes of determining the percentage of time certain individuals spent on lobbying activities per the federal definition in 29 Code of Federal Regulations Section 367.4264. Id. A report with the results of the study was delivered to the Company in August 2016, and the Company booked journal entries to ensure that the 2016 labor costs were aligned with the results of the independent study. Id. Witness McManeus concluded that no further adjustments were warranted. Id.

Nevertheless, in the spirit of settlement and in the context of the Stipulation as a whole, the Company and the Public Staff have resolved these issues, and in Section III.K. of the Stipulation, the Company agreed to accept the Public Staff's recommended adjustments to lobbying and Board of Directors' expenses.

Allocations by DEBS to DEC

DEBS is the company that provides services to various affiliated entities of Duke Energy Corporation. The affiliated entities have a Cost Allocation Manual (CAM) that documents the guidelines and procedures for allocating costs between the entities to ensure that one entity does not subsidize another. As discussed above, during the test year, Duke Energy acquired Piedmont and the Commission approved the merger on September 29, 2016. According to Public Staff witness Boswell, this change, along with updates related to other affiliated entities, has caused the DEC allocation factors to decrease. Tr. Vol. 26, p. 595. Witness Boswell made an adjustment to reflect the fact that O&M expenses allocated to DEC from DEBS will be less going forward. Id. In her rebuttal testimony, witness McManeus explained that the Company did not agree with witness Boswell's adjustment because she included only three months of costs related to Piedmont, which results in a mismatch between the allocation factors and the costs to which they are being applied. Tr. Vol. 6, 323. In her supplemental testimony, witness Boswell updated the adjustment to include a full 12 months of the impact of the Piedmont acquisition into the adjustment and noted that the Company did not oppose this adjustment. Tr. Vol. 6, p. 617. As part of settlement, the parties agreed to accept the Public Staff's adjustment regarding the DEBS to DEC allocation as set forth in the supplemental testimony of Public Staff witness Boswell. Stipulation, § III.M.

Salaries and Wages

In her direct testimony and schedules, Company witness McManeus included an adjustment to annualize and normalize O&M labor expenses to reflect annual levels of costs as of April 1, 2017. The adjustment also restated variable short and long term pay to the target level. Tr. Vol. 6 p. 262. This adjustment was further updated in her supplemental filings. In her supplemental testimony, Witness Boswell explained that she adjusted the Company's updated payroll to reflect annualized payroll through December 31, 2017. Tr. Vol. 26, p. 616. For DEBS payroll allocated to DEC she applied the updated allocation factor only to the increase in payroll between December 31, 2016 and December 31, 2017, as the test year amount is included in the DEBS to DEC allocation adjustment discussed above. See id. She noted that the Company does not oppose this adjustment, as updated in witness Boswell's second supplemental filing. Id. The Stipulation provides that the Company accepts the Public Staff's methodology as to how to calculate salaries and wages as set forth in the supplemental testimony of witness Boswell. Stipulation, § III.N. Boswell Third Supplemental and Stipulation Exhibit 1 Corrected and McManeus Revised Stipulation Exhibit 1 – Updated for Post-Hearing Issues update the salaries and wages adjustment to reflect the Company and Public Staff's resolution on how to quantify the agreement reached in Section III.N of the Stipulation.

Upon consideration of all of the evidence in this proceeding, including the Stipulation which the Commission accepts in its entirety and upon which the Commission places great weight, the Commission finds and concludes that the stipulated adjustments discussed herein are just and reasonable to all parties and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 21

The evidence supporting this finding of fact and conclusions is contained in the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, the Company and Public Staff Agreement and Stipulation of Partial Settlement, and the entire record in this proceeding.

In this case, the Company included an adjustment to amortize the excess deferred state income taxes that it deferred pursuant to the Commission's May 13, 2014 Order in Docket No. M-100, Sub 138. In its Application, the Company proposed that the State EDIT liability included in this case be returned to customers over a five-year period. Tr. Vol. 6, p. 263. Public Staff witness Boswell testified that it would be beneficial to return the State EDIT to customers through a rider that would expire at the end of a two-year period. Tr. Vol. 26, p. 600.

In the Stipulation, the parties agreed that the State EDIT liability should be returned to customers through a levelized rider that will expire at the end of a four-year period. Stipulation,

§ III.B. The Stipulating Parties provide that the appropriate level of State EDIT to be refunded to customers is $60,102,000 annually for the four years following the effective date of the rates approved in this proceeding. See Boswell Second Supplemental and Stipulation Exhibit 1; see also Revised McManeus Stipulation Exhibit 1 – Updated for Hearing. No intervenor took issue with this provision of the Stipulation. Accordingly, the Commission finds and concludes that the four-year State EDIT rider as set forth in Section III.B of the Stipulation is just and reasonable to all parties in light of all the evidence presented, and is hereby approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 22

The evidence supporting this finding of fact and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

In its Application, the Company requested recovery of certain operations and maintenance O&M expenses associated with its Customer Connect project. Company witness Hunsicker testified about the Company's plans to replace its customer information system (CIS), a project known as "Customer Connect," and the costs and revenue requirement the Company is seeking in this case to support this project. Tr. Vol. 18, pp. 253-64, 281. Witness Hunsicker explained that the Company's current CIS was developed over 20 years ago and was not designed to efficiently support new capabilities. Id. at 257. She stated that the Company and its customers' needs are very different than they were when the original CIS was constructed, and the system is past the point where modular "bolt on" systems or modular upgrades are effective. Id. at 255. Additionally, the Company's current CIS has many deficiencies. For example, the Company's existing CIS is not equipped to handle complex billing arrangements, such as net metering for self-generating customers, and these bills must be manually calculated. Id. at 257-58. The current CIS also does not enable access to account histories nor does it allow customers to employ preferred communication methods. Id. at 258-59. Witness Hunsicker explained that the new CIS will provide universal and simplified processes for customers, improve billing, allow the Company to easily identify and implement new rate structures for customers, and interface with the Company's new AMI technology. Id. at 261. Witness Hunsicker explained that Customer Connect began analysis and design in January 2018, and is currently planned to be in-service for DEC in 2022. Id. at 262. She further explained that the implementation will be phased and that new capabilities will be available to customers each year leading up to full deployment. Id. at 263. The estimated costs for Customer Connect for DEC, North Carolina, is between $220 and $230 million, which is based on the best and final offers for fixed price contracts that the Company negotiated with the software, systems integration, and change management vendors. Id. at 263. Witness Hunsicker explains that the Company is seeking a pro forma adjustment from $4.4 million to $15.1 million in O&M expenses associated with the project to reflect the average expected annual O&M expenses associated with the project from 2018 through 2020. Id. at 264.

Public Staff witness Floyd testified regarding the Public Staff's support of DEC's Customer Connect project. Tr. Vol. 23, p. 80. Witness Floyd described the shortcomings of the Company's current CIS and the improvements offered by the new CIS. Id. at 77-80. He also described the implementation plan for Customer Connect and recommended that the Company make semi-annual reports on the status of the implementation. Id. at 80, 82-83.

Witness Floyd further testified that the $13.3 million of expense related to the Company's initial work on Customer Connect is reasonable. Id. at 83. However, he also testified that Customer Connect was not used and useful as of the test year ending December 31, 2016, and that the full capabilities of Customer Connect will not be realized until the summer of 2022. Id. at 81. Therefore, the Public Staff, through witness Boswell, recommended an adjustment to remove from the Company's revenue requirement, the Customer Connect amounts projected for 2018 through the in-service date, reasoning that the system will not be fully functional until the summer of 2022. Tr. Vol. 26, p. 597.

In her rebuttal testimony, Company witness Hunsicker responded to the Public Staff's recommendation to remove the forecasted amounts of O&M expense between 2018 and the in-service date for Customer Connect. Tr. Vol. 18, p. 266. She explained that the Company has only asked for the level of O&M necessary to deploy the capital for the program, and that DEC is not asking for the program or its costs to be placed into rate base. Id. at 268. These O&M costs are not being capitalized to the program, and in order to be captured, they either need to be included in rates as the Company has requested, or set aside and capitalized to a regulatory asset to be recovered when the project comes online. Id.

Company witness Fountain explained that by entering into the Stipulation, the Company agreed to accept the Public Staff's adjustment to Customer Connect expenses, and the Company shall be authorized to establish a regulatory asset to defer and amortize expenses associated with its Customer Connect project. Tr. Vol. 6, pp. 219-20. Company witness McManeus explained that the Company shall be allowed to accrue a return on the regulatory asset in the same manner that Construction Work in Progress (CWIP) balances accrue AFUDC. Id. at 350. Company witness McManeus explained that AFUDC shall end and a 15-year amortization shall begin on the date Releases 5-8 of the project goes into service or January 1, 2023, whichever is sooner. Id.

Additionally, in order to provide the Commission and other interested parties with information concerning the status of development, spending, and the accomplishments to date, the Stipulating Parties will develop the reporting format and the content of that report within 90 days of the Commission's order approving the Stipulation, with the reports to be filed in this docket for the next five years by December 31 of each year or until Customer Connect is fully implemented, whichever is later. Stipulation, Section III.C.

In its post-hearing Brief, NCSEA cites the testimony of DEC witness Fountain that AMI and DEC's new CIS, Customer Connect, are interlocking components; and contends that if properly implemented together the two systems can provide customers with access to their energy consumption data to enable them to effectively conserve electricity. NCSEA states that it is generally supportive of DEC's investments in AMI and Customer Connect, but that DEC must ensure that Customer Connect can provide customers with energy consumption and allow customers to easily authorize third parties to access such data. NCSEA submits that DEC has failed to show that AMI and Customer Connect will provide these customer benefits. Citing the testimony of DEC witness Hunsicker, NCSEA contends that despite recognizing the benefit of providing consumers with access to their energy consumption data, investing in technology capable of providing consumers such access, and having no issue with providing consumers such access, DEC is not doing so. NCSEA acknowledges that the Commission has directed DEC to meet with NCSEA and other stakeholders to discuss implementing the Green Button Connect protocol for access to energy consumption data, but, nonetheless, submits that DEC has not provided sufficient evidence in this docket that Customer Connect will meet customer needs, comply with industry standards, or is capable of complying with directives from this Commission. As a result, NCSEA asserts that DEC's request for cost recovery for Customer Connect should be denied at this time.

Upon consideration of all of the evidence in this proceeding, including the Stipulation, the Commission approves the stipulated adjustments to the Company's Customer Connect expenses in this proceeding, and the Company shall be authorized to establish a regulatory asset to defer and amortize expenses associated with its Customer Connect project. The Commission finds that an effectively designed and implemented Customer Connect project may provide value to DEC's customers and support continued quality of service.

In arriving at its conclusion, the Commission gives substantial weight to the testimony of witness Hunsicker and witness Floyd regarding the deficiencies with the Company's current CIS and the improvements and new functionalities that the modernized CIS will provide to customers through implementation of the Customer Connect program. Thus, it is appropriate that these costs be deferred and allowed to accrue until the time that Customer Connect goes in-service or by January 1, 2023. Witnesses Hunsicker and Floyd have also testified to the benefits that customers will receive from the Customer Connect program in stages throughout its implementation. The Commission notes that the Company and Public Staff will file with the Commission a proposed Customer Connect reporting format and the content of that report within 90 days of this Order, and that subsequent reports shall be filed annually for the next five years, or until implementation is complete. The reporting will allow the Commission to monitor the status of the Customer Connect project and the associated expenses throughout the implementation process. The Commission recognizes the data access concerns expressed by NCSEA and determines that it is appropriate for the Customer Connect annual report to clearly describe the status of efforts to effectively provide energy consumption data to customers and the precautions taken to ensure data remains secure.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 23-24

The evidence supporting these findings of fact and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony, exhibits, and affidavits of DEC witnesses Fountain, McManeus and Miller, and Public Staff witness Boswell, and the entire record in this proceeding.

In its Application, the Company requested that its capital investment in the Lee CC plant, approximately $557 million, be included in rate base. DEC witness Miller explained that the Lee CC plant was expected to begin commercial operation in November 2017, provide 750 megawatts (MW) of total capacity, and emit carbon dioxide at half the rate and nitrogen and sulfur oxide emissions at a fraction of the rate compared to the plants retired by the Company. Tr. Vol. 26, p. 212. In her testimony, Public Staff witness Boswell proposed the removal of the Company's estimated O&M expenses needed to operate the plant as it represented an estimate, not actual O&M expenses needed to operate the plant. Id. at 580. Additionally, witness Boswell testified that if the Lee CC plant was not in service by the close of the hearing, she recommended removing the plant and related deferral adjustments from rates and including the plant in CWIP to be included in rate base. Id. at 581.

In her second supplemental testimony, Company witness McManeus reduced the amount of estimated incremental O&M costs associated with the Lee CC facility to approximately $1.98 million. Tr. Vol. 18, p. 296. Witness Miller testified that while the Lee CC plant was not yet in service, the Company utilized the actual non-labor O&M expenses for two substantially similar combined cycle plants, Buck and Dan River, to calculate the estimated incremental O&M expenses for Lee CC. Id. at 236. Therefore, according to witness Miller, the Buck and Dan River facilities serve as a reasonable proxy to determine whether the Company's estimated O&M expenses for Lee CC are reasonable. Id. In her supplemental testimony, Public Staff witness Boswell proposed to include a displacement adjustment to reflect the fact that existing plant(s) in the Company's fleet may not run as frequently due to the availability of the new plant. Tr. Vol. 26, p. 620. In his rebuttal testimony, DEC witness Miller stated that a displacement adjustment was not appropriate because Lee CC was built to serve a growing number of customers and the associated growth of energy and peak demand requirements. Id. at 235.

As part of the Settlement, the Public Staff and DEC agreed that for purposes of settlement, DEC would withdraw its adjustment to include incremental O&M expenses and the Public Staff would withdraw its displacement adjustment. Stipulation, § III.L. The Stipulating Parties therefore agreed that the appropriate level of ongoing O&M expense to be included in rates is $0. Id. The Stipulating Parties also agreed that the appropriate amortization period for the deferred expenses associated with the Lee CC facility is four years. Id. Additionally, DEC and the Public Staff agreed that it was appropriate to hold the record open until March 23, 2018, to allow the Company to submit final cost amounts to be included in this proceeding for Lee CC and for Public Staff to use these amounts to file with the Commission the Stipulating Parties' final recommendation with regard to the Lee CC-related revenue requirement, including Lee CC deferred costs, using the methodology recommended by the Public Staff in this proceeding. Id. Further, DEC and the Public Staff agreed to hold the record open to allow the filing by the Company of an affidavit indicating that the plant has closed to service for operational and accounting purposes and that it is used and useful for the benefit of customers. Id.

In accordance with the Stipulation, DEC provided the Public Staff with the final costs of the Lee CC plant on March 23, 2018. On April 10, 2018, the Public Staff filed its updated recommendations regarding Lee CC plant and expense-related items, as shown in Boswell Third Supplemental and Stipulation Exhibit 1. Also on April 10, 2018, the Company filed the Affidavit of Joseph A. Miller, Jr. indicating that as of April 5, 2018, the Lee CC plant closed to service for operational and accounting purposes and is providing DEC with 650 MW of capacity for the benefit of its North and South Carolina customers. On April 19, 2018, the Company filed Revised McManeus Stipulation Exhibit 1 – Updated for Post-Hearing Issues, which, among other things, reflects updates to the Lee CC plant and expense-related items to reflect final costing information for inclusion in this proceeding, including updates to plant investment, related deferred income taxes, depreciation, materials and supplies, and the deferral of those costs between the plant's operation date and the date rates are expected to become effective. On April 19, 2018, the Public Staff filed Boswell Third Supplemental and Stipulation Exhibit 1 Corrected, which, among other things, corrects the Lee CC addition to plant in service and corrects the Lee CC deferral calculation.

No intervenor took issues with these provisions of the Stipulation. Upon consideration of all of the evidence in this proceeding, including the Stipulation, which the Commission accepts in its entirety and upon which the Commission places great weight, the Commission finds and concludes that it was appropriate to keep the record open to allow the Company the additional time to attest to the commercial operation of the Lee CC facility and the Stipulating Parties to resolve the final cost amount to be included for recovery in this proceeding. The Commission appreciates the Stipulating Parties working together to resolve this matter economically. Because the conditions of the Stipulation have been met in a timely and appropriate manner, the Commission finds and concludes that DEC's request to recover the final cost amounts included in this case for the Lee CC plant, as adjusted by the Stipulating Parties and reflected in Boswell Third Supplemental and Stipulation Exhibit 1 Corrected and Revised McManeus Stipulation Exhibit 1 – Updated for Post-Hearing Issues, is just and reasonable to all parties in light of all the evidence presented.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 25

The evidence supporting this finding and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

In her direct testimony, Company witness McGee testified to the Company's position that the beneficial reuse of coal ash constitutes a sale of by-product produced in the generation process, and therefore, associated gains and losses on the sale should be included in the fuel adjustment clause under N.C. Gen. Stat. § 62-133.2(a1)(9). Tr. Vol. 26, pp. 195-97. She explained that the Company excluded net loss amounts for September 2017 through August 2018, related to the sale of coal ash produced at the Company's Riverbend coal plant, from its March 8, 2017 fuel filing, pending the Commission decision in this proceeding. Id.

Public Staff witness Lucas testified that the costs relating to the disposal of coal ash from Riverbend to the Brickhaven facility in Chatham County, North Carolina, to the extent they are reasonable and prudent, should be recovered in base rates and not through the fuel adjustment clause because such costs did not result from sale of coal ash.

In Section III. P of the Stipulation, DEC withdrew its request to recover certain CCR costs through the fuel adjustment clause related to the excavation and movement of CCRs from Riverbend to Brickhaven. The Stipulation also provides that the recovery of these costs are left in the Company's deferred CCR balance for consideration of recovery in the Company's base rates.

No intervenor contested these provisions of the Stipulation. Accordingly, the Commission finds and concludes that the provisions of the Stipulation regarding the consideration of recovery of certain CCR costs through base rates, rather than fuel, as set forth in Section III.P of the Stipulation are just and reasonable to all parties in light of all the evidence presented, for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 26

The evidence supporting this finding and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

Company witness McGee also testified with respect to the amount of fuel that should be included in base rates. In her direct testimony she testified that she supported the fuel component of proposed base rates for all customer classes and the fuel pro forma adjustments to the test year operating expenses contained in McManeus Exhibit 1. Tr. Vol. 26, pp. 191-92. Witness McGee proposed to use the total prospective fuel and fuel-related costs factors that DEC proposed on March 8, 2017 in Docket No. E-7, Sub 1129. Id. Witness McGee explained that DEC's intent in using the fuel-related factors that were proposed at the time the Company's Application was prepared as a component of its proposed new rates was to make it clear that the Company is requesting a rate increase that relates to non-fuel revenues only. Id. at 194. In her testimony, Public Staff witness Boswell recommended that the base fuel and fuel-related cost factors be updated to reflect the rates that were actually approved by the Commission in that docket. Tr. Vol. 26, p. 584. In her rebuttal testimony, Company witness McManeus stated that the Company did not oppose the Public Staff's recommendation. Tr. Vol. 6, p. 305. Accordingly, Section IV. B. of the Stipulation sets forth the Stipulating Parties' agreed upon total of the approved base fuel and fuel related cost factors, by customer class, as set forth below (amounts are ¢/kWh excluding regulatory fee):

• Residential	1.7828 cents per kWh
• General Service/Lighting	1.9163 cents per kWh
• Industrial	2.0207 cents per kWh

Tr. Vol. 6, p. 354.

According to witness McGee, the Company will continue to bill customers the fuel rates authorized by the Commission in its annual fuel proceedings. Tr. Vol. 26, p. 194. As such, there will be no change in customers' bills as a result of including these fuel cost factors in the proposed base rates. Id. As shown on Boswell Third Supplemental and Stipulation Exhibit 1, Schedule 3-1(t), the Company's North Carolina retail adjusted fuel and fuel-related costs expense for the Test Period was $1,082,899,000. This amount was calculated using the base fuel factors identified above and North Carolina retail test period actual kWh sales by customer class as adjusted for weather and customer growth. Tr. Vol. 26, p. 193.

No intervenor contested these provisions of the Stipulation. Accordingly, the Commission finds and concludes that the provisions of the Stipulation regarding the base fuel and fuel-related cost factors as set forth in Section IV.B of the Stipulation are just and reasonable to all parties in light of all the evidence presented, for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 27

The evidence supporting this finding and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

The Company's proposed adjustment for coal inventory, as reflected in its Form E-1, Item 10, Adjustment NC-1600, set the inventory balance to 40 days of 100% full load burn, resulting in a reduction to the materials and supplies component of cash working capital in this case. Tr. Vol. 23, p. 18. This is the level of coal inventory that was used in DEC's last general rate case for the materials and supplies component of cash working capital and was stipulated to by the Public Staff and the Company in the settlement agreement approved by the Commission in that case. Id.

In his pre-filed testimony, Public Staff witness Metz recommended adjusting the materials and supplies component of cash working capital to reflect a 40-day coal inventory based on a 70% full load burn. Id. at 25. He testified that a 70% capacity factor represents a reasonable estimate of the Company's coal fleet performance during peak conditions, though he would expect that the Company would adjust its inventory based on anticipated seasonal needs. Id. at 25-26. Witness Metz based his recommendation on DEC's historical trends and predicted use of the Company's coal fleet, as well as DEC's lower delivered fuel prices due to closer proximity to coal sources, combined with the efficiency of the Company's coal generation technology. Id. at 27.

In his rebuttal testimony, Company witness Miller explained that the Company actually contemplated requesting an increase in the full load burn inventory target to enable the Company to respond to un-forecasted increases in coal generation demand, given the increased volatility in coal generation due to factors such as fluctuating natural gas prices and weather-driven demand. Tr. Vol. 26, p. 228. However, the Company determined that it was prudent to continue to operate under the current 40-day full load burn inventory target and made a pro forma adjustment reducing its actual coal inventory at the end of the Test Period to reflect this. Id.

Witness Miller testified that adopting witness Metz's recommendation of a 40-day coal inventory based on a 70% full load burn could lead to negative supply, delivery, and operational impacts. Id. at 228-29. He testified further that his recommendation fails to contemplate the factors that impact a reliable fuel supply, including volatility in coal generation demand, delivery and/or supply risks, and generation performance. Id. at 228-29. In particular, he noted that witness Metz's recommendation assumes there will be ample amounts of coal available during higher demand periods and does not contemplate the increased demand from other utilities during the same period of increased demand being experienced by the Company. Id. at 228-31. Witness Miller explained that a 40-day, 70% capacity factor equates to only a 28-day full load burn at 100% during periods of peak demand. Id. at 228. According to witness Miller, if DEC is unable to dispatch cost-competitive coal generation during peak demand due to unreliable inventory levels, it will have to seek alternatives such as dispatching higher cost generation, paying higher prices for fuel, or purchase power. Id. As such, having unreliable coal inventory levels could result in unfavorable impacts on customers. Id. at 229.

In the Stipulation, the Public Staff and DEC agreed that for purposes of settlement, the Company may set carrying costs included in base rates reflecting a 35-day coal inventory at 100% capacity factor, and that a coal inventory rider should be allowed to manage the transition. More specifically, the Stipulating Parties propose that this increment rider shall be effective on the same date as new base rates approved in this proceeding and continuing until inventory levels reach a 35-day supply to allow the Company to recover the additional costs of carrying coal inventory in excess of a 35-day supply (priced at $73.23 per ton). The rider will terminate the earlier of (a) May 31, 2020 or (b) the last day of the month in which the Company's actual coal inventory levels return to a 35-day supply on a sustained basis.[1] The Stipulation provides that for this purpose, three consecutive months of total coal inventory of 37 days or below will constitute a sustained basis. The Company will adjust this rider annually, concurrent with DEC's DSM/EE Rider, REPS Rider, and Fuel Adjustment Rider, and any over- or under-collection of costs experienced as a result of this rider shall be reconciled in that annual rider proceeding. Additionally, the Stipulation provides that any interest on any under- or over-collection shall be set at the Company's net-of-tax overall rate of return, as approved by the Commission in this proceeding. Finally, the Company agreed to conduct an analysis in consultation with the Public Staff demonstrating the appropriate coal inventory level given market and generation changes since the Company's last rate case (Docket No. E-7, Sub 1026), with such analysis to be completed by March 31, 2019.

No intervenor took issues with this provision of the Stipulation. The Commission finds and concludes that the reduction to coal inventory included in working capital and the establishment of the increment rider to allow the Company to recover the additional costs of carrying coal inventory in excess of a 35-day supply, as provided in the Stipulation, is just and reasonable to all parties in light of all the evidence presented.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 28

The evidence supporting this finding of fact and conclusions is contained in the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

Summer Coincident Peak

DEC based its filing in this case on the summer coincident peak (SCP) methodology for allocation of the cost of service among jurisdictions and among customer classes. The Public Staff, CIGFUR III, CUCA, and Kroger concur with DEC's use of the SCP methodology for cost allocation. No intervenors presented testimony in opposition to the Company's use of the SCP methodology for cost allocation. Moreover, the Stipulation provides for the use of the SCP methodology for purposes of settlement.

Company witness Hager testified in support of the SCP methodology for allocation among jurisdictions and among customer classes. She explained that a coincident peak allocator assigns

[1] The Stipulation provides that the Company reserves the right to request an extension of the May 31, 2020 date.

the fixed demand-related costs to the jurisdictions and customer classes in proportion to their respective contribution to the system's maximum hourly demand during the test period. Tr. Vol. 19, pp. 24-25.

Each jurisdiction's and customer class' cost responsibility (i.e. the percentage of the fixed portion of production and transmission demand costs assigned to each jurisdiction and customer class) is equal to the ratio of their respective demand in relation to the total demand placed on the system. Id. at 25. The cost of service study supporting the Company's proposed rate design in this proceeding allocates the fixed portion of production and transmission demand-related costs based upon a jurisdiction's and customer class' coincident peak responsibility occurring during the summer. Id.

DEC's peak system demand for the test year, occurred on July 27, 2016, at the hour ending at 5:00 p.m. Id. This was also the peak generation and transmission demand used in the Company's cost of service study for the test year. Id. Witness Hager explained that the SCP in the test year is within the range of previous SCP occurrences, and it is therefore appropriate to assign fixed demand-related costs to the Company's jurisdictions and customer classes based upon the SCP. Id. at 26.

The Public Staff agreed with the Company's use of the SCP cost of service methodology. The Stipulation reflects that the "Public Staff does not oppose the Company's cost of service study and allocation methodology for purposes of settlement in this case only, with the exception of coal ash costs, which is included within the Unresolved Issues" (Stipulation, § III.C) and separately addressed herein at Finding and Conclusion No. 28. Public Staff witness Floyd explained that the Public Staff has historically supported and continues to support, the Summer Winter Peak and Average (SWPA) methodology. Tr. Vol. 23, p. 54. The Public Staff, however, does not object to the Company's use of the SCP, for purposes of this proceeding, because the differences between the per books calculations of revenue requirement between the SCP and SWPA methodologies is immaterial on a jurisdictional basis. Id. at 55.

CUCA witness O'Donnell agreed that the SCP allocation methodology "is appropriate for use in the Company's cost of service study in this proceeding." Tr. Vol. 18, p. 117. Witness O'Donnell stated that since DEC's system is historically summer peaking, the SCP cost of service study "is the most representative model of how the generation system is used in any given year." Id. at 116.

CIGFUR III witness Phillips also agreed that the SCP allocation methodology "is appropriate for use in the Company's cost of service study in this proceeding." Tr. Vol. 26, p. 257. Witness Phillips testified that the SCP allocation methodology "properly allocates cost responsibility to customer classes and, if rates are designed consistent with cost of service, minimizes the need for new generating capacity consistent with DEC's load management goals by sending correct price signals." Id. Kroger also supports the use of the SCP allocation methodology, and witness Higgins testified that the method "allocates production demand and transmission costs to jurisdictions and customer classes based on each group's contribution to the system's highest peak demand, which has historically occurred in summer months." Tr. Vol. 4, p. 500.

The Commission finds and concludes that SCP is the appropriate cost allocation methodology for purposes of this proceeding, subject to the provisions of the Stipulation. Upon consideration of all of the evidence in this proceeding, including the Stipulation upon which the Commission places significant weight, the Commission approves use of the SCP cost allocation methodology to set the Company's base rates in this proceeding.

In arriving at its conclusion, the Commission finds that having the necessary generation and transmission resources to meet the Company's summer peak (plus an appropriate reserve margin) is an essential planning criteria of the Company's system. Under cost causation principles, therefore, all customer classes should share equitably in the fixed production and transmission costs of the system in relation to the demands they place on the system at the peak. As discussed and supported in DEC's integrated resource plans, the Commission also recognizes the Company's shift to winter capacity planning. This change will require more attention in the Company's next general rate case. The Kroger Co. in its post-hearing Brief stated that "[i]f the Commission determines that the winter peak should also be considered in the allocation of production demand costs, an allocator based on the average of the single highest summer and single highest winter coincident peaks may also be appropriate." See Post-Hearing Brief of the Kroger Co., p. 7. The Commission concludes that DEC should file annual cost of service studies based on Winter Coincident Peak as well as the SCP and SWPA methodologies. In its next general rate case, the Company shall prepare cost of service studies based on each of these methodologies.

Although the Public Staff has traditionally supported the SWPA methodology, it is not unreasonable for the Stipulating Parties to have agreed to the use of SCP in this proceeding. Further, the Commission notes that the difference in the retail revenue requirements between the SCP and SWPA methodologies is immaterial on a jurisdictional basis.

The Commission finds and concludes that, for purposes of this proceeding, the Company may use the SCP methodology for allocation between jurisdictions and among customer classes under the provisions of the Stipulation and that the provisions of the Stipulation regarding cost of service methodology are just and reasonable to all parties in light of all the evidence presented.

Minimum System

The Company used a minimum system study to allocate distribution costs among customer classes. The Public Staff does not oppose the Company's cost of service study and allocation methodology for purposes of settlement. NCSEA witness Barnes objects to the use of a minimum system study to allocate costs to customers. Tr. Vol. 20, pp. 74-95. Moreover, witness Barnes also criticizes the specific methodology used by the Company, which he argues inflates the size and cost of the minimum system and increases the portion of the distribution system classified as customer-related. Tr. Vol. 20, p. 94-95.

Witness Hager explained that DEC's minimum system study allowed DEC to classify the distribution system into the portion that is customer-related (driven by number of customers) and the portion that is demand-related (driven by customer peak demand levels). Tr. Vol. 19, p. 35. The methodology behind the Company's minimum system study allows DEC to assess how much of its distribution system is installed simply to ensure that electricity can be delivered to each customer, regardless of the customer's frequency of use. Id. at 36. Witness Hager testified that "[w]ithout the minimum system, low use customers could easily avoid paying for the infrastructure necessary to provide service to them which is counter to cost causation principles." Id. She further explained that the methodology used by the Company is consistent with the guidance regarding allocation of distribution costs provided in the NARUC Cost of Service Manual. Id. at 37.

Witness Hager also explained that while the NARUC Cost of Service Manual suggests two methods of allocation, both of these methods identify a portion of FERC distribution asset accounts 364 to 368 as customer-related and a portion as demand related. Id. at 38. Therefore, witnesses Barnes' and Wallach's suggestion that all of the costs charges to accounts 364 to 368 should be allocated based on demand is inconsistent with the guidance provided in the NARUC Cost of Service Manual. Id.

On cross-examination by counsel for NCSEA, witness Hager testified regarding the Company's long history of using the minimum system method, stating that "the minimum system study has long been used in the cost of service study to develop the customer-related costs that are then passed to rate design and are the basis of rates that are ultimately approved by the Commission." Id. at 138-39. The Company "filed minimum system study results in every rate case for a long time" and the Commission "has approved the results of that." Id. at 143.

In response to questioning from Commissioner Clodfelter, witness Hager testified about the different variations of the minimum system method used by DEP and DEC. Tr. Vol. 20, pp. 27-29. Witness Hager explained that DEP determines the cost of constructing a minimum system configuration using today's costs and the cost of constructing a standard configuration in today's costs, and applies that ratio to the balance of plant account. Id. at 28. Alternatively, DEC calculates the current cost for a minimum size system and then applies a Handy-Whitman Index to adjust to book costs. Id. at 29. She noted, however, that while the methods differ, "they both have the same ultimate goal" and "get you back to the same place." Id. at 28, 30.

In its post-hearing Brief, NCSEA states that "the minimum system analysis is flawed." See NCSEA's Post-Hearing Brief, p. 37. NCSEA states that the minimum system methodology "assumes that some costs of the shared distribution system are effectively incurred solely for the purpose of connecting each customer and that these costs should therefore be classified as customer-related." Tr. Vol. 20, pp. 75-76. In effect, the minimum system methodology "double counts" demand-related costs because a minimum system is still capable of serving some level of demand. Id. at 76.[1]

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[1] See also, Tr. Vol. 19, p. 36 ("But if someone, for whatever reason, wants electricity to light a single 100-Watt light bulb, that customer will require distribution assets such as poles and conductors and transformers to deliver that electricity."). NCSEA notes that, while small, a single 100-watt light bulb would nonetheless impose demand on the grid. See also, Official Exhibits, Vol. 20 (NCJC, et al., Hager/Pirro Cross Exhibit 1) ("Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution

Furthermore, NCSEA states that the Company's modified minimum system methodology does not examine actual costs, but rather defines costs for specified components and extrapolates those costs across the Company's system. Id. at 86. In the case of poles and conductors, this results in more items being included in the minimum system study than are actually on the Company's system and results in a negative assignment for these components in the demand charge. Id. at 87. Further, NCSEA states that the Company's modified minimum system methodology contains flaws in its analysis of poles and structures, overhead conductors, line transformers, and service drops. Id. at 90-94.

The Commission is not persuaded by the evidence presented in this docket that the minimum system analysis employed by the Company is flawed in a way that precludes the Commission from accepting it as appropriate for cost allocation in this proceeding. However, the Commission gives some weight to NCSEA witness Barnes' argument that "[t]he Commission should reconsider its past acceptance of this method for the allocation for distribution costs, and disregard the results as a consideration in rate design." Tr. Vol. 20, p. 95. Witness Barnes stated in his testimony that "Many states confine the definition of customer costs to those costs that are directly attributable to a customer, such as metering and billing, excluding portions of the distribution system shared by multiple customers. A report commissioned by the National Association of Regulatory Utility Commissioners (NARUC) found that this basic customer method (100% demand for shared distribution facilities and 100% customer for meters and services) was the most common approach at the time of the report. There are a number of methods for differentiating between the customer and demand components of embedded distribution plant. The most common method used is the basic customer method, which classifies all poles, wires, and transformers as demand-related and meters, meter-reading, and billing as customer-related. This general approach is used in more than thirty states.[1] Tr. Vol. 20, p. 79.

Further, witness Barnes stated in his testimony that:

> [i]t is not clear to me that the Commission has recently delved into the details of the different methodologies used by North Carolina utilities in conducting their minimum system studies. In fact, significant differences in methodology are apparent to me based on my review of the studies performed by DEP, DEC, and Dominion Energy North Carolina (Dominion). For instance, in its 2016 general rate case, Dominion classified only 31.08% of secondary poles in FERC Account 364 as customer related [in its most recent rate case.][2] DEP classified 95.9% of

method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.").

[1] F. Weston, et al., Charges for Distribution Service: Issues in Rate Design, p. 19, Regulatory Assistance Project (2000), available at http://pubs.narus.org/pub/536F0210-2354-D714-51CF-037E9E00A724.

[2] Application of Virginia Electric and Power Company, d/b/a Dominion North Carolina Power, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, Docket No. E-22, Sub 532 (March 31, 2016) DNCP Form E-1, Item 45F, p. 121.

secondary poles in FERC Account 364 as customer related in its most recent rate case.[1]

Tr. Vol. 20, pp. 82-83.

According to witness Barnes, DEC effectively classifies all shared secondary and primary poles in FERC Account 364 (as well as conductors in FERC Account 365) as customer-related. This is visible in the Company's COSS in the form of negative values for demand-related plant in service for FERC Accounts 364 and 365.[2] The negative values arise because the Company's calculated minimum system is larger than the actual FERC Account balance after removing direct assignments, which necessitates an adjustment. The true-up adjustment effectively results in a demand-related component of zero and a customer-related component of 100%. Similar differences are evident for other distribution Accounts, contributing to a wide range of estimates of residential customer units costs. Id.

The Commission recognizes that any approach to classifying costs has virtues and vices. It is important to effectively address issues such as those discussed by witness Barnes while at the same time recognizing the Company's substantial projected investments in its Power Forward programs. Just considering the grid modernization programs alone suggests that distribution system cost allocation among customer classes will take on heightened importance in future rate cases. The implications of using a suboptimal methodology or incorrectly applying an otherwise acceptable methodology, could be significant in the future. The Commission concludes that a more focused and explicit evaluation of options for distribution system cost allocation and an assessment of the extent to which any single allocation methodology is being consistently applied by the utilities is warranted. Therefore, the Commission directs the Public Staff to facilitate discussions with the electric utilities to evaluate and document a basis for continued use of minimum system and to identify specific changes and recommendations as appropriate. If the Public Staff ultimately recommends an alternative approach to minimum system as a result of this review, then the support for that position should be clearly defined. The Public Staff shall submit a report on its findings and recommendations to the Commission no later than the end of the first quarter of 2019 in a new, generic electric utility docket to be established by the Chief Clerk for this purpose.

Upon consideration of all the evidence in this docket, including the Stipulation, the Commission approves DEC's use of the minimum system methodology for cost allocation in this proceeding. The Commission places significant weight on the testimony of Company witness Hager regarding the Company's long history of employing the minimum system method and this method's alignment with cost causation principles. The Commission finds that the Company's use of the minimum system method for cost allocation in this proceeding is just and reasonable to all parties in light of all of the evidence presented.

[1] Duke Energy Progress, LLC's response to NCSEA Data Request No. 10-20, Attachment B, Docket No. E-2, Sub 1142 (detailing customer and demand percentages by FERC Account).

[2] DEC Form E-1, Item 45D, p. 5.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 29

The evidence supporting this finding of fact and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony of Public Staff witness Boswell, the rebuttal testimony of DEC witness Doss, as well as the entire record in this proceeding.

As part of its filing in this case, the Company submitted a lead-lag study that was performed in 2010 using fiscal year 2009 data. Tr. Vol. 12, pp. 50, 55. Public Staff witness Michelle Boswell commented that a fully updated lead-lag study should have been completed for this case, and recommended that the Commission direct the Company to prepare and file a lead-lag study in its next rate case. Tr. Vol. 26, p. 602. In his rebuttal testimony, DEC witness Doss stated that the Company agrees with Public Staff witness Boswell's recommendation and testified that DEC will prepare and file an updated lead-lag study as part of its next rate case application. Tr. Vol. 12, p. 55.

The Stipulation incorporates the Company's agreement to file an updated lead-lag study in its next rate case. Stipulation, § IV.D. No intervenor took issue with this provision of the Stipulation. Accordingly, the Commission finds and concludes that, consistent with Section IV.D of the Stipulation and in light of all the evidence presented, DEC shall prepare and file an updated lead-lag study in its next general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 30

The evidence supporting this finding of fact and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

Company witness Pirro provided testimony regarding the Company's proposed changes to rate design. Witness Pirro's direct testimony focused on DEC's major proposed rate design initiatives, including:

(1) Basic Facilities Charge (BCF) The Company proposes the BFC for all rate classes, with the exception of OPT-V, be set to recover a percentage difference between the current rate and the customer-related cost incurred to serve these customer groups. Tr. Vol. 19, p. 57. Witness Pirro explained that this approach was taken because current rates significantly understate the current cost of service related to the customer component of cost. Id. The Company's recommendation reduces subsidization while minimizing the rate impact on low usage customers. Id. A comparison of the current and proposed BFCs for each rate class is provided in Pirro Exhibit No. 8.

(2) Residential Rates. Witness Pirro explained that the Company has not proposed any major structural changes to its residential rates. The Company, however, has increased the discount available to customers taking service under Rate RS and Rate RE and receiving Supplemental Security Income through the Social Security Administration and who are blind, disabled, or 65 years of age or over. Id. at 61.

The Company also proposes to discontinue Residential Water Heating Service Controlled/Sub Metered Schedule. Id. at 72-73.

(3) General and Industrial Rates. Witness Pirro explained that other than revisions to the rate to collect the revised revenue requirement, the Company has not altered the overall structure of Rate LGS, Rate SGS, and Rate I, service to large general service, small general service, and industrial customers, respectively. Id. at 62. The Company proposes to increase the incremental demand charge for Rate HP to $0.5994 per kW. Id. at 63.

In Section IV.E of the Stipulation, the Stipulating Parties agreed to implement the rate design proposed by Company witness Pirro within in his direct testimony, except for the amount of the BFC which was an unresolved issue and addressed separately in Finding and Conclusion No. 34 herein. Additionally, the Company entered into the Lighting Settlement with NCLM, Concord, Kings Mountain, and Durham, which resolved certain outdoor lighting issues raised by intervenors in this docket. The Public Staff does not object to the Lighting Settlement.

Several intervenors provided testimony on various rate design issues in this proceeding, as discussed below. Having considered the testimony and exhibits of all of the witnesses and the entire record in this proceeding, the Commission makes its findings and conclusions on each of these issues as set forth below:

AMI Enabled Rates

EDF witness Alvarez criticized the lack of detail in the Company's Application regarding time varying rate offerings that the Company plans to implement in conjunction with AMI. Tr. Vol. 26, pp. 321-27. Company witness Pirro responded that "[i]t would be premature to offer a specific rate design before the infrastructure to support the design is available." Tr. Vol. 19, p. 88.

Additionally, EDF witness Alvarez testified about various AMI-enabled services that he argues offer significant customer and environmental benefit potential. See, e.g., Tr. Vol. 26, pp. 322-27. Company Witness Pirro responded that the Company will consider new rate designs after full AMI deployment, which is expected by mid-2019. Tr. Vol. 19, p. 87. As the Company continues deployment of AMI and begins implementation of new billing infrastructures, the Company will evaluate all potential future rate designs, including dynamic rate designs, and will assess the approach or combination of approaches that cost-effectively meets customer interests and demand response objectives. Id. Witness Pirro also responded to witness Alvarez's suggestion that a collaborative would be beneficial in developing time-varying rate designs, by reiterating that the Company highly values customer input in evaluating both current and future rate designs. Id. at 88. He explained that the Company routinely discusses its rate design with members of the Public Staff and customers, and that it is preferable that such input be received on an on-going basis, rather than awaiting a group meeting to be certain this guidance is considered in the decision-making process with respect to future rate designs and requirements for supporting infrastructures. Id.

Witness Pirro further explained why it would be premature to offer a specific AMI-enabled rate design in this proceeding. Id. In addition to the fact the AMI technology and new billing system infrastructure has not been implemented yet, he testified that it is important to evaluate each rate design in conjunction with other demand response options that seek to shift customer consumption. Id. He explained that all customer options need to be evaluated to achieve the most dependable load response at the lowest cost to customers. Id.

Public Staff witness Floyd testified that the Public Staff's support of the Company's AMI deployment is predicated on maximizing benefits to the customers. Tr. Vol. 23, p. 90. Witness Floyd noted that the Company has committed to develop new and innovative rate designs, which should contribute toward maximizing customer benefit. Id.

The Commission agrees that it is premature to offer specific AMI-enabled rate designs in this proceeding since the infrastructure underlying such rate design is not yet available. The Commission concludes, however, that it is appropriate for DEC to evaluate new rate designs that will, among other things, allow ratepayers in all customer classes to use the information provided by AMI to reduce their peak time usage and to save energy.

TOU or Critical Peak Pricing Rates

NCLM witnesses Hunnicutt and Coughlan testified that the Company should provide additional time-of-use (TOU) and critical peak pricing (CPP) dynamic pricing options for customers. Tr. Vol. 8, pp. 119-43; Tr. Vol. 26, p. 373. The City of Durham stated in its post-hearing Brief that it joins with the NCLM to ask the Commission to order DEC to develop proposals for effective time-of-use and critical peak pricing rate designs which encourage energy efficiency, and provide that information to ratepayers as soon as possible. Witness Hunnicutt testified generally that DEC "should find additional ways through its time-of-use rate designs to encourage and incentivize conservation" and "should provide additional data regarding energy usage to . . . customers on time-of-use rate schedules." Tr. Vol. 26, p. 378. Witness Coughlan testified in more detail regarding the Small General Service Time of Use (SGST) rate and CPP rate option studies, the Peak Time Credit (PTC) Rider pilot, and the smart grid project. Tr. Vol. 8, pp. 121-40. Witness oughlan advocates for the reintroduction of the SGST rate with lower kW and kWh charges, a TOU rate, a CPP rate, a SGS-TOUE rate, the OPT-E rate, and other dynamic pricing options. Id. at 105, 142-43.

Witness Coughlan testified that TOU and CPP dynamic pricing rates can provide a societal benefit. Id. at 119. These rates incent customers to reduce their peak demands and energy consumption during peak periods. Id. This stabilizes demand and creates significant savings for DEC and all customers. Id. While witness Coughlan acknowledged that DEC currently offers the OPT-V rate, he claimed that this TOU rate is not applicable for most customers, who have a load factor of less than 51%. Id. at 120.

Witness Coughlan also discussed the SGST and CPP rates that the Commission ordered the Company to offer on a pilot basis in Docket No. E-7, Sub 1026. Id. at 121-38. Upon conclusion of the pilot period, the Company decided to terminate these rates. Id. at 127. Ninety percent of the customers who participated in the SGST rate pilot program lost money compared to being served on their previous rate. Id. at 128. Witness Coughlan maintained that the SGST rate pilot was unsuccessful because the kW and kWh charges were too high. Id. He argued that if the SGST rate were reintroduced with lower kW and kWh charges, many customers could and would take advantage of the rate. Id. at 129.

DEC, however, terminated the SGST pilot rate, citing "below average acquisition rates and limited performance feedback available to customers." Id. at 127. Customer participation in the SGST pilot rate was low. Id. at 129-30. Witness Coughlan argued that with more time and more marketing efforts, participation would increase. Id. at 130. Moreover, without smart meters available to all customers served by the pilot rates, the Company was not able to provide the rate comparison data that customers wanted. Id. at 130-31; 137-38.

Witness Coughlan asserted that DEC is in a position to implement TOU and CPP rates now, and that municipal jails, parks/recreation facilities, and water and sewer treatment facilities, in particular, could benefit from these pricing options. Id. at 142.

In its post-hearing Brief, NCLM stated that "[t]he Commission should order DEC to develop proposals for new and innovative time-of-use and critical peak pricing rate designs and prepayment options before the next rate case, and receive input from customers." See Post-Hearing Brief and Partial Proposed Order of NCLM, p. 11.

In his direct testimony, Company witness Pirro explained that DEC was not proposing any innovative peak time pricing rate designs or offering real time price signals in this proceeding. Tr. Vol. 19, p. 58. Witness Pirro explained that DEC continues to review and analyze rate designs that offer customers opportunities to respond to price signals to achieve a lower cost for electric service. Id. As described in the testimony of witness Hunsicker, the Company is upgrading its billing system infrastructure to better support these types of designs. Id. Also, as explained by Company witness Schneider, DEC is in the process of deploying AMI that will provide the level of data that is required to bill these innovative designs. Id. at 58-59. Witness Pirro explained that the Rate Design Team is working closely with billing and metering projects to ensure that they will support the types of rate designs that customers will need in the future. Id. at 59. Witness Pirro also noted that the Company presently offers time-of-use rate designs to various customer classes to encourage load shifting and also offers several DSM programs to control customer appliances to aid in reducing system peak demands. Id. Moreover, on cross-examination by counsel for NCLM, witness Pirro explained that as the Company "gets closer to full AMI rollout and implementation of the billing systems, we will continue to work with the Public Staff and try to come to a common . . . ground on future price offerings and trying to balance that with maybe some demand response programs to achieve overall cost effectiveness." Id. at 203.

Based on the results of the pilot rates implemented in Docket No. E-7, Sub 1026, the Commission is not persuaded that DEC should be required to offer any additional TOU or CPP dynamic pricing rate options at this time. However, the Commission finds and concludes that DEC should, within six months of the date of this Order, file in this docket the details of proposed new time-of-use, peak pricing, and other dynamic rate structures, as detailed in the AMI portion of this Order.

OPT-V Rate

CIGFUR III witness Phillips criticized DEC's Optional Power Service Time of Use (OPT-V) rate schedule. Tr. Vol. 26, p. 258. While witness Phillips agreed that the Company's proposed demand charges for the OPT-V rate class were appropriate, he argues that the present and proposed energy rates are significantly higher than the unit costs reflected in DEC's cost of service study. Id. He stated that the energy charges for OPT-V customers are 30-60% above the unit costs in the Company's cost of service study, and argued that these charges should be reduced to better reflect actual energy costs. Id. at 268. Witness Phillips recommended that any approved reduction to the Company's requested revenue increase for the OPT-V class be used to reduce the proposed energy rates, particularly for Transmission Service and Large Primary Service customers. Id.

On cross-examination by counsel for CIGFUR III, witness Pirro explained that the Company did not agree with witness Phillips' recommendation to adjust the OPT-V rate design to move the energy charges closer to unit cost. Tr. Vol. 19, pp. 115-24. Witness Pirro explained that the OPT-V "rate and pricing structure has been very successful from the onset. [DEC has] had very positive feedback from [its] commercial/industrial groups during customer meetings, and they . . . have been very happy with the pricing structure. And . . . during those customer forum groups, [the Company has] had no complaints." Id. at 120. He added that OPT-V is a relatively new rate design and the Company has received positive feedback regarding this rate from both external and internal customers through its large account management and economic development teams. Id. at 124.

In addition to the Company having received very positive customer feedback regarding the OPT-V rate, witness Pirro explained that the Company must "look at all the pricing components in order to send appropriate price signals." Id. at 123. One such factor is marginal cost pricing, and witness Pirro testified that reducing energy rates below those levels would not be justifiable. Id. at 122. He reiterated that it is inappropriate to adjust the energy charge in isolation, and that the Company must "look at all of the pricing components as a whole, the customer charge component, the demand and energy, and you have to balance those to send the appropriate price signal." Id.

The Commission finds and concludes that the Company's proposed OPT-V rate is just and reasonable in light of the evidence presented. The Commission, therefore, rejects witness Phillips' recommendation to reduce the proposed energy rates for Schedule OPT-V on the grounds that adjusting one pricing component without consideration of all pricing factors is inappropriate. It is appropriate to consider all pricing components, including marginal cost pricing, customer charge, as well as demand and energy charge, and balance these various components in order to set rates that send an appropriate price signal to customers. Applying that framework, the Commission finds and concludes that the Company's proposed OPT-V rate, including the proposed energy rate, strikes an appropriate balance of pricing factors and sends the correct price signal to customers.

Outdoor Lighting

Company witness Cowling testified regarding the proposed changes to DEC's outdoor lighting rate schedules. First, the Company re-evaluated the outdoor lighting transition fees charged to customers who move from metal halide (MH) and high pressure sodium (HPS) to light emitting diode (LED). Tr. Vol. 26, p. 161. The Company is proposing to lower the transition fees to balance the actual take-rates while protecting the rate class from premature retirement of assets. Id. Witness Cowling explained that the Company has charged a transition fee for customers who voluntarily chose to upgrade standard, decorative, and/ or floodlight outdoor lighting fixtures from MH or HPS to LED. Id. at 162. The purpose of the transition fee was to appropriately reflect the remaining book value of the MH and HPS lights being replaced and hence slow the early retirement of installed assets to avoid adverse impacts on lighting rate base. Id. While the fees have successfully allowed customers to switch to LED technology while minimizing the impact of the transition on other lighting customers, the Company, based on its transition experience to LED technology, now recommends calculating transition fees based on a revised assumption regarding the rate of replacement of fixtures. Id. at 162-63. DEC proposes to reduce the fee to transition from a standard MH or HPS fixture to an LED fixture from $54 to $40 on Schedules GL and PL, and from $78 to $57 on Schedule OL. Id. at 163. The Company proposes to reduce the fee to transition from a standard MH floodlight or HPS floodlight fixture to an LED and/or LED floodlight fixture on Schedule FL from $142 to $112. Id. Cowling Direct Exhibit 1 outlines the current and proposed transition fees on Schedules OL, GL, PL, and FL.

Second, the Company proposes to proactively replace mercury vapor (MV) lights with LED lights on Schedule PL (governmental customers). Id. at 161. Currently, DEC is authorized to upgrade MV fixtures to LED technology upon failure on Schedule PL. Id. at 165. In Docket No. E-7, Sub 1114, DEC received Commission approval to proactively upgrade standard MV fixtures to LED on Schedule OL (private area lights) by no later than December 31, 2019. Id. at 165-66. Under the current approach of only replacing MV fixtures at failure and assuming that customers do not choose to upgrade voluntarily, at the current failure rate of approximately 4.6% per year it will take approximately 22 years to upgrade all of the MV fixtures in North Carolina. Id. at 166. A proactive strategy allows the Company to more rapidly phase-out obsolete MV fixtures in the DEC service territory. Id. Also, it is more cost-effective for the Company to replace the MV lights proactively grouping the work geographically, rather than reactively one-by-one as they fail. Id. The Company is proposing that the Commission approve DEC's proactive replacement on Schedule PL to begin in 2020 and with work completed by 2023. Id. at 167. This gives governmental customers adequate time to budget for the conversions, and also gives the Company adequate time to complete the proactive replacement underway on Schedule OL by the current December 2019 goal. Id.

Lastly, the Company is proposing several revisions to the outdoor lighting schedules to improve administration, including proposals (1) to close Schedule NL, which is a pilot tariff designed primarily to introduce LED technology, (2) to discontinue Schedule FL and merge it into Schedules OL and GL, and (3) to increase the contract term on Schedule OL for standard products from one year to three years. Id. at 161, 169-70. The Company incurs a significant capital investment when installing new outdoor lighting assets and these costs are not recovered if lighting service is discontinued after one year. Id. at 169.

Witness Cowling also explained in his direct testimony that the Company has participated in semi-annual meetings to address issues of interest to North Carolina municipalities and to specifically address lighting issues. Id. at 168. The Company states these meetings are valuable and plans to continue the outdoor-lighting specific dialogue that has been established between municipalities and the Company by meeting with the NCLM and governmental customers on as-needed basis. Id. at 168-69.

Public Staff witness Floyd responded to the Company's proposed outdoor lighting schedules by making three recommendations. First, Witness Floyd explained that the Public Staff agrees with DEC's proposed transition fees for LED service, testifying that the fees "reasonably balance the desire of customers for LED service, with the need to transition lighting in an orderly manner, while minimizing the adverse impact of stranded costs on the remaining lighting class." Tr. Vol. 23, p. 68. The Public Staff, however, states that the Company should consider providing an extended payment option to customers, such as municipalities who desire LED service, but struggle with budgeting issues that prevent their participation. Id. at 69.

Second, witness Floyd testified that the Company's proposal to accelerate the conversion of MV fixtures to LED served under Schedules OL and PL is reasonable, but recommends that the Company address the rates of return (ROR) for the lighting class in order to mitigate the increase in the cost of the conversion. Id. at 72. Witness Floyd recommended that the Company reduce its rates for Schedules FL, GL, OL and PL such that the resulting RORs are within 10% of the overall ROR for the North Carolina retail jurisdiction. Id. at 72-73. Witness Floyd also recommended that the Commission require the Company to file semi-annual reports on the status of its MV replacement program. Id. at 73.

Witness Floyd testified that the Public Staff does not object to the Company's proposals to close Schedules FL and NL. Id. at 74. Witness Floyd also testified about the alignment of rates for the same fixtures served under Schedules GL and PL. Id. at 74-76. Witness Floyd noted that Schedule GL and PL charge different rates for the same fixture, and that the only difference between the two schedules is the length of time a customer has been served under one schedule versus the other, which is not a valid reason for differing rates. Id. at 76. As such, he recommends that the Commission require the Company to continue to meet with municipal customers to evaluate changes to Schedules PL and GL that would make the rates for individual fixtures (LED and non-LED) served under Schedule GL the same as for Schedule PL. Id. at 76-77. He also recommends that the Company work with municipalities to develop a proposal to consolidate Schedules PL and GL in a future proceeding. Id. at 77.

NCLM was the only other intervenor to provide testimony regarding outdoor lighting rate design. NCLM witnesses Coughlan, Fisher and Watkins all presented testimony on various outdoor lighting issues.

Witness Coughlan recommended several changes to the GL rate schedule. Witness Coughlan advocated for the elimination of the transition fees for replacing HPS and MH luminaires with LED luminaires. Tr. Vol. 8, p. 104. Mr. Coughlan noted that the purpose of the transition fee was to appropriately reflect the remaining book value of the MH and HPS lights in order to avoid adverse impacts on the lighting rate base. Id. at 107. However, he argued, that the Company should actively promote the transition to LED lighting rather than discourage it through fees because LEDs are better for customers and the environment. Id. at 108. Witness Coughlan argued that DEC should not be compensated for the transition to new technology. Id.

Alternatively, he suggested that DEC could offset the loss in book value by requiring all lighting customers to pay for it, instead of only those customers switching to LED luminaires. Id. at 109.

Witness Coughlan advocated for establishing a fairer rate for municipalities under Rate GL by lowering the proposed rates for LED lighting. Id. at 110. The proposed ROR for Rate GL is 27.23%, compared to 7.98% for total retail rates. Id. at 109. Witness Coughlan noted that, overall LED lighting costs less than HPS lighting (e.g., installation labor costs, maintenance labor costs, maintenance equipment costs, energy costs), but DEC's rates for LED lighting "are significantly higher" than the rates for HPS lighting. Id. at 111-14. He asserted that lower maintenance labor costs, maintenance equipment costs, and energy costs for LED lighting should be, but are not, accurately accounted for in the proposed rates. Id. at 115-16. Witness Coughlan recommended that the costs for lighting under Schedule GL be adjusted such that on a cost/kWh consumed basis, the rates for LED lighting are equal to or lower than the costs of HPS lighting. Id. at 104.

Witness Coughlan also testified that, to the extent the transition fee is not eliminated, the Commission should only apply such a fee where a municipality seeks to convert all HPS lights to LED lights at the same time. Id. at 118. Witness Coughlan recommended eliminating the transition fee where an existing HPS light has failed or needs maintenance. Id. He argued that "[t]his approach would save DEC from having to travel to existing HPS lights to perform maintenance work and then making another trip back to the same light a year or two later to replace a recently maintained HPS light with an LED light as part of a mass conversion." Id.

Similarly, witness Watkins testified that the Company's LED transition fees and outdoor lighting rates make it "difficult for [the City of] Burlington and other municipalities to afford a complete conversion to LED lighting" which inhibits these municipalities from "maximizing energy efficiency and prevent crime." Tr. Vol. 26, p. 390. He recommends that DEC should cover the cost of conversions for HPS and MH fixtures as well as MV fixtures. Id. at 391. Likewise, witness Fischer testified that DEC should eliminate the transition fee entirely. Id. at 367. Furthermore, witness Fischer stated that if DEC decides not to charge a transition fee for LED lighting, the rates attributable to LED fixtures should not increase, as proposed in DEC's PL rate schedule. Id. at 390, 367. Witnesses Watkins and Fischer also recommended that if the municipality is required to pay a transition fee to switch to LED lighting, the rates paid for LED street lighting should not increase. Id. at 390, 368. Witnesses Watkins and Fischer testified that the current transition fees and the requirement to shift from Schedule PL to GL rate for conversions create a disincentive for municipalities to convert to LED street lighting. Id. at 391, 368.

These witnesses also noted that the Company is requesting rates for street lighting with a ROR for the GL class of 27.22% and the PL class of 12.20%, which fall outside of the +/-10% band of reasonableness for RORs relative to overall jurisdictional ROR (7.98%). Id. at 392, 368. Finally, witness Watkins testified that the NCLM would like to continue meeting with the Company semi-annually, rather than on an as needed basis as suggested by witness Cowling. Id. at 393.

In response to the intervenors' testimony regarding the Company's transition fees for LED service, witness Cowling explained in his rebuttal testimony that "the Company believes these fees are appropriate, as the Company, consistent with its Commission-approved tariffs, installed HPS and MH fixtures at the request of customers; thus, the prudently incurred stranded costs related to these assets should be recovered from the customer requesting early replacement, rather than burdening the lighting class as a whole." Id. at 173. He further testified that the Company will continue to monitor net book value and in future rate proceedings and seek adjustments accordingly. Id.

Witness Cowling also testified in opposition to witness Coughlan's recommendation that transition fees be eliminated for any HPS failure. Id. at 174. He explained that as stated in Witness Coughlan's testimony, HPS lamps last approximately six years, which is far less than the HPS fixture. Id. Given the long depreciation periods of HPS fixtures, replacing HPS fixtures after being in service for six years due to a bulb failure without a transition charge would still leave a significant net book value remaining for HPS fixtures. Id.

Witness Cowling agreed with the recommendation of Public Staff witness Floyd, and testified that the Company wants to work with NCLM to evaluate changes to Schedules PL and GL for the purpose of eventually consolidating Schedules PL and GL in a future proceeding. Id. at 177. Witness Cowling also testified that the Company values its partnership with all of the communities it serves and NCLM and will continue to meet with NCLM regarding outdoor lighting matters. Id. at 176. The Company has proposed meeting on an as-needed basis to provide more flexibility to meet either more or less often and address issues in a timelier manner as they arise. Id. at 177. The Company has also expressed an interest in attending NCLM's annual meeting to discuss lighting matters, which would minimize travel costs to NCLM members and expand the opportunity for more municipalities to participate in outdoor lighting discussions with the Company. Id.

Witness Pirro testified in response to the intervenors' testimony regarding the ROR for the lighting rates. Tr. Vol. 19, pp. 97-98. Regarding the proposed ROR of 27.23% on Schedule GL, witness Pirro explained that the proposed rates and concomitant return are the result of the application of the same rate design principles that were applied to all other rates proposed in this proceeding. Id. at 97. As noted on Pirro Exhibit No. 4 the current return on this rate schedule is nearly 31%. Id. DEC seeks to achieve rate parity for all of its customer classes; however, rate parity cannot be achieved quickly without some customers experiencing significant rate increases. Id. Thus, DEC has and is applying the principle of "gradualism" as it moves all rate classes closer to a uniform return. Id. While DEC understands witness Floyd's and NCLM witnesses' concerns, it must be recognized that ratemaking is a zero-sum process and costs not recovered from one customer class must be recovered from another customer class. Id. at 97-98. Witness Pirro testified that "DEC is committed to continuing to work with the Public Staff and NCLM in an attempt to resolve their concerns in a manner that is appropriate for DEC's other customers, and acceptable to the Commission, and will allow DEC a reasonable opportunity to recover its Commission-approved revenue requirement." Id. at 98.

Prior to the evidentiary hearing, the Company entered into the Lighting Settlement with NCLM, Concord, Kings Mountain, and Durham, which resolved all of the outdoor lighting issues raised by the NCLM in this docket.[1] The parties to the Lighting Settlement agreed to waive cross-examination of each other's witnesses on the outdoor lighting issues addressed in the Lighting Settlement. Lighting Settlement, p. 6. Moreover, the Public Staff does not object to the Lighting Settlement, (id. at 2), and waived its cross-examination of Company witness Cowling.

The Lighting Settlement provides in pertinent part as follows:

> 1. DEC shall keep the current proposed LED transition fee reduction for HPS luminaires from $54.00 to $40.00, but will evaluate adoption of LED technology and its impact on the transition fees every two years between rate cases and adjust the fees downward if applicable. DEC will eliminate the HPS transition fee on entire fixture failure. Transition fees will not be increased outside of a general rate proceeding. The results of any re-evaluation will be reported to the Commission and be subject of a filing for a fee reduction.
>
> 2. DEC will allow municipalities to spread the billing for transition fees for up to four years without incurring carrying costs, to be billed annually in August.
>
> 3. DEC will combine Rate Schedule GL (Governmental Lighting) and Rate Schedule PL (Street and Public Lighting) to reflect PL pricing as approved by the Commission in its final order in this Docket, effective September 1, 2018 and close Rate Schedule GL. Lights on Schedule GL will be mapped to the rates proposed on PL for inside municipal limits. For Schedule GL lights served underground, DEC will apply underground charges assuming up to 200 feet served from overhead to underground for a monthly fee of $0.87 per month. Additional decorative and/or non-standard charges for poles, fixtures, or underground fees greater than 200 feet will still apply as would be applicable under the currently-identical provision of Schedules GL and PL. This will lower the ROR on the GL rate.
>
> 4. Combining Rate Schedule GL and Rate Schedule PL and not seeking an increase in LED rates in this Docket results in a $1.658 million revenue requirement deficit to DEC. Upon approval by the Commission, the lighting ROR will be reduced to fall within the +/-10% range of the retail average and the resulting revenue reduction ($1.658 million under proposed rates) would be allocated to the other rate classes (RES, GS, I and OPT). The Parties affirm that this Agreement reflects the spirit and intent to continue moving government lighting's ROR closer to the average retail customer ROR.
>
> 5. DEC will maintain current LED prices for GL and PL customers and not seek a rate increase for LED fixtures in this Docket. After September 1, 2018,

[1] The only remaining issues in controversy raised by NCLM in this docket are (1) the impact of the Tax Cuts and Jobs Act on DEC's rates; and (2) TOU and CPP dynamic pricing rate options.

all LED rates applicable to governmental customers will be billed on the PL schedule.

6. For all customer lighting classes, DEC will eliminate the HP'S transition fee if the entire HPS fixture fails. Upon complete fixture failure, unless no comparable LED fixture is available, DEC will replace any standard or non-standard and/or decorative HPS fixture with a comparable LED fixture and the monthly rate for the new fixture will apply. DEC will continue to maintain HPS fixtures and perform minor repairs. DEC will not waive the transition fee for HPS fixtures that are replaced prematurely due to willful damage of the fixture and/or when minor repairs can be performed and the customer choses to voluntarily upgrade to LED.

7. DEC will close HPS to new installations in all lighting class Rate Schedules (PL, GL, and OL) to lessen the impact on the net book value to all lighting. Where the governmental customer requests the continued use of the same HPS fixture type for appearance reasons, DEC will attempt to provide such fixture, and the governmental customer shall be billed in accordance with the applicable provisions on Schedule PL.

8. The Company's floodlight service is currently billed on Schedule FL. In this Docket, DEC requested to close Schedule FL and move the floodlights to either Schedule OL (private customers) or to Schedule GL, (public customers). Effective upon Commission approval, DEC will proceed to add the governmental floodlights to Schedule GL at the proposed rates. Effective September 1, 2018, DEC will move these newly added floodlight from Schedule GL to Schedule PL, including any notations and applicable rates at the same time that DEC transitions the other non-floodlights from Schedule GL to Schedule PL.

9. As of September 1, 2018, governmental customers seeking new non-floodlight service which involves installing a new pole and/or new underground service will pay the current new pole and underground charges on Schedule GL. Currently, a standard wood pole is $6.49 per pole and underground charges begin at $4.62 up to 150 feet. The aforementioned fees will not be applicable to fixtures, poles and underground services for non-floodlights moved from Schedule GL to Schedule PL. Current PL fees for such services will apply unless otherwise modified in a future rate proceeding.

10. When Schedule GL is merged into the new PL, the Company will continue to provide an option for customers to prepay the initial capital costs of poles and underground wiring for products with the tiered rate structure (existing pole, new pole, and new pole underground) as provided for in Paragraph 9. These products will include LEDs and floodlights that are merging from GL to PL with the tiered rate design. Thus, if customers chose to prepay capital costs for the pole and underground wiring, customers will be billed for the existing pole rates accordingly.

11. As part of DEC's proposal to accelerate the conversion of MV fixtures to LED for governmental customers, the Company agrees to file semi-annual conversion progress reports with the Commission as proposed in the Docket testimony of Public Staff witness Jack Floyd. The Company will also provide governmental customer-specific data regarding proactive MV to LED conversions to impacted governmental customers before such work begins, as well as providing information summarizing the benefits of the conversion to LED for each governmental customer.

12. The Company will continue regular meetings with the NCLM and all interested localities at mutually convenient times and locations to discuss outdoor lighting issues.

Lighting Settlement, pp. 2-5.

In light of the parties' testimony and the Lighting Settlement, which the Commission accepts in its entirety and upon which the Commission places substantial weight, the Commission finds and concludes that the Company's proposed lighting rate schedules, as modified by the Lighting Settlement, are just and reasonable.

<u>Standby Service</u>

Standby service is where the Company provides service to customers with customer-owned generation during times when the generation either isn't operating or fails to operate and requires additional capacity and energy to be provided by the Company. Several of the Company's tariffs have some form of standby service. Based on witness Pirro's testimony, the Company developed, since the last rate case, an approach to pricing service to net metering customers with solar generation that was ultimately approved in South Carolina as the result of a collaborative agreement.

Further, witness Pirro testified that the Company has closely monitored developments leading up to House Bill 589 and its subsequent passage into law. There are multiple requirements for the Company to comply with this legislation, including changes to the current net metering tariffs. Witness Pirro noted that the Company's analysis in South Carolina will be useful for this purpose. The Company intends to pursue these changes outside of this general rate proceeding and believes that standby service consideration will be a critical part of that discussion. For the interim, witness Pirro testified that standby service is priced in the same manner as that supported by the Company and approved by the Commission in the last rate case.

Public Staff witness Floyd testified that "[g]iven the Company's proposed continuation of the current structure for standby charges until the net metering proceeding, and the small increase proposed for the rate itself, I consider the Company's proposal to be reasonable at this time." Tr. Vol. 23, p. 65.

The Commercial Group in its post-hearing Brief stated that:

> The Commercial Group opposes the structure of DEC's current and proposed standby service. Tr. Vol. 26, p. 529. However, recent N.C. legislation (Session Law 2017-192) would require DEC and other electric utilities to file new net metering rates that are set such that customer-generators pay their full fixed cost of service (but not more than their cost of service). Accordingly, the Commercial Group is deferring its advocacy on those issues to any upcoming proceedings regarding House Bill 589 compliance.

Id.

The Commission concurs with the Company's position and will address standby charges in an upcoming docket.

Summary with Respect to Rate Design

Based on the testimony of Company witnesses Pirro and Cowling, with consideration of the testimony of witnesses Floyd, Coughlan, Fisher, Hunnicutt, Watkins, Alvarez, and Phillips, as well as the Stipulation and the Lighting Settlement, the Commission finds and concludes that the rate design provisions in Section IV.E of the Stipulation as well as the Lighting Settlement are just and reasonable to all parties in light of all the evidence presented.

The Stipulation states that "[t]o the extent possible, the Company shall assign the approved revenue requirement consistent with the principles regarding revenue apportionment described in the testimony of Public Staff witness Floyd." See § IV.E.1 of Stipulation. Specifically, witness Floyd's testimony stated:

> That any proposed revenue change be apportioned to the customer classes, especially for the lighting class, such that: (a) Class RORs are within a band of reasonableness of ± 10% relative to the overall NC retail ROR; (b) All class RORs move closer to parity with the NC retail ROR; (c) The revenue increase to any one customer class is limited to no more than two percentage points greater than the NC retail jurisdictional percentage increase, with priority given to the percentage increase versus the ROR band of reasonableness; and (d) Subsidization among the customer classes is minimized.

Id.

The Commercial Group presented the testimony of witnesses Chriss and Rosa including a recommendation that "[i]f the Commission determines that the appropriate revenue requirement is less than that proposed by the Company, the Commission should use the reduction in revenue requirement to move each customer class closer to its respective cost of service while ensuring that all classes see a reduction from DEC's initially proposed increases." The Commission concludes that it is reasonable, to the extent possible, for the Company to consider the Commercial Group's recommendation when assigning approved revenue requirements.

Further, the Commission approves DEC's proposal to discontinue the Residential Water Heating Service Controlled/Sub Metered Schedule. The Commission is, however, concerned that discontinuing programs that can be used to effectively clip winter peaks is moving in the wrong direction. This is especially true given the fact that the Company has moved to "winter planning." The Commission noted in its Order accepting 2017 IRP update reports that "DEC's 2017 IRP includes winter DSM resources that are approximately 80 MW less than included in its 2016 IRP Report." See Order Accepting Filing of 2017 Update Reports and Accepting 2017 REPS Compliance Plans, Docket E-100, Sub 147, p. 7. The Commission concludes that additional emphasis on winter DSM resource planning is warranted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 31-33

The evidence supporting these findings and conclusions is contained in the Company's verified Application and Form E-1, and the testimony and exhibits of DEC witnesses Fountain, Simpson, Pirro and McManeus, and Public Staff witnesses Williamson and Boswell and the entire record in this proceeding.

Vegetation Management

Company witness Simpson testified that vegetation management is a critical component of the Company's power delivery operation. Tr. Vol. 16, p. 100. He explained that DEC uses a reliability-based prioritization model to drive its routine integrated vegetation management program. Id. According to witness Simpson, in addition to routine circuit maintenance, there are four other important components to the Company's overall vegetation management approach:

(1) Herbicide spraying of the "floor" of the right-of-way is planned on a periodic basis to control the re-growth of incompatible vegetation in non-landscaped areas and where property owners allow the Company to spray;

(2) Cutting down of "hazard trees" outside of the area normally maintained on a distribution line. The Company implemented this program in 2014 and has been successful in targeting removal of diseased, decayed, or dying trees to preserve the integrity and safety of DEC's lines;

(3) Unplanned work performed at the direction of reliability engineering as a result of outage follow-up investigations or by customer-initiated requests; and

(4) Disciplined vegetation management outage follow-up process tied to a formal internal reliability review process.

Id. at 100-01.

In addition, witness Simpson described how as a result of the Company's worsening trends in SAIDI and SAIFI[1] and the Company's commitment to continue to improve reliability, DEC is enhancing its vegetation management program through a focus on the following areas, all of which require additional funding:

- An increase in the frequency of trimming to stabilize and improve the vegetation management impact on overall reliability performance;

[1] SAIDI and SAIFI are metrics that reflect the averages duration and frequency of power outages.

- Increase frequency of herbicide application where appropriate;
- Evaluate the feasibility of a Tree Growth Regulator program; and
- Continuing other aspects of the current program, such as distribution line "hazard tree" cutting and a disciplined vegetation management outage follow-up process.

Id. at 102-03. As explained by DEC witness McManeus, the Company has included a pro forma adjustment related to an expected $15.8 million increase in system expenditures, or $11.3 million on a North Carolina retail basis,[1] to reflect these enhancements to the Company's vegetation management program. Tr. Vol. 6, p. 264. Witness Simpson testified that this increase in funding will strengthen DEC's vegetation management plan and help maximize the effectiveness of the Company's planned grid improvements. Tr. Vol. 16, p. 103. He added that the Company believes that the additional funding and implementation of its plan, with these enhancements, will benefit customers. Id.

Public Staff witness Williamson testified that the Company initiated its current vegetation work cycle, referred to as the "5/7/9 plan" in 2013. Tr. Vol. 22, p. 43. He explained that the plan represented a change from a reliability-based approach to vegetation management to a cyclical approach. Id. The plan classifies DEC's distribution circuit-miles into three categories, maintained on three independent cycle periods: "Old-urban" – five years; "Mountain" – seven years; and "Other" – nine years. Id. He noted that these cycles were determined from a vegetation growth study conducted by DEC's consultant. Id. He stated that during the first five years of the plan, the Company completed vegetation management on 88% of the target miles. Id. at 44. For this period, he opined that the Company is behind their combined target miles for all categories, thus creating a back-log of approximately 3,752 miles. Id.

Additionally, witness Williamson indicated that when DEC initiated the 5/7/9 plan in 2013, the Company had developed a back-log of approximately 11,000 miles, and that as of January 2018 the current balance of those back-log miles was approximately 10,000 miles. Id. at 45. He contended that the Company would not need to address the 10,000 mile back-log if a proper, cyclical vegetation management program had been in use by the Company prior to 2013. Id. at 46. As a result, Public Staff witness Boswell recommended a pro forma adjustment to vegetation management test year expenses. Tr. Vol. 26, p. 596. The Public Staff's adjustment maintains the reactive, herbicide, and contract inspector program costs at test year actual spending levels, but applies a 7% increase in contractor vegetation management production labor costs. Tr. Vol. 22, p. 45.

Witness Simpson described how the Company performed a vegetation growth study to determine the optimum level of vegetation management for DEC's system, and that the Company used the results of that study to develop the 5/7/9 plan. Tr. Vol. 23, pp. 155-56. According to witness Simpson, the Company's last rate case did not fully fund the plan. Id. at 156. As a result, even though the Company has been spending above the vegetation management amounts included in rates from the last rate case, the Company has only been able to complete

[1] In her December 18, 2017 revised supplemental direct testimony and exhibits, witness McManeus adjusted these amounts to reflect increased labor costs due to higher contractor rates. Tr. Vol. 6, p. 290.

vegetation management on 88% of the planned miles during the five years since the 5/7/9 plan was adopted. Id.

Witness Simpson further stated that the Public Staff's recommended adjustment only took into account a 7% increase in contract rates for 2017 and did not consider that the 5/7/9 plan is still not funded. Id. at 156-57. In addition, he mentioned that the Public Staff did not acknowledge the Company's requested increase for transmission vegetation management. Id. at 158. He also noted that the Public Staff gave no consideration for the 2018 contractor rate increases, given that executed contracts could not be provided until after they were signed on January 24, 2018. Id. at 157. In her second supplemental testimony and exhibits, as well as her rebuttal testimony and exhibits, witness McManeus revised her adjustment to vegetation management expenses to reflect higher contractor rates in recently executed contracts. Tr. Vol. 6, pp. 298, 343. Those contracts resulted in an increase in 2018 rates of 18%. Tr. Vol. 23, p. 157. The revised rates resulted in an increase in production costs of $55.8 million versus the $44.9 million calculated in witness Boswell's schedule. Id. The new contracts also include increases for the demand costs, which are now $2.9 million versus the $2.4 million calculated by witness Boswell. Id. Witness Simpson noted that confirmation of the contractor increases was not available until after Public Staff filed its testimony, and that this is a key piece of information that the Commission should take note of and that may influence Public Staff's view. Id. at 155.

Witness Simpson concluded that given prudent increases in spending, known and measurable increases in contractor rates, and the commitment of the Company to its vegetation management cycles, it is reasonable for the Commission to approve its request to increase funding for vegetation management. Id.

The Stipulation provides that the Company should be allowed to recover distribution vegetation management costs in an annual amount of $62.6 million on a total system basis. Stipulation, Section III.A. For the purpose of complying with the Company's current vegetation management program, the Company committed to eliminate completely the 13,467 miles of Existing Backlog as of December 31, 2017 within five years after the date rates go into effect in this proceeding, and the Company additionally committed to spending the necessary amount on an annual basis to trim its annual target distribution miles under its 5/7/9 Plan. In addition, DEC agreed to provide a report annually to the Commission with the following information: (1) actual 5/7/9 and Existing Backlog miles maintained in the previous calendar year; (2) current level of Existing Backlog miles; (3) vegetation management maintenance dollars budgeted for the previous calendar year for 5/7/9 and Existing Backlog; and (4) vegetation management maintenance dollars expended in the previous calendar year for 5/7/9 and Existing Backlog. The Company further agreed that any accelerated amount of expenditures to eliminate the Existing Backlog miles shall not be used to increase the level of vegetation management expenses in future proceedings, but shall not prohibit the Company from seeking adjustments for vegetation management contractor rate increases. The Commission finds that this provision of the Stipulation represents a reasonable compromise of this disputed issue. The Commission, therefore, finds and concludes that DEC's and the Public Staff's agreement relating to vegetation management, as set forth in Section III.A of the Stipulation, is just and reasonable to all parties in light of all the evidence presented.

Quality of Service

Witness Fountain provided testimony relating to the Company's service quality and ways in which the Company is working to enhance the customer experience. Tr. Vol. 6, p. 186. Witness Fountain noted that customer satisfaction (CSAT) is a key focus area for DEC. Id. The Company's CSAT program includes both national benchmarking studies and proprietary transaction and relationship CSAT studies. Id. Witness Fountain explained that the Company leverages results from these studies to drive improvement to processes, technology, and behavior, in order to improve CSAT. Id. He indicated that DEC's J.D. Power's Electric Utility Residential Study scores are trending up, with the Company being among the most improved in the 2017 study, and closing the gap toward top quartile performance. Id.

Witness Fountain testified that DEC measures overall customer satisfaction and perceptions about the Company via its proprietary relationship study, the "Customer Perceptions Tracker." Id. Random surveys are taken from residential and small/medium business customers, and all large business electric customers, to better understand their customer experience with Duke Energy and overall perceptions of the Company. Id. He stated that Duke Energy North Carolina Residential satisfaction scores are up over ten points on average from 2013, with recent trends even higher. Id. at 187.

As explained by witness Fountain, in addition to its relationship study, DEC utilizes Fastrack, the Company's proprietary transaction study, to measure overall customer satisfaction with the Company's operational performance (i.e., responding to and resolving customer service requests). Id. Each year, thousands of interviews are conducted with DEC customers by a third-party research supplier upon the completion of the customers' service request. Id. The survey questions cover the entire experience, from the time the customer picks up the phone to contact the Company, until the issue is resolved. Id. Witness Fountain indicated that analysis of these ratings helps to identify specific service strengths and opportunities that drive overall satisfaction and to provide guidance for the implementation of process and performance improvement efforts. Id. Through mid-2017, roughly 85% of DEC's residential customers expressed high levels of satisfaction with these key service interactions (Start/Transfer Service, Outage/Restoration, Street Light Repair, etc.). Id.

Witness Fountain testified that in 2016, Customer Satisfaction continued as one of a select number of goals included in the annual incentive compensation plans for DEC employees. Id. According to witness Fountain, by connecting customer satisfaction directly to compensation, each employee is invested in improving and maintaining high customer satisfaction for all Duke Energy utilities, including DEC. Id. at 187-88. Results are monitored at the enterprise level, state level, and by customer segment, so problems can be identified and corrected. Id. at 188. This also allows the Company to identify and apply best practices across all Duke Energy jurisdictions. Id.

Finally, witness Fountain stated that the Company continues to enhance its customer service practices to address language, cultural, and disability barriers. Id. Among other accommodations, the Company's customer service center offers customer service and correspondence in Spanish, handles calls from TTY devices (text telephones), offers bills in Braille, and accepts pledges to pay from social service agencies. Id.

Public Staff witness Williamson also provided testimony regarding DEC's quality of service. Tr. Vol. 22, pp. 47-48. In evaluating the Company's overall quality of service, he reviewed the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) data filed by the Company in Docket No. E-100, Sub 138A; informal complaints and inquiries from DEC's customers received by the Public Staff's Consumer Services Division; filed Statements of Position in this docket; and his own interactions with DEC and its customers. Id. at 47. He noted that for the period 2008 through 2016, Company reports showed the SAIDI and SAIFI indices are worsening. Id. These trends show that the Company's outages are increasing in frequency, and when outages occur they tend to have a longer duration, on average. Id. He also stated that less than 1% of the direct contacts that the Public Staff's Consumer Service Division received from DEC customers related to service quality issues. Id. at 48. Witness Williamson concluded that the quality of service provided by DEC to its North Carolina retail customers is adequate at this time. Id.

No intervenor offered evidence contradicting the testimony and agreement of the Stipulating Parties that the quality of DEC's service is adequate. Therefore, consistent with the evidence and Section IV.J. of the Stipulation, the Commission finds and concludes that the overall quality of electric service provided by DEC is adequate.

Service Regulations

Witness Pirro described the proposed changes to DEC's Service Regulations. His pre-filed direct testimony on this matter was modified by his updated Exhibit 1 filed on December 19, 2017. Most of the revisions involve relatively small changes in charges, increases in some and decreases in others, imposed by DEC for various services, including the following.

(1) An increase in the reconnection fee from $25.00 to $27.13 during regular business hours, and a decrease from $75.00 to $27.13 during all other hours [Section XII].
(2) An increase in the initial customer connection charge from $15.00 to $24.18. [Section II].
(3) A decrease in the returned check charge from $20.00 to $5.00 [Section XII].
(4) A decrease in the monthly charge for extra facilities over and above those normally provided from 1.1% of the estimated cost to 1.0% per month, but not less than $25 [Section XVI(16)].

In addition, pursuant to DEC's present Service Regulations, if a residential dwelling unit does not meet the definition of "permanent," it will be considered temporary and service will be provided under a general service rate schedule. DEC proposed the following underlined language to Section XVI(1) and (2).

> [A]dditonally, for a manufactured home to be considered permanent, it must also be attached to a permanent foundation, connected to permanent water and sewer facilities, labeled as a structure which can be used as a permanent dwelling, and under a lease arrangement for five (5) years or longer or located on customer-owned land. If the structure does not meet the

> requirements of a permanent dwelling unit, service will be considered temporary and provided on one of the general service rate schedules.
>
> [M]anufactured homes which meet the requirements of a permanent residence under XVI above will be billed in accordance with the applicable residential rate schedule. Nonpermanent manufactured homes will be provided service under XVI(15) Temporary Service below and billed in accordance with the applicable general service rate schedule.

The Commission notes that one of the consequences of Temporary Service is that the customer must pay DEC's actual cost of connection and disconnection, which may be higher than the charges noted above.

Under Section V of its Service Regulations, with regard to rights-of-way, DEC initially proposed the addition of the following underlined language in the first paragraph:

> The Customer shall at all times furnish the Company a satisfactory and lawful right of way easement over his premises for the construction, maintenance and operation of the Company's lines and apparatus necessary or incidental to the furnishing of service. In the absence of formal conveyance, the Company, nevertheless, shall be vested with an easement over Customer's premises authorizing it to do all things necessary to the construction, maintenance and operation of its lines and apparatus for such purpose.

On April 27, 2018, DEC filed a letter stating that it had decided to withdraw from consideration the second sentence proposed under Section V. The Commission accepts DEC's withdrawal of that proposed additional sentence.

No party filed testimony regarding DEC's proposed changes to its Service Regulations. The Commission finds and concludes that DEC's proposed amendments to its Service Regulations are just and reasonable, serve the public interest, and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 34-35

The evidence supporting these findings of fact and conclusions is contained in the Company's Application and Form E-1, the testimony and exhibits of the DEC and Public Staff witnesses, the Stipulation and the Lighting Settlement, and the entire record in this proceeding.

As fully discussed above, the provisions of the Stipulation are the product of the give-and-take of settlement negotiations between DEC and the Public Staff. Comparing the Stipulation to DEC's Application, and considering the direct testimony of the Public Staff's witnesses, the Commission notes that the Stipulation results in a number of downward adjustments to the costs sought to be recovered by DEC. Further, the Commission observes that there are provisions of the Stipulation that are more important to DEC, and, likewise, there are provisions that are more important to the Public Staff. For example, the Public Staff was intent on obtaining a commitment from the Company regarding vegetation management and reduction of the Company's untrimmed, back-log miles. Likewise, DEC was intent on holding the record of this proceeding open to allow the Company to include the final cost amounts of the Lee CC project. Nonetheless, working from different starting points and different perspectives, the Stipulating Parties were able to find common ground and achieve a balanced settlement.

The result is that the Stipulation strikes a fair balance between the interests of DEC and its customers. As discussed above, the Commission has fully evaluated the provisions of the Stipulation and concludes, in the exercise of its independent judgment, that the provisions of the Stipulation are just and reasonable to all parties to this proceeding in light of the evidence presented, and serve the public interest. The provisions of the Stipulation strike the appropriate balance between the interests of DEC's customers in receiving safe, adequate, and reliable electric service at the lowest reasonably possible rates, and the interests of DEC in maintaining the Company's financial strength at a level that enables the Company to attract sufficient capital. Further, the Commission finds and concludes that the revenue requirement, rate design, and the rates that will result from the Stipulation, subject to the Commission's decisions set forth below on the contested issues, will provide just and reasonable rates for DEC and its retail customers.

Therefore, the Commission approves the Stipulation in its entirety. In addition, the Commission finds and concludes that the Stipulation is entitled to substantial weight and consideration in the Commission's decision in this docket. Further, the Commission concludes that the Lighting Settlement entered into by DEC with NCLM, and the Cities of Concord, Kings Mountain, and Durham is in the public interest and should be approved in its entirety.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 36

The evidence supporting this finding and conclusions is contained in the verified Application and Form E-1 of DEC, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

Company witness Pirro explained that the Company proposes to increase (or decrease) the BFC for each rate class to better reflect the underlying cost of serving customers regardless of the customer's level of energy use. Tr. Vol. 19, pp. 60, 63. Pirro Exhibit 8 shows the Company's proposed BFCs, which are based on a percentage difference between the current BFC and the costs determined in the Company's cost of service study provided by witness McManeus. Id. at 63. Specifically, DEC proposes to increase the monthly BFC for the residential rate class, other than Schedule RT, from $11.80 to $17.79, which reflects approximately 50% of the difference between the current rate of $11.80 and the customer-related cost of $23.78 identified in the cost study. Id. at 60; Pirro Ex. 8. Although the Company's analysis supports increasing the residential BFC to $23.78, the Company has proposed a smaller increase to moderate any effect on low-usage customers. Id.

Several intervenors provided testimony regarding the Company's proposed increases to the BFCs. Public Staff witness Floyd testified that DEC's requested increase is unreasonable given the impact of a large increase on low-usage customers. Tr. Vol. 23, p. 63. He notes that the BFC is an unavoidable charge and constitutes a large percentage of the bill for low-usage residential customers. Id. Witness Floyd explained that if DEC is granted its requested rate increase, approximately 45% of the total revenue increase from residential customers will come solely from the increase in the BFC. Id.

Witness Floyd recommends that any increase in the residential BFC should be limited to 25% of the approved revenue increase assigned to that customer class. Tr. Vol. 23, p. 64. Under the Company's proposed revenue increase of approximately $612 million, this produces a BFC of approximately $15.10 for Schedule RS. Id. at 63-64. Alternatively, witness Floyd recommended that the BFC remain unchanged in the event the Commission ordered a decrease in the revenue requirement as a result of this proceeding. Id. at 64.

NCSEA witness Barnes testified that the Company's proposed fixed customer charge increases are "extreme" and recommended that the current customer charges be maintained, or, alternatively, that the customer charges only be increased by the percentage increase in the overall revenue requirements adopted for each class. Tr. Vol. 20, p. 61. Specifically, witness Barnes testified that the increased residential BFC proposed by the Company was higher than other utilities and is therefore inappropriate. Id. at 66-69. Witness Barnes also argues that the proposed increases are inconsistent with the ratemaking principle of gradualism. Id. at 70.

Witness Barnes, as well as NC Justice Center, et al. witness Wallach, also assert that an increase in the customer charge dilutes customer incentives for distributed generation and energy efficiency. See id. at 71-73; Tr. Vol. 8, pp. 70-76. Witness Wallach argues that the customer charge should be consistent with the "true minimum plant cost per customer" (which is $11.08/month for residential customers), and that all other customer-related costs should be included in the volumetric energy rate. Tr. Vol. 8, pp. 68-72. Witness Wallach also takes issue with the Company's use of the minimum system analysis to determine customer-related distribution plant costs, as further discussed in this Order in the analysis related to Finding and Conclusion No. 28. Id. at 66-67. Witness Wallach argues that the fact that the BFC "exceeds the true customer-related embedded cost per residential customer indicates that a portion of demand-related distribution plant costs are inappropriately being recovered through the current BFC." Id. at 68. Therefore, residential customers with low usage are subsidizing larger customers under DEC's proposed rates. Id.

NC Justice Center, et al. witness Deberry also opposed the increased residential BFC, testifying that it will affect already cost-burdened residents who struggle to afford housing costs. Tr. Vol. 26, p. 348. Witness Deberry explained that over half of all cost-burdened households are renters without the ability to make investments in energy efficiency. Id. at 350-52. She further explained that the increased BFC would reduce incentives from bill savings for landlords to include utility programs in their property management, and thus the costs of an increased BFC would be passed on to customers least able to afford it. Id. at 354.

Similarly, NC Justice Center, et al. witness Howat testified that increasing fixed customer charges disproportionately impacts low-volume, low-income customers and discourages energy efficiency. Tr. Vol. 8, p. 22. Witness Howat testified that low-income households, and particularly low-income households of color, are at a heightened risk of loss of home energy service. Id. at 31-34.

In addition to the expert testimony of witnesses Howat and Deberry, other non-expert witnesses speaking at the public hearings testified about the hardship of increases in fixed charges to low-income households and senior citizens.

NC Justice Center, et al. in its post-hearing Brief stated that:

> It is in large part because of this disproportionate harm to those subsisting on low and fixed incomes that the National Association of State Utility Customer Advocates (NASUCA) is opposed to increases in mandatory, fixed charges like the BFC in this case. NASUCA Resolution 2015-1 (NCJC et al. Floyd Cross Exhibit 1, Ex. Vol. 23, p. 104.) The NASUCA resolution states that imposing a "high customer charge . . . unjustly shifts costs and disproportionately harms low-income, elderly, and minority ratepayers, in addition to low-users of gas and electric utility service in general."

Id.

The AGO stated in its brief that:

> Duke's proposal to increase the basic monthly charge for residential customers by 51% from $11.80/month to $17.79/month is extreme and inappropriate, particularly in the circumstances of this case. The proposal should be denied because it will discourage consumers from making investments in energy efficient products and home improvements or from taking other careful measures to budget their consumption, contrary to statutory public policy goals favoring energy efficiency and energy conservation.

AGO's Brief, pp. 91-92.

In his rebuttal testimony, Company witness Pirro responded to the arguments raised by these intervenors regarding the proposed increases to the residential BFC. First, he explained that "[i]t is important that the Company's rates reflect cost causation to minimize subsidization of customers within the rate class." Tr. Vol. 19, p. 83. Witness Pirro explained that "customer-related costs are unaffected by changes in customer consumption and therefore should be paid by each participant, regardless of their consumption." Id. He further explained that any customer-related revenue not recovered in the BFC is shifted to energy rates, which contrary to NC Justice Center, et al.'s position, actually results in high usage customers subsidizing the rates of lower usage customers. Id.

Witness Pirro disagreed with Public Staff witness Floyd's recommendation to limit the BFC to recover no more than 25% of the revenue increase approved for the rate class. Id. at 84. He explained that the Company shares witness Floyd's concern regarding the size of the increase and is sensitive to the impact of the BFC on its customers. Id. The Company has reflected that concern in its request to limit the increase to less than the fully justified customer-related cost. Id. An economically efficient rate design minimizes subsidization between customers and customer classes, and the Company has reflected this principle in its proposal. Id. While witness Floyd's recommendation moves to reduce subsidization, the Company is concerned that deferring a larger increase at this time merely shifts the need to increase the BFC to a future rate case proceeding. Id.

Additionally, witness Pirro responded to NCSEA witness Barnes' argument that DEC's BFC is higher than other utilities and is, therefore, inappropriate. Id. He explained that a utility's rates should be set based upon a careful examination of the individual utility's cost of service and an allocation of those costs to the jurisdictions and customer classes based upon methodologies found appropriate by the Commission. Id. In this proceeding, the Company has examined its costs and identified customer-related costs in excess of its current BFC. Id. Other utilities' cost and rates are irrelevant to a determination of DEC's rates. Id.

In response to witnesses Barnes and Wallach's assertion that an increased BFC discourages energy efficiency, Company witness Pirro countered that failing to properly recover customer-related cost via a fixed monthly charge provides an inappropriate price signal to customers and fails to adequately reflect cost causation. Id. at 85. Shifting customer-related cost to the kWh energy rate further exacerbates this concern and over-compensates energy efficiency and distributed generation for the cost avoided by their actions. Id.

Witness Pirro also responded to NC Justice Center, et al. witnesses Howat and Deberry's testimony regarding the disproportionate impact of an increased BFC on low-income customers. Witness Pirro explained that the Company is mindful of the impact of any rate increase on its customers, particularly low-income customers; however, the Company does not design rates based upon customer incomes, but rather applies cost causation principles to the extent practicable. Id. at 85. Witness Pirro explained that the Company uses other means to address the financial needs of low-income customers which are more effective than biasing the rate design, such as the Company's Residential Income Qualified Energy Efficiency and Weatherization Assistance Program, budget billing and payment arrangements, and Energy Neighbor Fund. Id. at 85-86.

At the hearing, Witness Pirro testified on redirect that the BFC increase the Company has requested is $5.99 per month, which would equate to 19 to 20 cents per day. Tr. Vol. 20, pp. 21-22. He also testified on redirect that, unfortunately, even though some of DEC's customers cannot afford such an increase, it is still appropriate to increase the BFC based upon cost causation rate design principles. Id. at 22-23. Witness Pirro explained that the Company used the concept of gradualism to effectively recover costs as they are incurred, but determined it was appropriate to seek only half of the difference between the current BFC charge and the fully-allocated cost of the BFC in this proceeding. Id. Witness Pirro further explained that any costs not recovered through the BFC are then recovered for the residential class through the energy charge, which creates different subsidies within that class. Id. at 23.

Based upon the entire record in this proceeding, the Commission concludes that DEC shall increase the monthly BFC for the residential rate class (Schedules RS, RT, RE, ES, and ESA) to $14.00. The Commission finds and concludes that the increase in the BFC for the residential rate class schedules is just and reasonable and strikes the appropriate balance providing rates that more clearly reflect actual cost causation. The increase in these schedules minimizes subsidization and provides more appropriate price signals to customers in the rate class, while also moderating the impact of such increase on low-income customers to the extent that they are high-usage customers such as those residing in poorly insulated manufactured homes. In arriving at this decision, the Commission gives substantial weight to the testimony of Company witness Pirro concerning cost of service. The Commission agrees with witness Pirro's testimony that failing to properly recover customer-related cost via a fixed monthly charge provides an inappropriate price signal to customers and fails to adequately reflect cost causation.

Further, the Commission agrees with witness Pirro's testimony that shifting customer-related cost to the kWh energy rate further exacerbates these concerns and may over-compensate energy efficiency and distributed generation for the cost avoided by their actions. However, the Commission does not find sufficient support in this proceeding to increase the BFC to $17.79 as proposed by the Company. Rather, the Commission in this proceeding finds, in response to parties resisting any increase in the BFC, that the modified increase in the residential BFC is appropriate. The Commission finds and concludes that it is just and reasonable that the BFC for other non-residential rate schedules shall be left unchanged at this time based upon the evidence in the record. In support of these conclusions, the Commission notes that other non-residential rate schedules are more complex, thus allowing for the minimization of cost-subsidization issues and ensuring greater consistency with cost causation and allocation principles. In addition, the Commission notes that a greater amount of fixed costs in the residential rate schedule, as opposed to non-residential rate schedules, presently are recovered through variable energy rates, which is inconsistent with basic cost allocation principles that fixed costs should be recovered through fixed charges, whereas variable costs should be recovered through variable charges. The Commission further notes that it likely will review and evaluate several competing theories on this issue in the near future, when a docket is created to review net metering rate schedules pursuant to the directive set forth in House Bill 589. Finally, although the parties dispute the extent to which the residential class should bear responsibility for fixed or demand related costs, the $14.00 charge the Commission approves lies within the range of the charges advocated by the parties. In its discretion, the Commission determines that $14.00 is the appropriate charge for purposes of this case. While DEC's evidence would support a higher charge, the Commission determines that cost causation analyses are inherently subjective and selecting a charge within the range advocated based on differing cost causation models is appropriate.

The Commission is sensitive to the impact of increasing fixed costs to any customer and especially low-income households. Nevertheless, all customer classes and the residential class in particular are composed of individual consumers with divergent usage patterns and financial situations. Class rates by definition are based on averages. Any changes in rate structure affects individual consumers differently depending on their usage. The Commission acknowledges the testimony of witness Pirro where he explained that the Company uses other means to address the financial needs of low-income customers which are more effective than biasing the rate design. In its cover letter, dated June 1, 2018, concerning the Pilot Grid Rider Agreement, the Company committed to making a shareholder-funded contribution totaling $4 million to certain programs to help mitigate the impact of rate adjustments on low-income customers and to support job training. The Commission fully endorses the Company's desire to contribute shareholder funds to support low-income programs and concludes that the $4 million should be used exclusively for the benefit of low-income customers through programs such as Share the Warmth. The Commission encourages the Company, to the extent it is able, to identify low-income customers likely to discontinue service prior to bringing their accounts up to date, in order to provide assistance and thereby reducing uncollectible accounts.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 37

The evidence supporting this finding of fact and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

The Stipulating Parties have not agreed regarding the methodology for calculating customer usage through December 2017. While Public Staff witness Saillor generally adopted the Company's approach, he made certain modifications to the Company's calculations. Tr. Vol. 19, pp. 98-99. The Company agrees with some of the modifications proposed by witness Saillor,[1] however, there are a few changes to witness Saillor's proposal that the Company proposes in order to "place the growth adjustment on a sound footing and to provide a consistent methodology." Id. at 99. In his rebuttal testimony, witness Pirro explained that the Company proposes (a) to remove the usage adjustment made for the test period, (b) to eliminate the use of a de-trending scheme used in the usage adjustment for the extended period, and (c) to include the lost sales of closed accounts in the extended period. Id.

First, witness Saillor made a usage adjustment of 29,329,823 kWh, which was calculated as an adjustment of the test period Y2016 to the previous year Y2015. Id.; Tr. Vol. 26, p. 904. Witness Pirro explained that while there is a basis for adjusting the usage in the test period (Y2016) for the usage in the extended period (Y2017) because the Company included the extended period in its calculations, there is no basis for including the previous year (Y2015). Tr. Vol. 19, pp. 99-100. He explained that Y2015 is not within scope of this proceeding and requires no linkages with test period data for the purpose of a usage adjustment. Id. at 100.

Secondly, witness Pirro explained that the Company does not agree with witness Saillor's usage adjustment of 314,916,793 kWh for residential accounts that employs a de-trending scheme. Id. Witness Pirro asserted that this adjustment is arbitrary and unnecessary. Id. He explained that the regression models used to predict customers at end of period have in effect already de-trended the per capita usage. Id. Also, witness Saillor's method uses an averaging scheme that uses data points twelve months apart and therefore the sales for which the adjustments are being calculated are not the total sales for the period. Id. Witness Pirro explained that the Company has recomputed the usage adjustment using the same weather adjusted series that Saillor has used but without the de-trending. Id.

Additionally, witness Saillor extended the customer growth adjustment from the end of the test period to November 30, 2017, to correspond with the Company's decision to update for plant additions and related expenses through that date. Tr. Vol. 26, p. 904. Witness Pirro explained that for the lost sales from initial accounts, witness Saillor adds 12 months of estimated sales to the new customers during the extended period (through November 2017) to the initial estimate. Tr. Vol. 19, p. 100. However, the closed accounts have only their test period sales removed which differs from the treatment of initial accounts. Id. For parity, witness Pirro asserted that the entire usage of the closed accounts from January 2016 through November 2017 should be used, and the

[1] For instance, witness Saillor proposed the use of weather-adjusted data instead of the actual billed usage which the Company does not oppose. Tr. Vol. 19, p. 99.

Company has added the usage of closed accounts in the extended period to the customer-by-customer adjustment. Id.

Finally, witness Pirro testified that the 12 months ended December 2017, which includes an additional month to the original analysis which was terminated at November 2017, should be used. Id. at 101. He explained that such an analysis was provided to the Public Staff but it did not include the modifications proposed by witness Saillor. Id. The Company therefore submitted an updated analysis for the 12 months ended December 2017 accepting the use of weather-adjusted usage data but rejecting the items described above and recommended that it be adopted in this proceeding and used to determine the growth adjustment. Id. In his supplemental testimony, witness Saillor incorporated customer data for the month of December 2017 in his customer growth analysis. Tr. Vol. 26, p. 911.

In light of the evidence presented, the Commission finds and concludes that Public Staff witness Saillor's methodology for calculating customer usage as set forth in his testimony, with the adjustments proposed by Company witness Pirro in his rebuttal testimony, is just and reasonable to all of the parties and should be employed by the Company in this case.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 38-40

The evidence supporting these findings of fact and conclusions is contained in the Company's verified Application, Form E-1, the record in Docket No. E-100, Sub 147 from October 3, 2016, and the testimony and exhibits of the following expert witnesses: DEC witnesses Schneider, McManeus and Pirro; Public Staff witnesses Floyd, McCullar and Maness; EDF witness Alvarez; and NCSEA witness Murray.

Proceedings in Docket No. E-100, Sub 147

By Orders dated April 11, 2012, and May 6, 2013, in Docket No. E-100, Sub 126, the Commission adopted rules requiring electric utilities, that file integrated resource plans (IRPs), to include in their IRPs information on how planned "smart grid" deployment would impact the utilities' resource needs. In addition, the Commission established a new requirement, Rule R8-60.1, for the electric utilities to file smart grid technology plans (SGTPs) every two years, with updates in the intervening years. The initial SGTPs were filed by the electric utilities on October 1, 2014.

On October 3, 2016, DEC and Duke Energy Progress, LLC (DEP) filed their SGTPs in Docket No. E-100, Sub 147 (SGTP Docket). Dominion Energy North Carolina (DENC) had previously filed its SGTP. Subsequently, comments were filed by the Public Staff, NCSEA and EDF. In addition, reply comments were filed by DENC, and jointly by DEP and DEC.

In summary, DEC's 2016 SGTP identified 14 smart grid technology projects that it was in the process of implementing, or was planning to implement in the next five years. Two such projects are AMI Phase 2 and AMI Expansion 2015. With regard to AMI Phase 2, DEC explained that it initiated a limited-scale project in 2013 leveraging grant funds from the U.S. Department of Energy (DOE) to deploy AMI in North Carolina and South Carolina. Phase 2 of the project replaced aging Advanced Meter Reading (AMR) meters with AMI. Phase 2 was completed in the first quarter of 2015. Including the meters previously installed in Phase 1, the project has installed about 313,500 AMI meters in North Carolina.

With respect to AMI Expansion 2015, DEC stated that it pursued a limited-scope AMI project to install approximately 181,000 AMI meters to serve residential customers in the Charlotte Metro area, and that the project was completed in July 2016.

DEC further stated that as of September 2016, it had cumulatively installed 527,391 AMI meters, an increase of approximately 252,260 AMI meters since its 2014 SGTP. DEC also identified four smart grid technologies actively under consideration: (1) AMI deployment; (2) usage alerts; (3) outage notifications; and (4) Pick Your Own Due Date. With respect to AMI deployment, DEC stated that in 2016 it began evaluating the case for continuing with incremental AMI deployments at about 150,000 per year, or moving forward with a project to replace all remaining AMR meters with AMI.

On March 29, 2017, the Commission issued an Order Accepting Smart Grid Technology Plans (SGTP Order) in Docket No. E-100, Sub 147. The SGTP Order reviewed and accepted the 2016 SGTPs filed by DEC, DEP and DENC.

On May 5, 2017, DEC and DEP filed supplemental information regarding DEC's and DEP's 2016 SGTPs. In summary, DEC advised the Commission that in late 2016 it decided to begin a full scale deployment of AMI in North Carolina, that it began implementing that decision in early 2017, and that it expected to complete its AMI deployment in North Carolina in 2019. DEC attached a cost-benefit analysis and other information regarding its decision to deploy AMI. The cost-benefit analysis concluded that DEC's AMI deployment would result in net benefits having a present value of $117.1 million. Supplemental Filing, Exhibit No. 2. The largest category of benefits included in the analysis is entitled, "Non-technical line loss reduction - power theft, equipment failures and installation errors" (NLLR). It is the last column of benefits shown on Exhibit No. 2, and totals $634.8 million.

On August 21, 2017, the Commission issued an Order Requiring Smart Meter Plan Presentation by Duke Energy Carolinas, LLC (SGTP Presentation Order). The Order scheduled a presentation on AMI by DEC, and included several questions to be answered by DEC regarding its decision to deploy AMI. Subsequently, in response to question number 2 included in the Commission's SGTP Presentation Order, DEC stated that the $634.8 million of NLLR included in its cost-benefit analysis was based on a 2008 report by the Electric Power Research Institute (EPRI). The EPRI report noted that industry experts project that a reasonable percentage for non-technical losses is 2% of gross revenue. DEC stated that it used this 2% of revenue approach to calculate the NLLR in its AMI cost-benefit analysis. Further, during the SGTP presentation by DEC on October 10, 2017, witness Schneider stated that based on DEC's cost-benefit analysis the costs of the AMI deployment would outweigh the benefits until 2025.

On October 2, 2017, DEC and DEP filed their SGTP update reports (SGTP Updates) in Docket No. E-100, Sub 147. In DEC's SGTP Update, on pages 6-8, DEC provided the information regarding its AMI deployment. In summary, DEC stated that through August 2017 it had installed approximately 850,000 AMI meters in North Carolina, and planned to install an additional 1.1 million AMI meters through 2019. Further, DEC stated that it would remove and replace approximately 1.32 million AMR meters from 2017 through 2019. DEC further stated that its AMR meters had an estimated salvage value of $1.37 million, and an estimated remaining net book value of $127.66 million, as of March 31, 2017. In Exhibit A, Appendix C, DEC provided its AMI cost-benefit analysis, which was the same analysis that DEC filed as a part of its supplemental information filing on May 5, 2017.

On November 20, 2017, the Commission issued an Order Requiring Additional Information (Additional Information Order) requesting that DEC respond to several questions about its AMI deployment. In addition, the Commission requested that DEC provide a revised cost-benefit analysis that included (1) DEC's historical kilowatt-hour and lost revenue data for NLLR that DEC has experienced in North Carolina, rather than using the EPRI 2% of revenue calculation, and (2) the cost of replacing AMI meters at the end of their 15-year useful life.

On December 15, 2017, DEC filed its responses, including its revised cost-benefit analysis as Exhibit No. 2. The largest category of benefits included in the analysis continued to be "Non-technical line loss reduction - power theft, equipment failures and installation errors." However, the amount of the NLLR benefit went down from $634.8 million to $448.8 million. In addition, the revised cost-benefit analysis, which included the cost of replacing AMI meters at the end of their 15-year useful life, showed that AMI deployment would result in net costs having a present value of $49.9 million.

Summary of AMI Testimony

DEC witness Schneider described the Company's plan to replace its current meters with AMI meters – often referred to as "smart meters" – that have advanced features, including the capability for two-way communications, interval usage measurement, tamper detection, voltage and reactive power measurement, and net metering capability. Tr. Vol. 18, p. 322. He testified that DEC began the deployment of AMI meters in 2016, and estimates completing implementation in mid-2019. Id. at 323. In 2016, the Company spent $73.9 million on new AMI meters across the system in North and South Carolina. Id. at 326. Witness Schneider explained that the Company's AMI project is not a "simple meter change-out" and will include advanced meters, a two-way communication network, and central computer systems, and that AMI is a foundational investment for DEC that will enable additional customer choice, convenience and control. Id. at 322-33.

Public Staff witness Floyd criticized the Company's cost-benefit analysis, arguing that the Company's expected benefit based on AMI's ability to reduce theft and other revenue losses related to meter tampering was based on an outdated EPRI study and was likely overstated. Tr. Vol. 23, p. 87. In addition, witness Floyd questioned whether the Company will immediately maximize the benefits available to customers from AMI. Id. at 89. He stated, for example, that customers who receive more detailed usage data from AMI should be able to use this data to save on power bills. Id. According to witness Floyd, customers will not be able to do so unless the Company provides new and innovative rate designs, such as TOU rate structures and new payment options, including prepay. Id. at 89-90. Witness Floyd also testified regarding customers who opt-out of having an AMI meter installed. Id. at 90-91. DEC has filed for approval of a Rider MRM in Docket No. E-7, Sub 1115, which would allow customers who desire to opt-out to pay a monthly fee to have a fully manual meter. Id. at 90. Witness Floyd acknowledged that if a significant number of customers opt-out of having an AMI meter, the benefits of AMI deployment will be diminished. Id. The Public Staff, therefore, supports the Company's request for Rider MRM, and encourages the Commission to approve that rider as part of this rate case. Id. at 91.

Public Staff witness Maness criticized the Company's proposed recovery of the remaining book value of replaced AMR meters over three years, the expected deployment period for the AMI program. Tr. Vol. 22, p. 103. Witness Maness testified that the meters being replaced have an average remaining useful life of 15.4 years, and that period should be used in the Company's depreciation study instead of the accelerated three-year period. Id. at 104. Public Staff witness McCullar testified that the Public Staff used the 15.4 year remaining useful life in developing the Public Staff's recommended depreciation rates. Tr. Vol. 26, p. 788. Witness McCullar also testified that DEC should use a 17-year average service life for AMI meters as opposed to the 15 years that the Company has proposed. Id. at 787.

Other than these concerns, however, the Public Staff stated that "the Company has made a reasonable assessment of the costs and benefits associated with its proposed deployment of AMI." Tr. Vol. 23, p. 92. The Public Staff does not object to the inclusion of the Company's AMI costs incurred to date and included in this case. Id. at 93.

EDF witness Alvarez also testified concerning the Company's cost-benefit analysis for AMI. Tr. Vol. 26, pp. 311-13. Witness Alvarez recommended that stakeholders be allowed the opportunity to conduct a detailed examination of the Company's cost-benefit analysis for its AMI program as part of a distinct grid modernization docket. Id. at 312.

NCSEA witness Murray also recommended that the Company implement a "bring your own device" offering that allows customers to connect Home Area Networks (HAN) directly to the Company's AMI radio to access energy usage information. Tr. Vol. 26, p. 401.

Company witness Schneider testified in response to these arguments. First, he responded to the Public Staff's criticism of the Company's cost-benefit analysis. Tr. Vol. 18, pp. 331-32. He explained that the Company based its reduction in revenue erosion from meter tampering on a 2008 EPRI study because analyzing non-technical loss is significantly complex and it would not be possible to use the actual historical kilowatt-hour and lost revenue data for energy theft that DEC has experienced. Id. at 332. In response to criticism that the Company will not maximize benefit to customers, witness Schneider explained that DEC has already implemented two new programs for DEC customers with smart meters, Pick Your Due Date and Usage Alerts. Id. at 334-35. He also explained that the Company plans to offer more innovative rate designs to complement AMI in the future, as detailed by Company witness Pirro. Witness Schneider also explained that all customers receiving smart meters under the AMI project will receive benefit from remote meter reading and mass meter interrogation capabilities, which allow the Company to quickly assess outages and restore power more efficiently. Id. at 335-37.

Witness Schneider testified that DEC agrees that customers should have the choice to opt-out of the AMI meter through a cost-based tariff. Id. at 337. The Company agrees with the Public Staff that the Commission should approve the opt-out program as filed, and respectfully requests approval by the Commission soon. Id. At the hearing in response to questioning by Commissioner Gray, witness Schneider explained that when a customer expresses concern with the new AMI meters, the Company attempts to address those concerns, and if the customer is adamant about not wanting a new meter, the customer is added to a bypass list. Tr. Vol. 18, p. 415. Currently, there are approximately 4,000 people on the bypass list, which equates to 0.3% of DEC's North Carolina customers. Id. at 415-16.

Witness Schneider also addressed witness McCullar's recommendation that a 17-year average service life for AMI meters be used as opposed to the 15 years that the Company has proposed. Tr. Vol. 18, p. 338. Witness Schneider testified that "[g]iven the pace of technology advancement, the trend across the industry is shorter depreciation schedules from a regulatory and accounting perspective, as systems such as AMI are more computer and sensor driven." Id. at 338-39. He also noted that the Commissions in Indiana, Kentucky, Ohio and Florida all utilize 15-year depreciation lives for the Duke Energy AMI meters deployed in those jurisdictions. Id. at 339.

Additionally, witness Schneider responded to witnesses Alvarez's criticism of the Company's cost-benefit analysis. He explained that "the Company's AMI cost-benefit analysis was filed in DEC's SGTP on October 2, 2017 in Docket No. E-100, Sub 147.[1] Id. at 339. "In past SGTP dockets, the Company has discussed that parties likely have different definitions of a "cost-benefit" analysis, and there is not a standard template that every project related to smart grid technologies follows in completing the evaluation and analysis for determining the business case for a specific technology." Id. Instead, many different factors go into the Company's decision to invest in a specific technology at a specific time. Id. Witness Schneider explained that "DE Carolinas believes that the Commission's existing SGTP, ratemaking, and EE/DSM processes provide opportunity for stakeholder engagement and comment in the development and approval of such programs to maximize customer benefits." Id. at 340. Moreover, witness Schneider rejected witness Alvarez's recommendation to open a new AMI docket as duplicative, stating that "[t]he Commission already has a SGTP rule and dockets to review, allow for intervenor investigation and comment, and ultimately accept, modify or reject the Company's SGTP and those of the other utilities" and that cost recovery for the AMI project will be subject to the existing robust and transparent rate case process." Id. at 342.

Finally, witness Schneider testified in opposition to witness Murray's recommendation regarding the "bring your own device" offering. Id. at 343-44. He explained that smart meter to HAN connections combine two separate security risks. Id. at 343. First, the current lack of security within internet devices, gateways and applications, and second, external connections to critical infrastructure. Id. For both topics, Duke Energy is deliberately and carefully evaluating the associated risk to the reliability of the power grid. Id. The Company is considering: (1) research conducted by third parties; (2) compliance with National Institute of Standards and Technology (NIST) based security standards that federal and state commissions have encouraged the Company to adopt; and (3) alignment with recently released security principles related to both topics provided by the Department of Homeland Security (DHS), National Security Agency (NSA) and the Department of Energy (DOE). Id. Cyber security threats are of the utmost concern to the Company and therefore, DEC does not support the "bring your own device" recommendation by witness Murray at this time. Id. Furthermore, on cross-examination by counsel for EDF at the

[1] The Commission has taken judicial notice of all filings in Docket No. E-100, Sub 147. Tr. Vol. 18, p. 402.

hearing, witness Schneider supported the Company's position on HAN connections, stating that the Company's cyber security experts have "grave concern" about allowing external connections to the Company's critical grid structure. Id. at 357.

Witness Schneider explained that a secondary concern regarding the "bring your own device" offering is support and upgradeability. Id. at 343. At this time, if a customer buys a device not known to the Company, DEC would not be able to provide support to the customer if that device fails or is not able to connect to the meter. Id. at 343-44. If a new security release is made available the Company may push that to the meter. Id. at 344. The Company would be unable to ensure that a new version that was pushed to the meter is compatible with all of the devices that a customer may have purchased. Id. Customer satisfaction would be impacted along with a large increase in call volumes. Id. Therefore, witness Schneider testified that the Company does not support the "bring your own device" recommendation by witness Murray, unless or until such concerns are addressed. Id.

Summary of Post-Hearing Briefs

In its post-hearing Brief, EDF recommends that the Commission reject DEC's request for cost recovery for AMI meters, and require DEC to establish a regulatory asset for these costs until DEC can demonstrate cost-effectiveness of its AMI deployment. EDF states that customer data access is foundational to realizing the benefits of AMI meters and requests that the Commission require DEC to implement the data access recommendations of NCSEA witness Murray. EDF summarizes witness Murray's recommendations regarding access to usage data, and states that AMI meters will not be used and useful unless DEC implements witness Murray's recommendations.

EDF also cites Public Staff witness Floyd's testimony that the Public Staff's support of DEC's AMI cost recovery is conditioned on DEC providing "informational tools and applications that provide more granular and timely data to allow customers greater insight and control over their actual usage." Tr. Vol. 23, p. 90. EDF contends that witness Murray's recommendations would fulfill this requirement. EDF further states that customer savings from full access to their usage data are quantifiable, and cites DEC witness Schneider's testimony that DEC quantified these benefits for Duke Energy's AMI deployments in Indiana and Kentucky.

In addition, EDF discusses DEC's pilot program to install a device that will receive energy usage data from the Zigbee radio in the customer's AMI meter and transmit the data, via the customer's home wi-fi system, to the customer's cell phone and computer. EDF criticized the fact that DEC will not provide similar data access to third parties or allow customers to purchase their own home energy monitors and synch them up with the AMI meter, stating that this pilot program violates the principle, established in DEC's service regulations, that DEC's electric service ends at the point of delivery, and discriminates by restricting customers to the use of a utility device in order to access their own data. EDF maintains that the Commission should require DEC to implement robust data access now, before DEC receives cost recovery for AMI meters. EDF, therefore, recommends that the Commission reject DEC's request for cost recovery and require it to establish a regulatory asset for AMI costs until DEC implements witness Murray's recommendations.

NCLM, in its post-hearing Brief, cites witness Coughlan's comparison of the time-of-use options offered by DEC and DEP as demonstrating the greater time-of-use offerings that DEP has without fully implementing AMI technologies and Power/Forward. In addition, NCLM cites Public Staff witness Floyd's concern that DEC will not immediately maximize the benefits available to customers of AMI, and his testimony that:

> [i]t will be incumbent upon DEC to maximize the benefits not only by eliminating or reducing expenses to provide utility service or NTLs, but also by providing new opportunities for customers to use both AMI meters and CCP so that they see a real benefit on their bills. Customers who are more aware of their energy use should be empowered to make more informed choices on how they use and pay for energy.

Tr. Vol. 23, p. 89.

NCLM states that complete deployment of AMI is not necessary for DEC to have discussions and receive input from customers on how to develop new rate designs, or to provide additional information to its current OPT-V customers. Moreover, NCLM contends that DEC should be required to increase its reporting on AMI and Customer Connect in order to provide more accountability. NCLM submits that the Commission should order DEC to provide its current time-of-use customers with additional information to maximize the benefits of load shifting, to develop proposals for new and innovative time-of-use and critical peak pricing rate designs and prepayment options before the next rate case, and to provide regular updates to the Commission about its progress in developing and deploying new rate designs.

In its post-hearing Comments, the City of Durham contends that ratepayers currently gain no benefits from AMI meters beyond the benefits received from DEC's used and useful AMR meters. Durham joins with NCLM in its request that the Commission order DEC to develop proposals for new and innovative time-of-use and critical peak pricing rate designs as soon as possible. Finally, Durham expresses concerns about the privacy implications of AMI two-way communications, and requests that the Commission consider ordering a study to be conducted on this issue.

Discussion and Conclusions

In the present docket, as part of DEC's general rate case application, DEC seeks to recover $90.9 million for AMI deployment in North Carolina from January through November 2017. "The requested increase in revenues related to AMI in this case includes a total of $11.2 million for return and depreciation related to this investment." Tr. Vol. 6, pp. 254-55. In addition, DEC requests authority to establish a regulatory asset account. The depreciation study recovers the remaining book value of these assets over 3 years; however, as the individual meters are replaced, DEC needs to move the retired meter balance into a regulatory asset account until the asset is fully depreciated. Id.

A. Reasonableness of AMI Costs

DEC witness McManeus testified regarding the costs of DEC's AMI deployment. Tr. Vol. 6, pp. 254-55. Further, in the SGTP Docket and the present docket, DEC has provided extensive information about its purchases of AMI meters and its costs of installing them. For example, the cost-benefit analyses include columns showing the capital and O&M costs of the AMI project. In addition, on March 26, 2018, at the request of the Commission, the Public Staff filed a late-filed exhibit that included a spread sheet provided by DEC in response to a Public Staff data request. In part, the exhibit shows that the total capital cost of DEC's AMI programs through September 2014 was $94.43 million, with $26.85 million having been provided by the DOE grant.

The Commission gives substantial weight to the above testimony and documentary evidence. In addition, no party has questioned the reasonableness of DEC's AMI costs. In State ex rel. Utils. Comm'n v. Intervenor Residents, 305 N.C. 62, 75-77, 286 S.E.2d 770, 778-79 (1982), the North Carolina Supreme Court held that the uncontested evidence of a public utility regarding the reasonableness of its costs can be accepted by the Commission as satisfying the utility's burden of proof on the question of cost recovery. As a result, the Commission finds and concludes that DEC has met its burden of showing that its AMI costs were reasonable. Public Staff witness Floyd testified:

> Except for the concerns I have raised concerning DEC's cost-benefit analysis, I believe the Company has made a reasonable assessment of the costs and benefits associated with its proposed deployment of AMI ... I do not object to inclusion of the Company's AMI costs incurred to date and included in this filing.

Tr. Vol. 23, pp. 92-93. Therefore, the Commission authorizes recovery on the merits on the basis of these uncontested recommendations.

As described above in the details of the SGTP Docket, DEC has followed a studied and deliberate plan for installing AMI, including the AMI Phase 1 and Phase 2 projects, and the AMI Expansion 2015 project. With regard to AMI Phase 1 and 2, DEC explained that it initiated the project in 2013. Leveraging grant funds from DOE, DEC replaced aging AMR with AMI in North Carolina and South Carolina. Phase 2 was completed in the first quarter of 2015, bringing the total of installed AMI meters to about 313,500 in North Carolina. In DEC's AMI Expansion 2015, DEC pursued a limited-scope AMI project to install approximately 181,000 AMI meters to serve residential customers in the Charlotte Metro area. That project was completed in July 2016. As of September 2016, DEC had cumulatively installed about 527,391 AMI meters. After gaining substantial knowledge about AMI provided by the installation of more than 500,000 AMI meters, DEC made a decision in late 2016 to begin full scale deployment of AMI in North Carolina, and began implementing that decision in early 2017.

The Commission gives substantial weight to the above evidence. AMI is a new technology. Maintaining adequate and reliable electric service includes staying abreast of the latest developments in equipment and technology. Indeed, advances in technology can provide efficiencies and other benefits that justify retiring present equipment. After having deployed AMI on a project-by-project basis for several years, it was reasonable and prudent for DEC to use that experience to decide to deploy AMI on a full scale.

In DEC's Supplemental Filing in the SGTP Docket, DEC discussed the possibility of additional customer services to be provided by AMI.

> [A]MI is the foundational investment that will enable enhanced customer solutions – giving customers greater control, convenience and choice over their energy usage, while also giving customers the opportunity to budget, save time and money. AMI technology allows a utility to gather more granular usage data and utilize new capabilities to offer new programs and services to customers that are not achievable through existing meters. The AMI technology will pave the way for programs that will allow customers to stay better informed during outages, control their due dates, avoid deposits, to be reconnected faster, and to better understand and take control of their energy usage, and ultimately, their bills. Over time, the Company also expects AMI meters to contribute to cost reductions from reduced truck rolls in the years after deployments.

Supplemental Filing, p. 1.

In addition, during redirect examination by DEC's counsel witness Schneider stated:

> [t]here is a lot of additional customer programs and benefits that the AMI, as a foundation, enables that, again, we didn't have those costs and benefits in our cost-benefit model because they just weren't designed yet. We didn't know what the costs were in each of those cases, you know, will be on their own. So in general, with a positive business case, and plus the fact that we know there is additional customer products and services that this solution can enable, the Company has made a decision that this is a viable project that we want to move forward with.

Tr. Vol. 18, pp. 413-14.

The Commission gives substantial weight to the above evidence. The AMI benefits, current and future, identified by DEC are substantial. It was reasonable and prudent for DEC to rely on these AMI benefits in deciding to deploy AMI on a full scale.

However, the Commission also agrees with NCLM, EDF and others that DEC should be required to follow through on designing and proposing new rate structures that will capture the full benefits of AMI. Therefore, the Commission finds and concludes that DEC should within six months of the date of this Order file in this docket the details of proposed new time-of-use, peak pricing, and other dynamic rate structures that will, among other things, allow ratepayers in all customer classes to use the information provided by AMI to reduce their peak time usage and to save energy. The Commission's goal is to require DEC to develop rate structures now that will enable DEC to deliver on its promise that there are "additional customer products and services that this solution [AMI] can enable" no later than DEC's next general rate case. Further, the Commission hereby gives DEC notice that DEC's success, or lack thereof, in developing new rate structures that enable AMI energy usage benefits will be one of the factors used by the Commission in determining the prudence and reasonableness of DEC's costs incurred in deploying AMI following the present rate case. In addition, as discussed subsequently herein, the Commission has directed DEC to continue working with the Public Staff, EDF and other interested parties to develop guidelines for access to customer usage data.

As noted above, the two cost-benefit analyses produced mixed results regarding the net present value of the costs and benefits of AMI. As a result, the Commission finds that the results of these analyses are not helpful in determining the benefits to be derived from AMI. Therefore, the Commission gives little weight to the conclusions of the cost-benefit analyses as to the net present value of AMI benefits and costs.

No party provided substantial evidence of a lack of prudence by DEC in its decision to deploy AMI. Although the Public Staff and EDF levied some general criticisms of DEC's cost-benefit analyses, they offered no concrete or probative evidence as to why the costs should not be recovered or a lack of reasonable decision making by DEC. Indeed, the Public Staff concluded that DEC made a reasonable assessment of AMI and, therefore, the Public Staff did not object to DEC's recovery of its AMI costs.

Based on the substantial evidence of DEC's project-by-project deployment of AMI for several years, and the current and future AMI benefits identified by DEC, the Commission concludes that a preponderance of the evidence shows that DEC's decision in early 2017 to fully deploy AMI was a prudent decision.

B. Appropriate Remaining Useful Life for AMR Meters

DEC's 2017 SGTP Update showed that the remaining net book value of its AMR meters was an estimated $127.66 million as of March 31, 2017. However, in the SGTP presentation witness Schneider testified that DEC would receive tax benefits that would reduce the lost book value to approximately $85 million. SGTP Presentation. DEC proposes in its depreciation study to recover the remaining net book value of the AMR meters over three years. Public Staff witness Maness does not oppose the establishment of a regulatory asset account to track the retirement and remaining depreciation of the replaced meters, but he opposes customers being charged the entire cost over 3 years. Public Staff witness Maness testified that DEC's existing AMR meters have an average remaining useful life of 15.4 years, and that 15.4 years should be used as the remaining useful life when developing depreciation rates.

DEC's deployment of AMR meters was a reasonable and prudent decision that helped DEC and its ratepayers capture the benefits of new metering technology at that time. Likewise, the Commission has determined that DEC's deployment of AMI today is a reasonable and prudent decision. Further, the Commission gives significant weight to the Public Staff's position that DEC should be allowed to recover the remaining book value of is AMR meters, but that the remaining useful life should be for 15 years, rather than the three years as requested by DEC.

With regard to EDF's recommendation to place AMI in a new docket, the Commission concludes that the current SGTP docket is the appropriate docket in which to obtain information and review the electric utilities' AMI plans. Moreover, the Commission finds and concludes that the potential benefits and risks of the "bring your own device" program advocated by NCSEA witness Murray can be studied and discussed in the meetings ordered in Docket No. E-100, Sub 147 regarding access to customer usage data.

In summary, the Commission finds good cause to grant DEC's request to recover its AMI costs. Further, the Commission finds good cause to require DEC to within six months of the date of this

Order file proposed new time-of-use, peak pricing, and other dynamic rate structures that will, among other things, allow ratepayers in all customer classes to use the information provided by AMI to reduce their peak time usage and to save energy. Finally, the Commission finds and concludes that DEC may establish a regulatory asset to track the retirement and remaining depreciation of AMR meters, but DEC shall use a 15-year remaining useful life in its depreciation study.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 41

The evidence supporting this finding of fact and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, Docket No. E-100, Sub 147, the testimony of DEC witness Hunsicker, EDF witness Alvarez, and NCSEA witness Murray, and the entire record in this proceeding.

NCSEA witness Murray testified that DEC should provide customer usage data information, recorded by AMI, to customers and authorized third parties; provide historic use and current rate data to customers and authorized third parties in machine readable (xml) format; and establish a customer authorization process. Tr. Vol. 26, pp. 400-02. Both witness Murray and EDF witness Alvarez recommended that the Commission consider providing the energy usage data to customers and third parties through Green Button Connect My Data (GBC), a nationally standardized and automated method. Id. at 326-27, 412. According to witness Murray, a principal advantage of GBC is that consumers can automatically transmit data to third parties without having to purchase additional metering equipment for their home or building. Id. at 412.

In her rebuttal testimony, Company witness Hunsicker testified that DEC agrees with and defers to Public Staff witness Floyd's recommendation in his testimony to protect customer data and adhere to the Code of Conduct as it relates to the sharing of customer information. Tr. Vol. 18, p. 278. Witness Hunsicker further testified that providing third parties with access to consumption and load profile, which witness Murray recommends, would violate the prohibition against disclosing customer information to third parties. Id. According to witness Hunsicker, customers already have access to historic usage data in the form of bills and via the Company's external website, and that the Company plans to assess the possibility of providing usage information to customers using certain "Green Button" programs. Id. At the hearing, witness Hunsicker opined that customers have a basic right to access their usage data, but explained that the Company compiles the data and analyzes it using Company software, which creates a co-ownership of the data. Id. at 310. Witness Hunsicker further testified that the Company takes no issue with providing the capability for third party access to customer data, provided the following requirements are met: (1) the costs for the platform are borne by the participating customers; (2) the implementation of the platform has no impact on the Company's system or data security; (3) the appropriate customer and regulatory consents are complied with, including the Code of Conduct; and (4) the ongoing monitoring of the additional platform does not become disruptive of the Company's daily operation. Id. at 299-300. However, witness Hunsicker expressed particular concerns with providing data directly to third parties via an automated process due to the possibility of physical security risks resulting from increased third-party access to customer usage data and the potential for third parties to create customer confusion and possibly misrepresent their affiliation with the Company. Id. Witness Hunsicker stated that the Company looks forward to discussing these issues in more detail in the meeting to discuss guidelines for access to customer usage data, as directed by the Commission in its March 7, 2018 Smart Grid Technology Plan Update Order in Docket No. E-100, Sub 147. Id.

The Commission appreciates the recommendation of NCSEA and EDF regarding the collection and dissemination of customer usage data. However, the Commission is not persuaded that this is the time or the proceeding in which to impose such requirements on the Company. As witness Hunsicker testified, the Commission and interested parties are addressing issues regarding access to customer usage data in Docket No. E-100, Sub 147. In that docket, on March 7, 2018, the Commission issued an order on DEC's and DEP's (collectively, Duke's) 2017 Smart Grid Technology Plan (SGTP) Updates that included the following directive on access to customer data:

> [T]herefore, the Commission finds good cause to direct that Duke convene and facilitate discussions with NCSEA, the Public Staff, and other interested parties on this topic, with the goal of reaching agreement on all aspects, or as many aspects as possible, of the rule proposed by NCSEA. In addition, the Commission requests that the discussions include the Green Button Connect My Data system for data access. The Commission further directs that Duke provide the Commission a report detailing the discussions, agreements reached on particular points, points on which agreement has not been reached, and the barriers to agreement on remaining points, as well as the parties' plans for further discussions. The report shall be filed in Docket No. E-100, Sub 147 no later than 30 days after the first meeting of the stakeholder group. Further, the Commission directs Duke to reflect the results of these discussions in its 2018 SGTP reports.

2017 SGTP Order, at 10.

As a result, the Commission declines to adopt NCSEA's and EDF's proposal at this time.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 42-44

The evidence supporting these findings of fact and conclusions of law is found in the Application, the Stipulation, and the entire record in this proceeding, particularly the testimony and exhibits of the following expert witnesses: DEC witnesses Fountain, McManeus, and Simpson, Public Staff witnesses McLawhorn, Williamson, Parcell, and Maness; Commercial Group witnesses Chriss and Rosa, CIGFUR III witness Phillips, Kroger witness Higgins, EDF witness Alvarez, NCSEA witnesses Barnes and Golin, Tech Customers witness Strunk; and CUCA witness O'Donnell.

The expert witness testimony and exhibits regarding Duke's Power Forward Carolinas initiative (Power Forward) and DEC's request for special ratemaking treatment of Power Forward costs is voluminous. The Commission has carefully considered all of the evidence and the record as a whole. However, the Commission has not attempted to recount every statement of every witness. Rather, this Order provides a thorough summary of the evidence.

Likewise, the Commission has read and fully considered the parties' post-hearing briefs. However, the Commission has not in this Order expressly addressed every contention advanced or authority cited in the briefs, almost all of which address Power Forward or the Grid Rider in some fashion. Based upon the evidence and reasons addressed below, the Commission determines that DEC's request to establish a Grid Rider or, in the alternative, to allow deferral accounting of Power Forward costs through the establishment of a regulatory asset, should be denied.

Summary of the Evidence

DEC's direct testimony

Company witness Fountain testified that Power Forward is Duke's decade-long, \$13-billion grid modernization plan for Duke Energy Progress, LLC (DEP), and DEC, in each of their respective North Carolina service territories. Of the \$13 billion in total Power Forward spend by DEC and DEP on Power Forward programs, DEC plans to spend \$7.7 billion, including \$2.9 billion in capital and \$130 million in operations and maintenance (O&M) expense during the first five years. Witness Fountain testified that the purpose of Power Forward is to improve the performance and capacity of the grid, thereby making it smarter, more resilient, and better able to provide benefits to customers.

DEC Witness Simpson described generally the programs comprising Power Forward, including (1) targeted undergrounding, (2) distribution system hardening and resiliency, (3) self-optimizing grid technology, (4) transmission system improvements, (5) Advanced Metering Infrastructure (AMI)[1], (6) communication network upgrades, and (7) advanced enterprise systems. According to witness Simpson, these programs will primarily focus on projects that accomplish the following goals: improve the reliability and hardiness of the system while making it smarter, build a foundation for customer-focused innovation and new technologies, comply with prescriptive federal transmission reliability and security standards, address maintenance requirements for aging assets, further integrate and optimize intermittent distributed renewable energy generation, and address physical and cyber security, worsening weather, customer disruption, and wear and tear on equipment.

Power Forward investments are planned to supplement customary spend on the transmission and distribution (T&D) grid. To pay for Power Forward programs, DEC proposes that the Commission establish a Grid Reliability and Resiliency Rider (Grid Rider) to "more closely align ... [Power Forward] investments ... with the timeliness of recovery for these investments." Tr. Vol. 6, p. 193. According to witness Fountain, the Grid Rider "would be reset annually based on actual costs, with a true up for any over- or under-recovery." Id. Turning to the mechanics of the Grid Rider, witness Fountain testified that an annual rider proceeding would be held, at which DEC "would provide the specific projects that would be reviewed and approved and the scope of work and things like that." Tr. Vol. 9, p. 78.

On cross-examination, witness Fountain testified that DEC did not initially submit direct testimony regarding the rate impact of the proposed Grid Rider, although he later testified that the net average retail impact would involve a 16% rate increase over the 10-year Power Forward plan.

[1] Although AMI is a Power Forward program, Company witness Simpson testified on rebuttal that DEC is not proposing to recover AMI-related costs through the Grid Rider.

He also testified that DEC plans to invest in Power Forward programs regardless of whether the Grid Rider is approved, but that such investments would likely happen more slowly if the Grid Rider is not approved. Witness Fountain conceded that electricity demand growth is currently "not as much as in prior decades." Tr. Vol. 6, p. 432. Witness Fountain also admitted that Power Forward is part of Duke Energy's corporate policy intended, as quoted in a Duke investor earnings call, "to drive 4 to 6 percent earnings growth." Id. at 434. He acknowledged that Duke Energy represented to its investors that it would pursue distribution infrastructure riders to enhance investment returns, and that the addition of new riders to the ratemaking regulatory framework is intended to "recover [Power Forward] investments in ways that are good for customers as well as help drive shareholder value." Tr. Vol. 8, p. 211. He further conceded that DEC already has made a number of investments without the aid of a rider, including to transition DEC's grid from analog to digital technology through AMR meters.

Company witness McManeus testified that the Grid Rider would allow DEC to recover Power Forward costs on an annual basis after projects are deployed and closed to plant in service, as opposed to the traditional method of recovering costs through a general rate case. She testified that the Grid Rider would help to avoid some dilution of cash flow and earnings, which could slow the pace of the planned investments. The Grid Rider would be set based on "a projection of revenue requirements," combined with a true-up or "Experience Modification Factor" (EMF) for a prior test period. Tr. Vol. 6, p. 271. The Grid Rider would supplement rate changes implemented in general rate cases, with amounts not recovered through the Grid Rider to be included in base rates during the next rate case proceeding. Witness McManeus filed a late-filed exhibit on April 19, 2018, indicating that DEC is seeking to recover $35.2 million through the Grid Rider for 2018 Power Forward spending. Witness McManeus also requested that, in the event that the Commission does not approve the Grid Rider, a regulatory asset be established to defer Power Forward costs for future recovery in a general rate case.

In rebuttal testimony, witness McManeus acknowledged that the Grid Rider would result in "an annual 'mini-rate case' proceeding" limited in scope to costs incurred in connection with Power Forward. Id. at 333. She further testified that the Commission could take action if, as a result of the Grid Rider, DEC's earnings at some future point grew such that they are no longer just or reasonable. Therefore, she testified, the Grid Rider would not "definitively create[] the opportunity for the Company to over earn." Id. at 334. On cross-examination, witness McManeus acknowledged a number of times that the Grid Rider would pass only costs on to ratepayers, but would not account for cost savings resulting from improvements to the grid. She explained that "the reason that the Company requests a rider is to address the issue of regulatory lag that exists in any general rate case proceeding ... that would have the adverse effect of reducing cash flows and earnings." Id. at 440-41. She also conceded that approval of the Grid Rider "would eliminate some regulatory lag, but not necessarily a lot," and would mitigate some regulatory risk for DEC. Tr. Vol. 7, pp. 33-34. Witness McManeus further testified on cross-examination that the planned Power Forward spend described in DEC's filings is not granular data at the project level, but instead is in "large buckets" that correspond to FERC accounting categories. Tr. Vol. 9, p. 74. She conceded that the proposed 2018 Power Forward spending is based on "the same information." Id. at 76.

Company witness Simpson testified that Power Forward is a collection of programs that include projects to upgrade the Company's 'T&D grid. Witness Simpson testified that DEC provides service to approximately 2 million customers in North Carolina, where the Company has more than 100,000 miles of lines and over 1,600 substations. He indicated that in the last four years, the Company has spent $2.6 billion to maintain and upgrade DEC's T&D grid: $1.8 billion in distribution system investments and $770 million in transmission system investments. Distribution investments include connecting new customers, installing lights, adding capacity, and upgrading and maintaining infrastructure, while the Company's transmission investments include addressing capacity and compliance projects, as well as replacing wood poles, obsolete substations, and line equipment. Witness Simpson discussed the need for the Company to continue its customary T&D spending, in addition to Power Forward spend to be recovered through the Grid Rider. He stated that the Company anticipates customary T&D expenditures over the next five years to amount to $3.4 billion.[1]

Witness Simpson testified that Power Forward is necessary because of more frequent convective weather events, aging components, and the addition of more distributed energy resources (DER). While weather is something that the Company has always dealt with in maintaining electric service, witness Simpson stated that more frequent severe weather events drive worsening reliability metrics and that, in his opinion, enhanced hardening of the grid will improve the overall reliability of the grid. Even with more frequent extreme weather events, witness Simpson admitted that the distribution of root causes for outages will remain the same in terms of the number and types of events: 20% for vegetation management related outages, close to 20% for equipment failure, and 6-10% for public accidents, with only the minutes per interruption increasing.

As for the wear and tear on and age of T&D equipment, witness Simpson stated that while Power Forward is not about "chasing aging assets," the current electric grid was built 40 to 60 years ago, and is aging. Tr. Vol. 17, p. 34. Although not a new revelation to the Company, 30% of its T&D assets will be beyond their useful life in the next ten years; not even the best maintenance can stop the cumulative effects of age on the system. Witness Simpson acknowledged that the grid has evolved over decades, and is more hardened today in terms of quality of design than it used to be.

Witness Simpson described the Targeted Undergrounding program as using data analytics to identify line segments with degraded multi-year reliability performance when compared to overhead facilities, in total. Witness Simpson agreed in his rebuttal testimony that taking overhead lines and putting them underground is not a new technology and has been part of utility reliability improvement efforts for years. However, he asserted that the Targeted Undergrounding program is unique because of the data analytics which the Company now employs to determine which individual line segments (versus entire circuits) to underground. Witness Simpson stated that the Company is not talking about a massive undergrounding project but rather targeting specific poorly performing line segments to be undergrounded, which now can be determined in minutes and hours

[1] Witness Simpson originally projected $4.5 billion in customary T&D spend over the next five years. In his rebuttal testimony, however, witness Simpson lowered that projection by $1.1 billion, to reflect the removal of certain costs linked to Power Forward programs, which DEC now proposes to recover through the Grid Rider instead of through customary spend recovered through a general rate case.

as a result of new analytic capabilities, as opposed to the days and weeks it took in the past. Witness Simpson conceded, however, that using data analytics to determine how parts of the grid are performing is not a new concept, and is something that has been evolving for decades, and that will continue to evolve in the future.

According to witness Simpson, the Distribution Hardening and Resiliency program includes retrofitting transformers to eliminate common outage causes, replacing aged or deteriorating cable and conductors, and providing back feed capability to vulnerable communities. Witness Simpson testified that within Power Forward's Distribution Hardening and Resiliency Program, there are four categories of projects that are included in both the Power Forward budget and the Company's customary T&D reliability and integrity and maintenance programs. These four categories of projects are transformer retrofit, underground cable replacement, deteriorated conductor replacement, and targeted pole hardening. Witness Simpson stated that these categories only account for 10% of Power Forward spend and also testified that they constitute the only overlap between the Company's customary spend and Power Forward spend. Witness Simpson argued that these projects should be included in the Grid Rider due to the pace of the expenditures rather than the classification of the investment.

Witness Simpson explained that the Transmission Improvements program includes projects to update and replace transmission system equipment that is likely to fail in the near future, and to add systems that will notify the Company of problems before they result in an outage. The program also will include pole replacement, line rebuilds, substation animal mitigation, and other unspecified physical and cyber security improvements. Witness Simpson stated that this program expedites replacement of obsolete and old design equipment, replacing such equipment with newer equipment that will allow for improved proactive monitoring of the transmission system. Witness Simpson testified that while there is some remote proactive monitoring today, it is not uniform across the system, and the Company has not invested enough in the most current technology to provide a system-wide picture. DEC will consider which substations need upgrades to reach the Company's desired level of functionality. Another category of projects addressing substations is animal mitigation. Witness Simpson conceded that the Company has historically addressed animal mitigation, but contended that many substations still need these upgrades due to national security issues.

Witness Simpson testified that the Self-Optimizing Grid program will add redundant capacity to distribution circuits and substation transformers by replacing existing facilities with larger conductor cable and tying radial distribution circuits together with automated switches to create a distribution network and facilitate two-way power flow. Witness Simpson asserted that this effort also will make the grid "stiffer," allowing for more DER to be connected. Witness Simpson acknowledged, however, that adding redundant lines for back-feed or tie-ins is something that the Company has previously done.

Witness Simpson testified that the investment in Power Forward will be above the Company's customary spend, which he acknowledges is a spending level set by the Company based on projections of the costs necessary to maintain a reliable grid. Witness Simpson itemized the Company's customary distribution capital expenditures over the last four years as follows: 55% for expansion-related work, including serving new customers, lighting installations, and additional capacity; 22% for infrastructure maintenance activities such as pole replacement and underground cable replacement; 23% for targeted reliability improvements to reduce the number and frequency of power outages on the distribution system, including the transformer retrofit program, the sectionalization program, and self-healing technology to automatically isolate the cause of an outage and restore service to customers.

Witness Simpson testified that the Company needs to continue its customary investments in the T&D system to maintain the grid and to add new customers, for which DEC originally budgeted to spend $4.5 billion from 2017-2021. On rebuttal, however, witness Simpson clarified that the estimated customary spend level of $4.5 billion in fact included $1.1 billion that was for grid modernization before Power Forward was developed. The Company then moved that forecasted amount for grid modernization out of the projected plant in service account, where customary T&D expenses are found, and into an account set up for Power Forward expenditures following the announcement of Power Forward. Therefore, DEC now projects customary T&D spend of $3.4 billion, in addition to approximately $3.03 billion of projected Power Forward costs, comprised of $2.9 billion in capital and $130 million for O&M, to be spent between 2017 and 2021. The movement of the $1.1 billion from the customary plant in service account to the Power Forward account was illustrated during the hearing by a project that was part of the original grid modernization fund of $1.1 billion that was in the customary plant in service account. Witness Simpson conceded that the Company had initiated construction of, and placed into service, certain projects that were included in capital forecasting prior to the announcement of Power Forward, but because the cost of the projects had not yet been recovered, they were moved into the Power Forward account to be recovered through the Grid Rider.

On cross-examination, witness Simpson testified that the Company's reliability metrics typically vary from year to year, and conceded that DEC actually saw an improving trend from 2003 to 2012 without the implementation of a Power Forward-type program or a rider. As to the distinction between Power Forward spend and customary spend, witness Simpson testified on cross-examination that a layperson or even an engineer from an electric cooperative may not be able to distinguish Power Forward construction from customary spend construction, but that DEC would know which is which. Witness Simpson further testified that, even where DEC has identified specific amounts for the Targeted Undergrounding program, it has not yet actually decided which locations or how much of the system will be undergrounded. He also testified that DEC would proceed with Power Forward as planned, within the same time frame, even without approval of the Grid Rider.

Alternatively, if the Commission does not approve the Grid Rider, witness McManeus testified that DEC "requests approval to defer as a regulatory asset the O&M (including income and general taxes) and capital-related costs (depreciation and return) associated with [Power Forward] for recovery in a future general rate case proceeding." Tr. Vol. 6, p. 273.

Company witness Pirro testified about DEC's proposed rate design for the Grid Rider. He explained that cost recovery through the Grid Rider, if approved, would follow standard ratemaking principles and would reflect rates that differ by rate class to attribute cost responsibility to each respective class consistent with the COSS supported by witness Hager. However, for reasons set forth hereafter, the Commission is denying DEC's request to establish the Grid Rider, this effectively rendering moot the issues of cost allocation or rate design of the would-be rider.

Public Staff testimony

Public Staff witness Williamson testified that the Public Staff does not support the establishment of the Grid Rider or deferral accounting for Power Forward costs because the Public Staff is not persuaded that all of the components of Power Forward will result in modernization of the grid, as opposed to DEC satisfying its every day statutory obligation to provide adequate and reliable service to its customers. Witness Williamson further stated that much of the Power Forward initiative is designed to improve DEC's outage frequency and duration metrics, which should be part of DEC's every day planning and operations.

Witness Williamson described the Company's proposal as incredibly wide in scope with many disparate parts and elements. Witness Williamson further testified that if the Commission decides to approve a rider for Power Forward, then the Targeted Undergrounding program costs should not be recovered through the rider because the undergrounding of lines for reliability purposes is not new, modern, extraordinary, or outside the scope of normal operations required to provide adequate and reliable service to customers. He went on to state that the Distribution Hardening and Resiliency program also includes many projects that are customary T&D projects, such as cable and pole replacement. The Commission analyzes in more detail the Public Staff's position that Power Forward programs are not unique or extraordinary, and should therefore be considered routine, customary spend to be recovered through a general rate case, in its determinations hereafter.

In 2003, the Public Staff prepared a report on the feasibility of undergrounding the State's entire distribution grid for the North Carolina Natural Disaster Preparedness Task Force (2003 Report). Tr. Ex. Vol. 24, pp. 116-164. The 2003 Report found that undergrounding the entire distribution grid was too costly and recommended instead that each utility (1) identify the overhead facilities that repeatedly experience reliability problems; (2) determine whether conversion to underground is a cost-effective option for improving the reliability of those facilities; and, if so, (3) convert those facilities to underground.[1]

Regardless of whether the Grid Rider is approved, witness Williamson recommended that the Commission require DEC to include in its annual Smart Grid Technology Plan filings, required by Commission Rule R8-60.1, more detailed information on (1) the purpose of each project or category of projects, (2) a schedule of implementation, (3) changes to the schedule that would impact the project's cost or in-service date, (4) project capital and O&M costs (both new and any stranded costs of removed assets), (5) how the Company proposes to recover these costs, and (6) a demonstration of how the project is designed to reduce the outage frequency and duration of individual circuits or other T&D assets affected by the project.

[1] Company witness Simpson admitted that the Company had not performed any undergrounding of distribution lines in response to the Public Staff's recommendation in the 2003 Report.

Public Staff witness Maness stated that any time the Commission segregates one item or a group of items for single-item ratemaking, either through a rider or through deferral accounting, it upsets the regulatory balance in that the "incentives restraining capital investment that are naturally present in the normal aggregated method of ratemaking under [N.C. Gen. Stat. §] 62-133 are relaxed, because the only thing restraining the utility from making these types of investments is the ability of the regulator to devote precious resources to eliminate any imprudent or unreasonably large costs." Tr. Vol. 22, p. 92. In addition, "splitting out major items for single-item ratemaking can make it more likely that the Company will exceed its allowed or appropriate overall rate of return." Id. Witness Maness testified that, as with riders, deferral accounting is an exception to the general method by which rates are normally set for North Carolina's electric public utilities. Rates are normally set on the basis of the aggregate amount of the utility's expenses, revenues, and rate base, and a consideration of the rate of return produced by that aggregation of costs and revenues. Specific components of revenues and costs fluctuate over time, and increases in one cost component can often be offset by decreases in another, thus perhaps mitigating the need for a rate increase to provide recovery of the increase in cost of the first item. He explained that this is one of the reasons that the Commission has previously stated that deferral accounting and riders should be the exception, not the rule. Witness Maness stated that it is important that items set aside for special ratemaking treatment be both extraordinary in magnitude and very unique in type. In addition, witness Maness testified that when a rider or deferral accounting is established, costs intended to be included in the rider should be easily identifiable because of the issues and controversies that may arise regarding specific items of costs and their respective eligibility for special ratemaking treatment. Witness Maness agreed with Public Staff witness Williamson that the types of plant items that the Company is proposing for inclusion in the Grid Rider are vaguely described.

Public Staff witness Parcell testified that DEC's proposed Grid Rider shifts risk from the Company to its ratepayers in that the possibility that certain Power Forward expenses would be disallowed by the Commission would be reduced or eliminated. Witness Parcell quoted a report by Moody's Investors Service, stating in part that it views "the use of rider/tracking mechanisms as positive for credit as they reduce regulatory lag and improve the predictability and stability of cash flow." Tr. Vol. 26, p. 830. Public Staff witness Parcell testified that it is important to consider a rider's effect on the cost of equity for a utility and, accordingly, its rate of return on equity.

Testimony of other intervening parties

CIGFUR III witness Phillips testified that the proposed Grid Rider would shift regulatory risk from investors to customers, and may also eliminate DEC's incentive to prudently manage costs between base rate cases. Additionally, witness Phillips contended that Power Forward costs are not volatile or unpredictable, but rather are within the Company's control and, therefore, are not appropriately recovered through a rider. He stated that DEC has an obligation to provide safe and reliable electric service, and consequently, that Power Forward investments are likely to be made with or without approval of the Grid Rider. Witness Phillips stated that the Company has not demonstrated that the Grid Rider is necessary. As such, he recommended that the Grid Rider be rejected. In the alternative, if the Commission approves the Grid Rider, witness Phillips asserted that the Company's "allowed ROE should be reduced to reflect the reduced business risk that investors will face." Tr. Vol. 26, p. 277. Similarly, Tech Customers witnesses Chriss and Rosa asserted that the Grid Rider would reduce risk for the utility, and that this should be considered when setting DEC's rate of return on equity.

CUCA witness O'Donnell testified that the Grid Rider should be disallowed because, in his opinion, it is too expensive and is likely to harm the North Carolina economy. Witness O'Donnell also testified that DEC has been transparent about the purported benefits, but not the costs, of Power Forward. Witness O'Donnell testified that the Grid Rider is unnecessary because the Company can, and already is, investing in T&D equipment, with the only difference being that it has had to seek recovery of those investments through its general rate cases instead of an annual rider proceeding. Witness O'Donnell testified that DEC's lobbyists unsuccessfully attempted to have legislation enacted that would create the Grid Rider by statute.[1]

Witness O'Donnell stated that the Commission should open a separate docket to investigate the need for DEC's proposed grid investments and to allow for transparency and public involvement in the examination of the following issues: (1) whether Power Forward is needed for reliability purposes; (2) the benefits of Power Forward; (3) the costs of Power Forward; (4) whether Power Forward is cost-effective; (5) how other states are handling grid modernization issues; (6) lessons learned from other states; (7) how North Carolina's renewable energy industry will be affected by Power Forward; and (8) how the rate increases expected under Power Forward and the Grid Rider will affect the State's economy.

Witness O'Donnell further testified that the Company's objective is to drive earnings through Power Forward investments and that the Company seeks to shift risk onto consumers by asking for an automatic forward-looking cost recovery mechanism such as the Grid Rider. In addition, witness O'Donnell expressed concern that the Commission would not retain full regulatory review of Power Forward programs in the Grid Rider's annual proceeding. He stated that during such a proceeding, the ratepayer, and not the utility, would have the burden of proving that DEC's costs were not reasonably or prudently incurred.

While EDF witness Alvarez acknowledged that he is generally supportive of utility grid modernization efforts, he stated that the Commission should deny DEC's request for the Grid Rider until after the Commission has opened a separate proceeding to review, with stakeholder participation, whether Power Forward is warranted for the following reasons: (1) grid modernization investments are very large and distinct in character from business-as-usual investments; (2) Commission review with stakeholder participation will better align DEC's grid modernization investments with Commission and State priorities; (3) applying the "used and useful" standard to assess the prudence of grid modernization investments after the fact is inadequate to protect consumer and environmental interests; (4) disallowance of cost recovery could harm the utility's ability to finance future growth, making it impractical and difficult for the Commission to deny cost recovery once grid modernization investments have already been made; and (5) a Commission review process would likely result in a better cost-benefit ratio for grid modernization programs than if no such review were conducted.

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[1] See Senate Bill 619 (2017).

Kroger witness Higgins testified that the Commission should disapprove the Grid Rider because, in his opinion, infrastructure investments should be evaluated in the context of a general rate case, wherein the totality of DEC's revenues and costs for a given test year are analyzed. He testified that investing in and maintaining the T&D system are fundamental responsibilities for a utility company and, therefore, the related costs should continue to be evaluated as part of a general rate case.

NCSEA witness Barnes testified that the Commission should disapprove the Grid Rider, and instead initiate a separate proceeding to fully investigate Power Forward. Witness Barnes testified that he is concerned about the proposed Grid Rider cost allocation, particularly in light of cost causation principles. Furthermore, of the total revenue requirement to be borne by residential customers, the majority would be recovered as a fixed monthly charge. Witness Barnes stated that the Grid Rider appears to be the first step toward a series of both fixed and variable rate increases for several years to come.

NCSEA witness Golin recommended that the Commission deny the Company's proposal to recover Power Forward costs through either the Grid Rider or deferral accounting. She stated that the Commission should instead open a stand-alone docket to thoroughly define and plan for a modernized grid. In so doing, witness Golin stated that the Commission should require DEC to conduct robust distribution resource planning and take a holistic view of the grid and the technologies that are capable of meeting the grid's needs. This, according to witness Golin, would assure proper forecasting, better evaluate the role of distributed energy resources, and allow for increased transparency and stakeholder input. "Distribution resource planning should be accompanied by thorough cost/benefit analyses that compare several investment pathways to meeting grid investment goals." Tr. Vol. 14, p. 70. Witness Golin recommended that, as part of a new proceeding to examine Power Forward, participants could determine a method and timeline for calculating and publishing the distributed generation hosting capacity of DEC's distribution circuits. Witness Golin also advocated that the Commission open a new docket or stakeholder working group "to assess the impacts of shifts in the Company's investment strategy with the current mechanisms for cost recovery and implications for rate design." Id.

NCSEA witness Golin testified that the Company has not made clear how or why some investments fall under customary spend, and thus are recovered through traditional general rate case proceedings, and other investments fall under Power Forward, and thus would be recovered through the Grid Rider. Witness Golin testified that the Company has also failed to delineate a clear decision-making procedure for how it determined which capital investments are routine, and thus customary spend, and which investments fulfil the goals of the Power Forward initiative, and thus would be Power Forward spend.

Witness Golin further opposed the Grid Rider because, in her opinion, riders allow utilities to obfuscate the risk of large capital investments, whereas DEC's shareholders would continue to bear the risk of investing in these projects if DEC is required to recover Power Forward costs through a general rate case. Witness Golin also opposed the Grid Rider because, in her opinion, it would harm the markets for energy efficiency and distributed energy resources.

Tech Customers witness Strunk testified that DEC failed to distinguish its planned Power Forward spending from customary T&D investments. Describing the significant overlap between Power Forward investments and customary T&D spend, witness Strunk identified the risk that DEC will pursue the recovery of ordinary T&D costs through the Grid Rider. He testified that the Grid Rider threatens to unbalance the regulatory process by moving large capital investments outside of the general rate case process. Witness Strunk testified that the Grid Rider is unnecessary to reduce regulatory lag, in part because both DEC and the Commission have other means of addressing such lag. Witness Strunk testified that DEC's proposal is distinguishable from grid modernization trackers employed in other jurisdictions in that the Grid Rider fails to clearly identify eligible assets, it contains no spending cap on Power Forward investments, and it fails to recognize any offsetting cost savings. Witness Strunk criticized the Ernst & Young study commissioned by DEC as flawed because, in his opinion, the study focused on indirect benefits, excluded analysis of rate impacts, and lacked a clear showing of what DEC contends to be a deteriorating trend in reliability metrics.

DEC's rebuttal testimony

In response to some intervenors who argued that Power Forward is unnecessary and not cost-effective, witness Fountain cited to the study by Ernst & Young, commissioned by DEC, and testified that North Carolina will see net economic benefits from Power Forward's direct capital investments, ranging from $240 million to $1 billion. In response to concerns and questions about the long-term rate impacts of Power Forward, witness Fountain provided DEC Fountain Redirect Exhibit 1, showing that by 2026, Power Forward costs would cause rates to increase by 25.24% for residential customers, 12.39% for commercial customers, and 6.52% for industrial customers.

In response to Public Staff witness Williamson's suggestion that DEC be required to file additional information about Power Forward as part of its annual Smart Grid Technology Plan, witness Simpson testified that the Company is agreeable to the six reporting requirements recommended by the Public Staff, but opposes adding the requirements as a result of this rate case because Commission Rule R8-60.1 affects other utilities besides DEC.

In response to Public Staff witness Williamson's position that the Company has provided insufficient detail to warrant recovery of Power Forward costs through the Grid Rider, witness Simpson testified that the Company has provided economic and technical analyses, in addition to responding to more than 250 data requests regarding its Power Forward plans. Furthermore, in response to several intervenors' concerns, witness Simpson testified that additional detail will be provided, and an ongoing review of Power Forward implementation will occur, through work plans[1] and detailed financial projections that would be subject to intervenor scrutiny and Commission review as part of the annual Grid Rider proceeding. Incurred costs would be subject to a prudency review by the Commission, as would be forward-looking cost projections. Witness Simpson testified that the ten-year duration of Power Forward is preferred because a shorter duration would result in higher prices for labor and material, while a longer duration potentially would involve significant staff turnover, and thus increased training costs, in addition to a slower realization of benefits.

[1] On April 2, 2018, DEC filed a late-filed exhibit containing such plans for 2018 and 2019 only.

Witness Simpson disagreed with Public Staff witness Maness that Power Forward investments are customary spend that would be incurred regardless as part of DEC's continued obligation to maintain its infrastructure in order to provide reliable electric service to its customers. Witness Simpson contended that the costs referenced by witness Maness are maintenance-related costs, not the upgrades and improvements contemplated by Power Forward, which will "convert [DEC's] legacy grid to a next-generation grid that will support our digital society and enable emerging technologies that will benefit customers now and into the future." Tr. Vol. 23, p. 165.

In response to Public Staff witness Williamson's concern that Targeted Undergrounding, in particular, is not a novel or extraordinary investment, witness Simpson conceded:

> ... that burying lines is by no means a novel technology; however, the data resolution and analytical tools that enable the Targeted Undergrounding program are novel—and necessary—to effectively and cost-efficiently know which lines to bury to reduce the maximum number of outages.

Id. at 165-66.

In response to Tech Customers witness Strunk's assertion that the Company has not sufficiently linked its proposed Targeted Undergrounding program to deficiencies in the existing grid, witness Simpson opined that Targeted Undergrounding "will decrease the number of [grid failure] events by as much as 30 to 40 percent." Id. at 177. He opined further that three Power Forward programs combined would improve SAIDI and SAIFI metrics by 40-60%. (Those three programs are Targeted Undergrounding, Hardening and Resiliency, and Self-Optimizing Grid.) Also in response to witness Strunk, witness Simpson testified that the distinction between customary T&D projects and Power Forward projects revolves around "the pace of the expenditures, not the classification of the investment." Id. at 169. Witness Simpson disputed that the Grid Rider would incentivize recovery of customary T&D costs through the Grid Rider, arguing that Power Forward "is comprised of a specific set of projects." Id. at 170. Witness Simpson conceded, however, that some of the projects described as Power Forward "do indeed have similar descriptions as customary [T&D] capital spending." Id. at 180.

In response to EDF witness Alvarez's concerns surrounding the costs of the Targeted Undergrounding program, witness Simpson testified that the per-customer cost referenced by witness Alvarez is inaccurate and that, in any case, the benefits of undergrounding are not limited only to those customers whose service is undergrounded. According to witness Simpson, undergrounding the outlier segments of the grid would eliminate over 50% of overhead system events and over 40% of all system events. Witness Simpson testified that for DEC, the Targeted Undergrounding program will result in an 18% improvement in SAIDI, a 17% improvement in SAIFI, a 36% reduction in non-major event day outages, and a 30% reduction in major event day outages.

In response to several intervenors' concerns that DEC has not sufficiently shown that the existing grid is unreliable enough to warrant the Power Forward spending and resulting rate increase, witness Simpson testified that "the directional trend is clear and consistent—both SAIDI and SAIFI are projected to [worsen] through the year 2026." Id. at 176.

In response to several intervenors' suggestions that a separate proceeding is needed to fully evaluate DEC's Power Forward initiative, witness Simpson disagreed because "[Power Forward] is no different from the grid planning the Company has [sic] done for years, but this initiative is more comprehensive in scope and period than is typical." Id. at 193. In addition, witness Simpson referenced the Technical Workshop that DEP was ordered to hold in early 2018. He again referred to the annual Grid Rider proceeding, which he said would be the avenue through which the Commission and intervening parties could evaluate DEC's Power Forward plans and expenditures.

In response to witness O'Donnell's testimony that DEC's customers are unlikely to see the value in a large rate increase to pay for Power Forward programs, witness Simpson pointed to research data purportedly showing that customers support the idea of grid improvement, even at a somewhat increased cost.[1] Witness Simpson stated that all ratepayers should see positive impacts from Power Forward programs, even after accounting for the increase in electric service rates, through either direct benefits like a reduction in power outages or through indirect benefits, like increased upward pressure on wages and increased economic activity.

In response to several intervenors' testimony contending that the Grid Rider, if allowed, would undermine the Commission's regulatory authority, witness McManeus testified that the Commission has allowed a number of cost-tracking riders, both as directed by the North Carolina General Assembly and in general rate cases, to recover capital and operating costs associated with various items. Although witness McManeus conceded that cost-tracking riders typically are used for regulatory compliance costs or volatile costs outside of the Company's control which comprise a significant component of operating expenses, she stated that riders are not necessarily limited to only these kinds of expenditures. She testified that the Grid Rider would be subject to an annual "mini-rate case" before the Commission, during which the following would allow for sufficient scrutiny of Power Forward costs: stakeholder participation, discovery, evidentiary hearing, true-up mechanism, review and audit of costs by the Public Staff, and expert witness testimony, along with the Company having to bear the burden of proving that the capital or O&M spend was reasonably and prudently incurred. In addition, witness McManeus testified that the Commission would retain authority over the Company's profitability through DEC's total electric earnings quarterly report filings and annual cost of service filings. For these reasons, witness McManeus contended that the costs associated with Power Forward actually would be subject to heightened Commission scrutiny if recovered through the Grid Rider, as opposed to a general rate case.

Witness McManeus specifically addressed intervenor concerns that the use of a rider would allow the Company to over-earn by creating an unbalanced regulatory process. Witness McManeus testified that the costs recovered through the rider would always be limited to actual costs incurred through the use of the EMF mechanism proposed in the Grid Rider. Any amounts over-collected from customers are refunded with interest. DEC witness Hevert also testified that an evaluation of the Company's peers, many of which he stated have rate mechanisms similar to the Grid Rider in place, is necessary to determine whether a Grid Rider would affect DEC's cost of equity or rate of return on equity.

[1] The Commission notes that other information in this same exhibit seems to indicate that 79% of customers would not find grid modernization investments to be reasonable if they resulted in only a 3% rate increase.

Witness McManeus clarified that DEC does not intend to "have the proposed [Grid Rider] supplant the traditional cost based rate cost recovery process." Id. at 336. Rather, according to witness McManeus, DEC is seeking to avoid a 4- to 26-month delay in cost recovery for a high volume of large expenditures involving short construction periods. Witness McManeus stated further that:

> [i]f rate cases did not occur every year, then this lag in the timing of cost recovery is multiplied. In contrast, such lengthy delays have been avoidable for large generation investments, where rate cases are often timed around the estimated completion date of the single large investment.

Id. at 337. Witness McManeus explained that the Company intends to "reflect the financing costs during the construction period through the capitalization of AFUDC." Id. at 338. Only after completion of each project and placing it into service, clarified witness McManeus, would its costs be incorporated into the Grid Rider.

Commission Determinations

The Commission has thoroughly reviewed with care the evidence on the issues surrounding DEC's request for special ratemaking treatment of Power Forward costs; namely, to establish a Grid Rider, or, alternatively, to create a regulatory asset.

While no intervenor generally disagrees with the Company's stated goals of improving and modernizing the grid, the Public Staff and other intervenors unanimously oppose DEC's proposed cost recovery mechanism for these investments. Similarly, while the Commission does not disagree with DEC's stated goals of improving reliability and modernizing the grid, the Commission concludes that it is without statutory authority to allow DEC's request for special ratemaking treatment of Power Forward costs.

As an initial matter, the Commission notes that – with the exception of deployment costs of AMI meters, which DEC is not seeking to recover through the Grid Rider and which are addressed elsewhere in this Order – DEC is not seeking recovery in the instant rate case of Power Forward expenditures incurred during the test year. As such, it would be premature for the Commission to evaluate at this time the prudency or reasonableness of the Company's Power Forward investments. Existing dockets (such as Integrated Resource Planning and Smart Grid Technology Plans), as well as future general rate case proceedings, will provide opportunities for the Commission, at the appropriate time, to consider evidence to evaluate the prudency and reasonableness of Power Forward costs.

A. No exceptional circumstances exist to justify the Grid Rider

DEC in its post-hearing brief, among other things, argues that past cases in which the Commission has created a rider in general rate case proceedings are analogous to the establishment of the Grid Rider in this case, and, therefore, the Commission has the statutory authority to implement the Grid Rider. The Public Staff, AGO, NCSEA, Tech Customers, and other intervenors argue that many of the same cases labeled by DEC as analogous are, in fact, distinguishable, from the issues in the instant proceeding, and, therefore, the Commission does not have the statutory authority to implement the Grid Rider.

As a starting point, the Commission recognizes that certain statutory parameters exist around the authority delegated to it by the Legislature:

> North Carolina Statutes and case law contain explicit limits as to the procedures through which the Commission may revise the rates of a public utility. They are as follows: (1) a general rate case pursuant to G.S. 62-133; (2) a proceeding pursuant to a specific, limited statute, such as G.S. 62-133.2; (3) a complaint proceeding pursuant to G.S. 62-136(a) and G.S. 62-137; or (4) a rulemaking proceeding.

Order Denying Request to Implement Rate Rider and Scheduling Hearing, Docket No. E-7, Sub 849, at p. 18, n.2 (June 2, 2008) (citing State ex. rel. Utils. Comm'n v. Nantahala Power and Light Co., 326 N.C. 190, 195, 388 S.E.2d 118, 121 (1990)). In the instant proceeding – a general rate case pursuant to N.C. Gen. Stat. § 62-133 – the Commission clearly possesses the authority to establish a cost-tracking rider if exceptional circumstances existed to justify such action. Indeed, myriad precedent exists in which the Commission has done just that, even in the absence of an express enabling statute,[1] and the Supreme Court of North Carolina has upheld the Commission's authority to establish a cost-tracking rider when exceptional circumstances, such as a national fuel crisis causing a utility's gas costs to fluctuate unpredictably, warrant such action. See, e.g., State ex rel. Utils. Comm'n v. Edmisten, 291 N.C. 327, 230 S.E.2d 651 (1976) (Edmisten I); State ex rel. Utils. Comm'n v. Edmisten, 291 N.C. 451, 232 S.E.2d 184 (1977) (Edmisten II).

DEC in its post-hearing brief acknowledges that the Commission has in the past recognized the limitations on its authority to create cost-tracking riders in general rate cases; namely, that compelling circumstances must exist to justify special ratemaking treatment.[2] In addressing said limitations, DEC attempts to argue that the magnitude of Power Forward investments, combined with the possibility that regulatory lag of cost recovery for such investments would be detrimental to the Company, are sufficiently exceptional circumstances to justify special ratemaking treatment in the instant proceeding. Accordingly, DEC attempts to argue that the facts in Edmisten I are analogous to DEC's proposed Grid Rider in the instant proceeding. The Commission is unpersuaded by this argument.

Edmisten I approved the use of a fuel adjustment rider in connection with a general rate case. There, the Court noted that the rider at issue "does indeed isolate for special treatment only one element of the utility's cost," but nonetheless approved the additive since it was adopted in connection with a general rate case and was of a nature that merely involved the application of a mathematical formula to the established rates going forward. Edmisten I, 291 N.C. at 340, 230

[1] See, e.g., Order Approving Partial Rate Increase and Allowing Integrity Management Rider, Docket No. G-9, Sub 631, at p. 39 (Dec. 17, 2013) (approving an Integrity Management Rider as part of a general rate case decision); Order Approving Partial Rate Increase and Requiring Conservation Initiative, Docket No. G-9, Sub 499 (Nov. 3, 2005) (approving a Customer Utilization Tracker as part of a general rate case decision); Order Granting General Rate Increase and Approving Amended Stipulation, Docket No. E-7, Sub 909 (Dec. 7, 2009) (approving a Coal Inventory Rider as part of a general rate case decision).

[2] See, Order Approving Partial Rate Increase, Docket No. G-5, Sub 356, at p. 11 (Sep. 25, 1996).

S.E.2d at 659. Notably distinguishable from the facts in the instant proceeding, however, Edmisten I (1) involved a rider that was adopted in the context of exigent circumstances related to the national fuel crisis in the 1970s, and only after the utility in that case demonstrated a clear connection between recovery of its fuel costs and its financial viability; (2) involved a rider that permitted recovery of core operating costs that now are recoverable under express statutory mechanisms; and (3) did not involve forecasted expenditures or evaluations, but rather permitted rate adjustments by application of a mathematical formula. In other words, the Commission established just and reasonable rates and then adopted a going-forward adjustment mechanism that it found necessary to achieve just and reasonable rates based on the exigencies of the energy crisis, which were beyond the utility's control, impacting the utility's expenditures. Crucially, the Supreme Court of North Carolina recognized in upholding the Commission's establishment of a fuel adjustment clause in Edmisten I that the "Commission, cognizant of its primary duty to fix just and reasonable rates, found upon uncontradicted evidence that the only way it could perform this duty under the facts was to permit use of the fuel clause." Id. at 346. Contrast such findings with those in the instant proceeding, in which the Commission finds and concludes that not only did DEC fail to show that the only way to achieve just and reasonable rates would be to allow special ratemaking treatment of Power Forward costs, but also that the greater weight of the evidence supports the conclusion that to allow the Grid Rider as requested would create unjust and unreasonable rates, in the Company's favor. Furthermore, the Commission finds that none of the facts justifying adoption of the fuel adjustment clause in Edmisten I are present in the instant proceeding. Where Edmisten I addressed fuel costs to be incurred by the utility as an essential component of its utility operations, DEC proposes in the instant proceeding to recover projected, future T&D expenditures for projects not yet identified, which are discretionary on its part. Where Edmisten I was decided in the context of wildly fluctuating fuel costs that threatened the utility's financial viability, here, DEC has complete control over the proposed spending, the rate of spending, and the timing of spending on Power Forward programs; it also has full control over its test year and the timing and frequency of when its applications for a general rate increase are filed. For these reasons, contrary to DEC's argument, Edmisten I cannot be read to endorse an end-run around the statutory rate-setting mechanisms; to the contrary, central to the Court's holding in Edmisten I was the Commission's conclusion that the rider was critical to the achievement of the statutorily-prescribed rates.

NCSEA and Tech Customers argue in their post-hearing briefs that a case in which the Commission addressed whether a utility could recover the costs of replacing bare steel and cast-iron mains and services through a rider, when the collected funds would be used to pay for expansion facilities, is analogous to DEC's proposed Grid Rider. See In re Pub. Serv. Co. of N.C., Docket No. G-5, Sub 356, pp. 10-13 (Sep. 25, 1996) (PSNC). The Commission agrees. In PSNC, the Commission explained that its legal authority to authorize riders that have the effect of adjusting rates outside of general rate cases is limited to specific "circumstances involving highly variable and unpredictable expense or volume levels beyond the control of the utility." Id. The Commission rejected the proposed rider in PSNC as unlawful for a number of reasons. First, the Commission found that "the cost had not been shown to constitute an unpredictable portion of ... annual construction expenditures" and that the utility "has control as to how much, how often and when the replacement takes place," meaning that the "expenditures are not highly variable or unpredictable, and they are generally controllable" by the utility. Id. Accordingly, the Commission held that implementation of the rider proposed in PSNC did not fall within its authority to establish.

The Commission noted a number of other concerns, including the possibility that rates would become unreasonable because the rider "would permit PSNC to recover the cost of the replacement mains without recognition of associated decreases in expenses or increases in revenues," a concern that was magnified "by the sheer magnitude and pace of PSNC's replacement program." Id. The Commission further noted that the rider "would require present ratepayers to pay for certain capital improvements as the funds are expended, rather than as the service is provided," which would "cause current ratepayers to subsidize the cost of serving future generations of ratepayers." Id.

Similarly, as argued by NCSEA and Tech Customers, the Commission agrees that a request for an annually adjustable nonutility generator (NUG) rider is analogous to DEC's proposed Grid Rider. See Order Approving Partial Rate Increase, Docket No. E-22, Sub 314 (Feb. 14, 1991) (VEPCO). In VEPCO, NC Power sought approval to recover future NUG expenses that it was contracted to incur over seven years through a NUG rider, with both deferred accounting and true-ups. In rejecting this request, the Commission found that (1) an annual adjustment for purchases of this type outside of a general rate case was not authorized by statute; (2) there was insufficient justification for treating purchased power expenses any differently from any other expense items in the ratemaking process; and (3) that "the NUG rider mechanism would preclude appropriate regulatory oversight of the Company's overall expenses ... because increases in payments to NUGs for additional capacity and energy could be offset by decreases in other cost of service items" that would not be accounted for without a general rate case. Id. at 19. Based on these "policy and legal concerns," the Commission denied NC Power's request.[1] Id. at 20.

DEC's proposed Grid Rider is analogous to the riders rejected by the Commission in PSNC and VEPCO, and is, accordingly, rejected for the same reasons. With the limited exception of federally-mandated reliability standards, DEC has complete control over the amount and timing of Power Forward expenditures, which thus are entirely predictable. DEC, through its request for the Grid Rider, merely seeks to recover more quickly costs that it has historically recovered without the need for a rider. Furthermore, there is no evidence in the record that without special ratemaking treatment for Power Forward costs, DEC would be unable to remain a strong, financially viable company.

The Commission finds and concludes that cost-tracking riders not specifically established by statute are and should continue to be considered an exception to the general ratemaking principles put in place by the General Assembly and this Commission.[2] In the instant case, there is no specific enabling statute or legislative directive requiring the establishment of the Grid Rider, and, therefore, it falls to the Commission to determine whether the circumstances presented by

[1] The Commission also noted that the fuel charge adjustment statute had been narrowly construed by the appellate courts, citing State ex rel. Utils. Comm'n v. Thornburg, 84 N.C. App. 482, 353 S.E.2d 413 (1987). There, the Court overturned the Commission's use of an "experience modification factor" to allow CP&L to recover a past under-recovery of fuel costs. Id., 84 N.C. App. at 490, 353 S.E.2d at 418. In light of the holding of the Court of Appeals, the Commission concluded "that an adjustment to base rates outside a general rate case, for which there is no specific statutory authority, to reflect a true-up of NUG expenses would be found unauthorized." Id. at 19.

[2] It should be noted, however, that there exists a plethora of precedent in which the Commission previously has approved the establishment of non-cost tracking riders in its adjudication of general rate cases, like the matter before the Commission in the instant proceeding. It also has approved the establishment of cost-tracking riders in its adjudication of general rate cases, when exceptional circumstances so warranted.

DEC are exceptional. The Commission finds and concludes that DEC has not presented exceptional or otherwise compelling circumstances to justify special ratemaking treatment of Power Forward costs.

DEC has raised concerns about the regulatory lag for its Power Forward investments. As an initial matter, the Commission notes that regulatory lag is not a new obstacle facing the utilities; rather, it always is present, to a certain extent, in an integrated, investor-owned utility market such as North Carolina. Although DEC in the instant proceeding testified from the perspective of the utility in characterizing regulatory lag as a problem necessitating a solution, it should be pointed out that regulatory lag in certain amounts can give company management an incentive to economize and make more worthwhile investments. Company witnesses Fountain and McManeus stated that while the Grid Rider would alleviate some regulatory lag, it would not be a significant reduction. DEC witness McManeus further stated that the Company did not do an analysis to determine the Company's cash flow with and without the rider; thus, there is no evidence in the record that the Company would be unable to carry out its operations without the requested cost-tracking rider. Therefore, the Commission finds DEC's regulatory lag concerns to be unpersuasive.

For all of these reasons, the Commission concludes that the Company's request for a Grid Rider should be denied. For the same reasons, the Commission concludes that the modified Grid Riders advanced by the Company in its post-hearing brief and Pilot Grid Rider Agreement and Stipulation, respectively, should also be denied.

B. Power Forward costs do not justify deferral accounting through a regulatory asset

Having already determined that DEC has failed to show that exceptional circumstances justify the establishment of a rider to recover Power Forward costs, the Commission now turns to DEC's request, in the alternative, to allow deferral accounting through the establishment of a regulatory asset for Power Forward costs.

As an initial matter, the Commission recognizes that it has in the past "historically treated deferral accounting as a tool to be allowed only as an exception to the general rule, and its use has been allowed sparingly." Order Approving Deferral Accounting with Conditions, Docket No. E-7, Sub 874, p. 24 (March 31, 2009). In addition, the Commission recognizes that it:

> has also been reluctant to allow deferral accounting because it, typically, equates to single-issue ratemaking for the period of deferral, contrary to the well-established, general ratemaking principle that all items of revenue and costs germane to the ratemaking and cost-recovery process should be examined in their totality in determining the appropriateness of the utility's existing rates and charges.

Id.

Turning now to the issues presented in the instant proceeding, the Commission finds and concludes that the reasons DEC says underlie the need for Power Forward are not unique or extraordinary to DEC, nor are they unique or extraordinary to North Carolina. Weather, customer disruption, physical and cyber security, DER, and aging assets are all issues the Company (and all utilities) have to confront in the normal course of providing electric service. The Commission further finds and concludes that while DEC intends to expend significant funds for T&D projects over the next ten years, a number of the Power Forward programs and projects proposed by DEC to be recovered through the Grid Rider are the kinds of activities in which the Company engages or should engage on a routine and continuous basis. Therefore, the Commission must conclude that Power Forward costs, as proposed in the instant proceeding, are not appropriate to be considered for deferral accounting. In reaching these conclusions, the Commission afforded substantial weight to the testimony of Public Staff witnesses Maness and Williamson, NCSEA witness Golin, and Tech Customers witness Strunk; conversely, the Commission was unpersuaded by DEC witness Simpson's contentions that Power Forward programs are new, novel, or extraordinary.

For example, monitoring, maintaining, and replacing aging equipment with like or new components, regardless of the pace at which these activities are conducted, is part of the Company's ongoing obligation to provide adequate and reliable electric service. In addition, the Commission concludes that new data analytics tools that DEC is using to identify the line segments in its Targeted Underground program do not make the program itself an extraordinary or unique modernization project. Undergrounding of lines is not a new concept, as conceded by DEC witness Simpson. Data analytics, as witness Simpson admitted, is neither a new phenomenon, nor is this current iteration of data analytics likely to remain unchanged for the foreseeable future.

Next, the Commission finds and concludes that the Distribution Hardening and Resiliency program contains, in its entirety, projects that also are within the scope of the Company's normal course of operating and maintaining the distribution grid. Of the categories of projects within this program, witness Simpson conceded that the transformer retrofitting, cable replacement, deteriorated conductor replacement/line rebuild, and pole hardening categories are also included in the Company's customary spend budget for the next five years. The Commission finds and concludes that these project categories are clearly within the Company's normal course of business and are not unique nor appropriate to be deferred.

Further, the Commission finds and concludes that the Transmission Improvements program also consists of projects that replace, rebuild, or improve existing transmission equipment. Federal reliability standards change as necessary to ensure national grid stability and reliability. DEC will be required to make the necessary improvements and modifications to its grid in order to remain compliant with such standards now and in the future, just as it has done for decades. Witness Simpson admitted that meeting such federal standards is customary as part of the Company's Business Expansion/Capacity expenditures. Therefore, these programs, too, are within the Company's ordinary course of business, and thus not appropriate for special ratemaking treatment.

Additionally, the Commission finds and concludes that DEC did not provide sufficient information to show how the Company will determine which Self-Optimizing Grid projects should be assigned to and recovered from the interconnection customers who would benefit the most from this capacity-enhancing and grid-strengthening work. Further, whether the majority of the money allocated to this program is for the replacement of lines deemed inadequate to handle new DERs on the system or new back feed or tie-in lines is unclear from the evidence presented. Either way, the Commission finds that back feed or tie-in lines do not represent new work or grid modernization, as witness Simpson testified. In fact, the addition of these kinds of lines is part of normal operations and the Company has added many of them to the grid in areas within its service territory in the past for purposes of ensuring reliable service to its customers.

Lastly, Enterprise Systems and Communications Network Upgrade programs include upgrades to several systems that the Company already uses to enable data acquisition and analytics to help control the grid. The Commission finds, therefore, that these upgrades are no different than many upgrades to other systems that the Company has made in the past and currently is in the process of making. One example is the Customer Connect program, which is an update to the existing customer information system and not included in Power Forward. The Commission considers these upgrades to constitute part of the ordinary evolution of the Company's business.

For all of these reasons, the Commission finds and concludes that DEC has not satisfied the criteria for deferral accounting treatment of Power Forward costs. In order for the Commission to grant a request for deferral accounting treatment, the utility first must show that the cost items at issue are adequately extraordinary, in both type of expenditure and in magnitude, to be considered for deferral. Second, the utility has to show that the effect of not deferring such cost items would significantly affect the utility's earned returns on common equity. Although it was uncontested by any party that DEC's planned Power Forward spend is extraordinary in magnitude, the Commission is unpersuaded that the entirety of Power Forward programs as proposed are unique or extraordinary. Assuming arguendo that all Power Forward programs as proposed were found to be unique and extraordinary, thus meeting the threshold criteria for consideration of deferral accounting, DEC failed to show that the effect of not deferring Power Forward costs would significantly affect its earned returns on common equity.

The Commission appreciates the Company's undertaking to strengthen and modernize its grid and retool other systems, and encourages its efforts. The Commission recognizes that the costs the Company has identified are substantial and that, by and large, the individual projects are of insufficient length to qualify for CWIP or AFUDC before such projects can be completed and placed in service. Without a rider or an order deferring costs, the Company risks an erosion of earnings from regulatory lag. Likewise, these circumstances promote more frequent, costly rate cases.

Nevertheless, the Commission determines as addressed herein that it does not possess the authority to approve the Grid Rider and that the description of projected projects on this record is insufficient to properly categorize customary spend projects, which the Company must undertake to comply with its franchise obligations, from extraordinary Power Forward or grid modernization projects.

With respect to deferral, the Commission acknowledges that, irrespective of its determination not to defer specific costs in this case, the Company may seek deferral at a later time outside of the general rate case test year context to preserve the Company's opportunity to recover costs, to the extent not incurred during a test period. In that regard, were the Company in the future before filing its next rate case to request a deferral outside a test year and meet the test of economic harm, the Commission is willing to entertain a requested deferral for Power Forward, as opposed to customary spend, costs. Should a collaborative undertaking with stakeholders as addressed herein produce a list of Power Forward projects, such designation would greatly assist the Commission in addressing a requested deferral. Were the Company to demonstrate that the costs can be properly classified as Power Forward and grid modernization, the Commission would seek to expeditiously address the request and to determine that the Company would meet the "extraordinary expenditure" test and conceptually authorize deferral for subsequent consideration for recovery in a general rate case.

The Commission can authorize a test for approving a deferral within a general rate case with parameters different from those to be applied in other contexts. Consequently, with respect to demonstrated Power Forward costs incurred by DEC prior to the test year in its next case, the Commission authorizes expedited consideration, and to the extent permissible, reliance on leniency in imposing the "extraordinary expenditure" test.

Having concluded that the Grid Rider and the Company's alternative request to allow deferral accounting of Power Forward costs should be denied, the Commission need not address the related issues, which also were contested by the intervenors, of cost allocation and rate design of the Grid Rider. DEC should seek recovery of its Power Forward expenditures through the traditional general ratemaking process outlined in N.C. Gen. Stat. § 62-133.

C. <u>DEC shall utilize existing Commission dockets to collaborate with stakeholders</u>

The Commission finds and concludes that several of the intervening parties have raised valid concerns regarding the need for additional transparency and detailed information regarding Power Forward. Although the Commission concluded in this proceeding that Power Forward costs do not warrant special ratemaking treatment, the Commission finds and concludes that additional information would be helpful to the Commission, the Public Staff, and to other intervening and interested parties to better understand Power Forward projects, grid modernization in general, and the cost-effectiveness of such programs.

EDF and NCSEA, in their post-hearing briefs, make compelling arguments that the Commission will not repeat here in support of their position that the Commission should establish a separate, generic docket for the purpose of investigating and evaluating the grid modernization plans of all investor-owned utilities in North Carolina. In addition, the Commission notes that EDF provides a comprehensive overview of grid modernization issues and proceedings, as handled in a number of other jurisdictions. Similarly, the Public Staff requests that DEC be required to include in its Smart Grid Technology Plan filings, required by Commission Rule R8-60.1, more detailed information on Power Forward investments.

While the Commission declines to adopt in its entirety either recommendation advanced by the intervening parties with respect to a separate proceeding to further evaluate some of the issues surrounding Power Forward and grid modernization, the Commission recognizes that there could be value in further collaboration between DEC and the intervening parties on how to resolve these issues, which the Commission expects will continue to be raised until such time as the parties can find a solution within our existing statutory framework. With that said, the Commission directs DEC to utilize an existing proceeding, such as the Integrated Resource Planning and Smart Grid Technology Plan docket, to inform the Commission, and to engage and collaborate with stakeholders to address the myriad of issues raised in the context of Power Forward and the Company's proposed Grid Rider.

D. The Pilot Grid Rider Agreement and Stipulation is disapproved

DEC, EDF, the Sierra Club, and NCSEA (Grid Rider Stipulating Parties) contend that their jointly-filed Pilot Grid Rider Agreement and Stipulation Among Certain Parties (Grid Rider Agreement), the contents of which the Commission will not in this Order summarize in detail, addresses several of the concerns raised by the parties regarding Power Forward and the Grid Rider. The Grid Rider Stipulating Parties further contend that a number of concessions were made both by DEC and its counterparties in order to reach the consensus that culminated with the filing of the Grid Rider Agreement. In essence, the Grid Rider Agreement contains a revised Power Forward proposal on a smaller scale, with a shorter duration and limitations on the Company's spending, at least during the initial three-year pilot period. The Grid Rider Agreement represents a hybrid of the Company's initial cost recovery and alternate cost recovery requests, with most costs being recovered through the Grid Rider during the first three years, followed by deferral of such costs thereafter.

While the Commission appreciates the efforts to resolve some of the contested issues surrounding Power Forward and the Grid Rider, the Commission nevertheless concludes that the Grid Rider Agreement must be disapproved. As an initial matter, even if the Commission hypothetically were to find that the Grid Rider Agreement sufficiently mitigates the valid concerns about Power Forward and the Grid Rider as expressed by the intervening parties throughout this proceeding, the Commission nonetheless still would be required to reach the same conclusion that the law as it currently exists does not allow for the establishment of a rider to recover costs that are predictable and within the utility's control.

In addition to the issue of legality, which in and of itself precludes under the instant circumstances the Commission's consideration of the Grid Rider Agreement, the Commission agrees with NCJC et al. and NC WARN that it would constitute poor policy to allow a partial group of interested parties to develop plans for grid modernization through settlement negotiations that address only certain of a number of contested issues, particularly when the Grid Rider Agreement was filed after the close of the evidentiary record in this proceeding, thus precluding entirely the opportunity for cross examination.

In conclusion, the Commission finds and concludes that the Grid Rider Agreement should be disapproved, for many reasons including the rationale for denying the Company's requests for special ratemaking treatment of Power Forward costs in the first place.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 45-49

The evidence supporting these findings of fact and conclusions is contained in the Company's verified Application and Form E-1, the testimony and exhibits of Company witnesses Fallon, Diaz, and McManeus, CUCA witness O'Donnell, Tech Customers witness Kee, and Public Staff witnesses Metz, Maness, and Boswell, and the entire record in this proceeding.

In Docket No. E-7, Sub 819, which has been consolidated with this general rate case, the Company requests Commission approval of its decision to cancel the Lee Nuclear Project pursuant to N.C. Gen. Stat. § 62-110.7(d). In this general rate case, the Company requests permission to move the adjusted balance of the Lee Nuclear Project development costs from CWIP Account 107 to regulatory asset Account 182.2 and to recover the project development costs in rates by amortizing such costs over a 12-year period. The Company also requests that the unamortized balance of such costs be included in rate base to recover a net-of-tax return on the unamortized balance.

DEC witness Fallon testified that in its 2005 and 2006 Integrated Resource Plans (IRPs), the Company identified the need for significant capacity additions by summer 2016 and found nuclear generation to be a least cost supply-side alternative. Tr. Vol. 10, p. 182. In March 2006, DEC announced that it had selected the site for Lee in Cherokee County, South Carolina, to evaluate for possible nuclear expansion. Tr. Vol. 10, p. 183. On September 20, 2006, the Company filed a request in Sub 819 for a declaratory ruling for authority to recover the North Carolina allocable portion of necessary costs and obligations to be incurred through December 31, 2007. On March 20, 2007, the Commission issued its Order Issuing Declaratory Ruling (2007 Order), in which the Commission determined that it was appropriate for DEC to pursue project development work up to $125 million through December 31, 2007, for the Lee Nuclear Project and that DEC could recover the project costs in the manner determined to be appropriate by the Commission and allowed by law.

On January 1, 2008, N.C. Gen. Stat. § 62-110.7 went into effect. This statute provides for Commission review of a utility's decision to incur nuclear project development costs. Under this statute, prior to filing an application for a Certificate of Public Convenience and Necessity (CPCN) in North Carolina or another state, a public utility may request that the Commission review its decision to incur nuclear project development costs. Under N.C. Gen. Stat. § 62-110.7(a), project development costs are defined as:

> all capital costs associated with a potential nuclear electric generating facility incurred before (i) issuance of a certificate under G.S. 62-110.1 for a facility located in North Carolina or (ii) issuance of a certificate by the host state for an out-of-state facility to serve North Carolina retail customers, including, without limitation, the costs of evaluation, design, engineering, environmental analysis and permitting, early site permitting, combined operating license permitting, initial site preparation costs, and allowance for funds used during construction associated with such costs.

Generally speaking, under N.C. Gen. Stat. § 62-110.7(b), the Commission shall approve a utility's decision to incur project development costs if the utility demonstrates that the decision to incur such costs is reasonable and prudent; however, the Commission does not consider the reasonableness or prudence of any specific activities or items of costs until a rate case proceeding. North Carolina Gen. Stat. § 62-110.7(c) provides that reasonable and prudent project development costs shall be included in the utility's rate base and be fully recoverable through rates in a general rate case. However, if the project is cancelled, as has occurred in this case, N.C. Gen. Stat. § 62-110.7(d) allows the utility to recover all reasonable and prudently incurred project development costs in a rate case amortized over the longer of five years or the period during which the costs were incurred, which in this case is 12 years. It should be noted that while N.C. Gen.

Stat. § 62-110.7(c) provides for rate base treatment of project development costs and therefore includes a return, N.C. Gen. Stat. § 62-110.7(d), applicable to cancelled projects, only requires amortization of the costs and does not mention, and certainly does not mandate, a return.[1]

Witness Fallon testified that on December 7, 2007, DEC filed an Application for Approval of Decision to Incur Continued Generation Project Development Costs. Tr. Vol. 10, p. 186. Specifically, DEC sought approval of its decision to incur the North Carolina allocable share of an additional $160 million of Lee Nuclear Project development costs during 2008 and 2009 to maintain the ability to begin nuclear construction to serve customers in the 2018 timeframe as identified in the Company's 2007 IRP. Tr. Vol. 10, p. 187. The Commission approved DEC's request on June 11, 2008 (2008 Order). Tr. Vol. 10, p. 188.

On November 15, 2010, DEC filed an Amended Application for Approval of Decision to Incur Nuclear Generation Project Development Costs seeking approval to incur an additional $229 million of project development costs (later revised to $287 million), for a total of $459 million (including AFUDC) for the period January 1, 2010 through December 31, 2013, to allow Lee Nuclear to remain an option to serve customers in the 2021 timeframe. Tr. Vol. 10, pp. 188-89. The Commission did not approve DEC's request as filed, but in its Order dated August 5, 2011 (2011 Order), the Commission ruled that the nuclear project development costs incurred on or after January 1, 2011, would be subject to a not-to-exceed cap of the North Carolina allocable portion of $120 million and that its approval granted was limited to those nuclear project development costs that must be incurred to maintain the status quo with respect to the Lee Nuclear Project, including DEC's application for a combined operating license (COL) at the Nuclear Regulatory Commission (NRC). Tr. Vol. 10, pp. 190-91. As in the 2008 Order, the Commission allowed DEC to continue provisionally accruing AFUDC, stated that the Company would need to request regulatory asset treatment for any abandoned project development, and required DEC to continue filing semi-annual reports detailing activities and expenditures. Tr. Vol. 10 p. 191. The Commission did not retroactively approve the decision to incur project development costs during 2010. DEC did not seek further project development cost approval orders after the 2011 Order.

DEC witness Fallon testified that the Company incurred costs for the development of the Lee Nuclear Project of approximately $542 million through June 30, 2017. The costs are composed of the following categories: Combined Operating License Application (COLA) Preparation, NRC Review and Hearing Fees, Pre-Construction and Site Preparation, Land and Right of Way Purchases, Supply Chain, Construction Planning and Engineering, Operational Planning, Post COL, and AFUDC ($232 million of the $542 million), as reported in DEC's semi-annual reports to the Commission. Tr. Vol. 10, p. 178; Tr. Vol. 11 p. 19. He stated that in order to "maintain the status quo", DEC exceeded the cap set in the 2011 Order in 2013. Tr. Vol. 10, p. 192. Specifically, witness Fallon indicated that DEC began limiting its activities to only those activities and costs necessary to preserve the option of bringing the plant online around the 2021 target date, did not order equipment, and wound down non-essential site specific work and construction planning

[1] The return at issue here is the return associated with the unamortized balance of a plant that has been abandoned, the costs of which, if not deferred for potential rate recovery through amortization, would otherwise be written off as of the date of abandonment as a loss on the income statement. It is not the return normally accrued on a plant's cost balance during construction, the allowance for funds used during construction (AFUDC), which is included in the definition of "project development costs" set forth in N.C. Gen. Stat. § 62-110.7(a).

activities. Tr. Vol. 10, p. 208. He noted that the Company continued to substantially complete the design of the commercial buildings so that they could be completed in time to meet the 2021 date identified in the IRP. Id. According to witness Fallon, the Company completed its contractual commitments in areas no longer necessary to maintain the status quo and narrowed the scope of work to reduce costs. Further, he indicated that the Company wound down contracts so to preserve the work to be efficiently resumed at a later date. Id.

Witness Fallon also noted that the Company submitted a COLA with the NRC for two Westinghouse AP1000 Pressurized Water Reactors on December 13, 2007. Tr. Vol. 10 p. 180. He noted that a number of factors, many outside the control of DEC, led to a longer licensing period than originally anticipated. Tr. Vol. 10, p. 192. Witness Fallon stated that on December 19, 2016, the NRC issued a COL for the Lee Nuclear Plant allowing DEC to construct the units and to operate them for 40 years. Id. The licenses are renewable for an initial 20-year period and possibly a second 20-year period. Tr. Vol. 10, p. 181. Witness Fallon stated that under the terms of the COL, DEC is not compelled to build and operate the nuclear plant. Id.

Witness Fallon noted that the IRPs between 2006 and 2016 identified Lee Nuclear as a cost effective option to meet the need for base load, but the date of the earliest need for each unit moved to 2026 and 2028 in the 2016 IRP. Tr. Vol. 10, p. 185. He pointed out that through the 2016 IRP, Lee Nuclear Project continued to be least-cost carbon free generation option for customers. Tr. Vol. 10, p. 193. In addition, witness Fallon noted that having the COL for the Lee Nuclear Project would reduce the lead time required to license new nuclear plant at the site. Id. Witness Fallon also indicated that in DEC's latest IRP, the first Lee Nuclear unit would be needed no earlier than 2031, and then only in a carbon-constrained scenario with the assumption of no existing nuclear relicensing. Tr. Vol. 24, pp. 61-62.

In regard to the request to cancel the Lee Nuclear Project, witness Fallon said that since issuance of the COL, the risks and uncertainties in regard to beginning construction have become so great that cancellation was in the best interest of customers. Tr. Vol. 10, p. 195. He noted that in early 2017, Westinghouse announced its plans to exit the nuclear plant construction business, and then, on March 29, 2017, announced its bankruptcy. Tr. Vol. 10, p. 196. Additionally, the first two plants being constructed with AP1000 reactors, in South Carolina (V.C. Summer Project) and Georgia (Vogtle Project), have cost billions of dollars more than originally estimated and have faced significant delays. Id. Witness Fallon stated that the Westinghouse bankruptcy and the decision to stop construction at the V.C. Summer Project led to great uncertainty about the cost, schedule, and execution of construction for future nuclear projects, directly impacting the Lee Nuclear Project. Tr. Vol. 10, p. 198. Therefore, due to these uncertainties and risks, as well as projected low natural gas prices and uncertainty about carbon emission costs, witness Fallon testified that the Company thought that it is not in customers' best interest to construct and operate Lee Nuclear before the end of the next decade. Id. As a result, the Company requests to cancel the project, but maintain the COL. Tr. Vol. 10, pp. 198-99. Witness Fallon indicated that there would be post-COL costs of approximately $700,000 per year so the Company could make annual filings with the NRC and maintain the property. Tr. Vol. 11, p. 72.

DEC witness Diaz testified that in his experience as an NRC Commissioner, including serving as Chairman, he was thoroughly familiar with the AP1000 design and with the NRC licensing process. Tr. Vol. 10, p. 221. In reviewing DEC's decision to pursue the preparation of a COLA in 2005 and submit it to the NRC on December 13, 2007, witness Diaz stated DEC had chosen the optimal path to pursue licensing by using the NRC's new nuclear reactor licensing protocol pursuant to 10 C.F.R. Part 52 Rule (Part 52) (Tr. Vol. 10, p. 223), but that significant time was necessary due to Part 52 being untested. Tr. Vol. 10, p. 233. He noted that when DEC submitted its COLA, the NRC schedule provided for a 42-month period between submission of the application and receipt of the COL, though there was an expectation of a longer period due to the number of applications. Id.

Witness Diaz explained that the process to license the Lee Nuclear Project was delayed for a number of reasons outside of DEC's control, including delays related to the NRC's review of the Yucca Mountain licensing application (Tr. Vol. 10, pp. 235-36), the Waste Confidence Rule (Tr. Vol. 10, pp. 236-37), the Fukushima Dai-ichi accident (Tr. Vol. 10, pp. 238-39.), and the new Seismic Source Characterization. Tr. Vol. 10, p. 240. Additionally, delays occurred as DEC updated its COLA from Rev 16 to Rev 19 of the AP1000 (Tr. Vol. 10, pp. 241-42), changed the location of the reactor based on it improving reactor building stability and being more economical to construct (Tr. Vol. 10, pp. 242-43), added a make-up pond for cooling water due to the limited water in the main cooling source (Tr. Vol. 10, pp. 243-44), and amended the COLA to revise the cooling tower design. Tr. Vol. 10, p. 244. Witness Diaz testified that he believed that DEC acted prudently in making each of these changes and thus the resulting delays were reasonable. Tr. Vol. 10, pp. 241-44. He also noted difficulties associated with using Part 52 licensing that slowed the process, including requests for additional information (RAIs) and generic design issues, as well as design errors in Rev 19, all of which witness Diaz concluded DEC had managed in a reasonable and prudent manner. Tr. Vol. 10, pp. 245-48.

Witness Diaz also reviewed the cost breakdown for the COL and project-related costs for the Lee Nuclear Project and found that they compared favorably to the costs incurred by Florida Power & Light (FP&L) for its Turkey Point Units 6 and 7 COL. Tr. Vol. 10, p. 249. He discussed the disadvantages that would have resulted if DEC had suspended its efforts to license Lee Nuclear, the value of the Lee Nuclear COL, the advantages of DEC's licensing-first approach, and the reasonableness of the selection of the AP1000 design. Tr. Vol. 10, pp. 250-51. Witness Diaz concluded that based on his experience, DEC's approach to licensing and managing the Lee Nuclear Project, and its decision to extend the targeted operation dates, were reasonable and consistent with best practices. Tr. Vol. 10, p. 253. He further determined that the project costs incurred were reasonable and prudent. Tr. Vol. 10, p. 234.

DEC witness McManeus testified that the Company proposed amortizing the accumulated construction work in progress (CWIP) balance related to the Lee Nuclear Project. Tr. Vol. 6, p. 257. In her direct testimony, witness McManeus stated that the adjusted CWIP balance reflecting the actual costs incurred through June 30, 2017 and incorporating estimated additional expenditures through March 31, 2018, was \$353.2 million and \$527.1 million on a North Carolina and system basis, respectively. Id. She noted that non-depreciable land and its associated AFUDC had been removed from the balance. Id. This results in an annual revenue requirement of \$52.6 million, consisting of an annual amortization expense over 12 years of \$29.5 million, and a net of tax return on the unamortized balance of \$23.1 million. Id.

CUCA witness O'Donnell testified that DEC's exceedance of the cap set in the 2011 Order without coming to the Commission for approval of its decision to incur further project development costs was an example of DEC's tendency to "beg forgiveness than to ask permission." Tr. Vol. 18, p. 51.

Tech Customers witness Kee testified regarding the Lee Nuclear Project. Tr. Vol. 18, pp. 164-65. Witness Kee addressed various issues surrounding whether DEC should recover costs incurred to develop the Lee Nuclear Project. Id. at 165-66. Witness Kee recommended that (1) DEC should only recover those costs incurred up to December 31, 2009, if those costs were within the amounts preauthorized by the Commission; (2) DEC should not recover any costs incurred during 2010; and (3) the Commission should completely disallow or significantly limit any recovery of costs incurred between January 1, 2011 and June 2017. Id. at 204-05.

As an alternative to completely disallowing cost after January 1, 2011, witness Kee divided the Lee Nuclear Project costs into two categories: Type 1 and Type 2. Id. at 181. Type 1 costs are "related to the NRC review of the Lee COL application." Id. Type 2 activities are "at most, indirectly related to the NRC COL review process, but were undertaken in preparation for the eventual construction and operation of the Lee nuclear project." Id. at 182. Witness Kee posited that Type 1 activities fall within the meaning of "maintain the status quo" under the 2011 PDO, and Type 2 activities represent expenditures beyond the status quo. Id. at 181. His alternative recommendation was to allow only those costs after January 1, 2011 that relate to Type 1 activities and are less than the amount approved in the 2011 PDO. Id. at 205.

Public Staff witness Metz testified regarding the Company's request for cancellation of the Lee Nuclear project and recovery of the project development costs. He noted that the Public Staff hired as a consultant, Global Energy & Water Consulting, LLC, a firm with extensive experience with nuclear construction activities and NRC application processes, to (1) review the details of all costs charged to all the capital accounts assigned to engineering, licensing, and regulatory compliance for the Lee Nuclear Project; (2) review the decisions to begin, continue, and cancel the project, as well as issues with the AP1000 design, Westinghouse, and Westinghouse's owner, the Toshiba Corporation; (3) review DEC's project planning decisions; (4) compare the costs incurred to those of other utilities; and (5) identify any costs that were not reasonably or prudently incurred. Tr. Vol. 23, pp. 31-32. The Public Staff also reviewed the activities and costs internally. Tr. Vol. 23, p. 32. Based on the Public Staff's review as assisted by the consultants, the Public Staff found that with one exception involving design costs for a visitors' center, the costs incurred (not including AFUDC, which was reviewed by Public Staff witness Maness) were reasonably and prudently incurred based on information known at the time. Tr. Vol. 23, pp. 32-33. Witness Metz recommended that costs incurred for the architectural and engineering design of a visitors' center be disallowed on the basis that under the dictates of the 2011 Order, the costs did not directly support the COLA process at the NRC and were not necessary to maintain the status quo at that time. Tr. Vol. 23, pp. 33-34. This recommendation results in a disallowance of $507,009 on a system basis, exclusive of AFUDC. Tr. Vol. 23, p. 36.

Public Staff witness Maness testified that on behalf of the Public Staff, he investigated the reasonableness of the accrual of the AFUDC costs included in DEC's project development costs, and particularly DEC's dates for beginning and ending the accrual of AFUDC. Tr. Vol. 22, p. 100. Based on his review, witness Maness found the date on which DEC began accruing AFUDC to be reasonable, but recommended that AFUDC accrual end as of December 31, 2017, instead of the May 1, 2018, date estimated by DEC. Id. He testified that under FERC Accounting Release No. 5, AFUDC accruals must cease if construction is suspended or interrupted. Tr. Vol. 22, p. 101. Based on discussions between DEC and the Public Staff, witness Maness stated that the Company had confirmed that work on the Lee Nuclear Project had ended as of December 31, 2017, and that the Company had ceased accruing AFUDC at that time. Tr. Vol. 22, p. 102. He noted that removal of the estimated 2018 AFUDC from the costs proposed for Lee Nuclear recovery resulted in a $9 million adjustment. Id.

Public Staff witness Boswell contended that the Commission should adhere to its longstanding position that no adjustment should be allowed which would effectively enable the Company to earn a return on the unamortized balance of the construction costs of a nuclear plant that had been abandoned. Tr. Vol. 26, p. 140. She argued that the Commission has found in past cases that this treatment fairly allocated the loss between the utility and customers, and that customers should not bear all the risk of the cancelled plant. Id.

In his rebuttal testimony, witness Diaz disagreed with witness Kee's stratification of costs into two categories on the basis that both types of costs were necessary for the Company to adhere to the 2011 Order and to have the Lee Nuclear option available to meet the dates for need projected in DEC's IRPs. Tr. Vol. 26 p. 181. He noted that DEC could not have obtained the COL without exceeding the limits in the 2011 Order. Tr. Vol. 26, p. 182. Witness Diaz further testified about the value of the COL obtained by DEC. Tr. Vol. 26, pp. 186-88.

In rebuttal, Company witness Fallon testified that the Company did not oppose the recommendation of witness Maness to end the accrual of AFUDC for Lee Nuclear at December 31, 2017. Tr. Vol. 24, pp. 32, 33. In regard to witness Metz's proposed disallowance for the costs associated with the architectural and engineering of a visitors' center, witness Fallon explained the reasons why DEC sought to construct a visitors' center as one of the buildings with early design work, but conceded that witness Metz's conclusion to recommend a disallowance for these costs was reasonable. Tr. Vol. 24, p. 34.

Witness Fallon opposed the recommendation of Public Staff witness Boswell that DEC should not receive a return on the unamortized balance of the Lee Nuclear costs and associated accumulated deferred income taxes (ADIT). He noted that while witness Boswell referred to the costs of Lee Nuclear as having been prudently incurred, the financing costs of the unamortized balance were also prudently incurred costs. Tr. Vol. 24, pp. 34-35. Witness Fallon pointed out that N.C. Gen. Stat. § 62-110.7 does not prohibit DEC from receiving a return on the unamortized balance of prudently incurred costs. Tr. Vol. 24, p. 36. He argued that witness Boswell had not considered the specific facts of this case in making her recommendation of no return, including the fact that the Company had obtained a COL, the highly dynamic energy future, the advantages of maintaining fuel diversity, and the uncertainty of nuclear relicensing. Tr. Vol. 24, pp. 37-39. Witness Fallon also detailed the steps the Company took to mitigate the risks of the project. Tr. Vol. 24, p. 39.

In regard to the testimony of Tech Customers witness Kee, witness Fallon disagrees with the contention that all nuclear development costs must be approved or authorized in advance under

N.C. Gen. Stat. § 62-110.7 to be recoverable. Tr. Vol. 24, p. 40. Witness Fallon noted that while the project development orders (PDOs) issued in Sub 819 have specific authorizations, they do not foreclose the possibility that DEC may recover costs outside of the strictures of those Orders. Tr. Vol. 24, p. 41. He also stated that utilities are permitted, but not required, to seek approval of the decision to incur project development costs under N.C. Gen. Stat. § 62-110.7, and that the Commission did not approve DEC's request for approval to incur Lee Nuclear costs in 2010, but it made no finding as to their recoverability. Id. Witness Fallon testified that DEC had exceeded the spending cap set in the 2011 Order. However, he testified that DEC interpreted the 2011 Order as requiring the Company to limit its spending to amounts necessary to preserve the option of building Lee Nuclear so that it would be available to meet the target dates of need set out in DEC's IRPs, including maintaining an active COLA at the NRC. Tr. Vol. 24, p. 44. In order to maintain this active COLA status, witness Fallon explained that DEC had to continue its permitting, pre-construction, engineering, design, construction planning, and operational planning activities to maintain the status quo. Tr. Vol. 24, p. 45. Further, witness Fallon testified that it was necessary for DEC to continue its efforts in many areas to avoid signaling to the NRC that DEC was not actively pursuing the Lee COL, which could have resulted in termination of the review process by the NRC prior to the issuance of the COL. Id.

On cross-examination, witness Fallon identified Tech Customers Fallon Rebuttal Exhibit 1 as an internal presentation made in February 2012 to the Company CEO's staff by himself and the nuclear development staff regarding the future of the Lee Nuclear Project. Tr. Vol. 24, p. 54. The exhibit showed the projected dollars spent that exceeded the limits of PDOs issued by the NCUC and the South Carolina Public Service Commission. Tr. Vol. 24, p. 56. The presentation indicated that filing for a subsequent PDO would put the NCUC in a "difficult position" as James E. Rogers, the CEO during the 2011 proceeding had testified that DEC would not proceed with Lee Nuclear unless the North Carolina General Assembly had enacted legislation allowing DEC to receive CWIP costs through a specified cost recovery process.[1] Tr. Vol. 24, p. 57. The presentation also noted the negative impact on the Lee Nuclear business case of projected low natural gas prices. Id. The presentation also pointed out the negative effect on the Lee Nuclear project that would result from a rejection of a further request for approval to incur nuclear development costs. Tr. Vol. 24, p. 58. Based on these factors, Nuclear Development recommended in 2012 that the Company not seek an additional PDO. Id. The Company also had another internal meeting in early 2013 where it again decided against pursuing a further PDO for similar reasons, as well as delays occurring with the NRC process. Tr. Vol. 24, pp. 62-64. Following the merger of Duke Energy Corporation and Progress Energy, Inc., a third senior management meeting was held in November 2013 to consider whether to pursue a PDO. Tr. Vol. 24, pp. 65-66.

Witness Fallon agreed that one of the purposes of N.C. Gen. Stat. § 62-110.7 is to help alleviate some portion of the risk that certain costs incurred for nuclear project development activities may be found to be imprudent. Tr. Vol. 24, p. 71. Witness Fallon stated that he was the Company witness supporting DEP's request in its recent rate case to recover COLA costs of approximately $45.3 million for its cancelled Harris Nuclear project. Tr. Vol. 24, p. 74. In that case, DEP did not seek a return on the unamortized balance of the costs for the COLA for the

[1] This testimony by Mr. Rogers was one of the factors cited by the Commission in its decision to issue only a limited approval of DEC's decision to incur project development costs in the 2011 Order.

cancelled Harris Nuclear project. Tr. Vol. 24, p. 75. However, witness Fallon argued that the Harris Nuclear and Lee Nuclear projects are different because DEC had sought approval for the Lee Nuclear Project under N.C. Gen. Stat. § 62-110.7, the Lee Nuclear project had progressed beyond the development stage to receipt of a COL, and that the investor risk differed due to the amount of spending and the scope of activities. Tr. Vol. 24, pp. 75-77. Finally, witness Fallon acknowledged that while having the COL means that DEC may use its option to build the Lee Nuclear plant when the time is right, the time may never be right. Tr. Vol. 24, p. 82.

In her rebuttal testimony, Company witness McManeus noted that the Company did not oppose the recommendations of Public Staff witness Metz to remove certain costs associated with the design of a visitors' center from the Lee Nuclear costs or Public Staff witness Maness to remove AFUDC for the months after December 2017. Tr. Vol. 26, p. 310. She testified that the Company did oppose the adjustment recommended by Public Staff witness Boswell to remove the unamortized balance of deferred project development costs and the associated ADIT from rate base, thereby preventing the Company from earning a return on the unamortized balance. Id. Witness McManeus argued that the Commission should consider that the Lee Nuclear project costs were financed by investors and should appropriately be in rate base. Tr. Vol. 6, p. 311. According to witness McManeus, if the Commission determines that the Lee Nuclear costs were incurred prudently, it should include those costs in rate base, thereby allowing the Company to earn a return on the unamortized balance. Id. On cross-examination, witness McManeus agreed that the decision to allow the Company to earn a return on cancelled plant was within the Commission's discretion. Tr. Vol. 8, p. 232. She further agreed that once the amortization of Lee Nuclear was completed, it would be inappropriate for the Company to re-establish the asset and thus recover it from the customers again. Tr. Vol. 26, p. 110. She indicated that if recovery of Lee Nuclear costs were allowed, DEC would have a regulatory asset that would be amortized over the period allowed, and then in DEC's next rate case, the balance of the regulatory asset would be addressed. Id.

Discussion and Conclusions on Lee Nuclear

A. Recovery of Costs

In regard to specific items of cost, the Commission agrees with Public Staff witness Metz that costs incurred for the architectural and engineering design of a visitors' center did not directly support the COLA process at the NRC and were not necessary to maintain the status quo at that time as directed by the 2011 Order. As such, these costs should be disallowed. The Commission also agrees with Public Staff witness Maness that accrual of AFUDC on the project should have stopped after all substantive work on the project had come to an end by December 31, 2017. As noted above, DEC did not contest either of these two proposed adjustments.

As noted above, Tech Customers witness Kee recommended disallowance of the costs incurred in 2010 and the costs in excess of the limit set in the 2011 Order. In its proposed order, Tech Customers supports this position. NC WARN supports the recommendations of witness Kee in its brief. In its proposed order, the AGO argues that given the evidence challenging the reasonableness and prudence of DEC's expenditures on and after January 1, 2011, and DEC's failure to provide details sufficient to identify what it would have cost to maintain the status quo, the costs incurred on or after January 1, 2011 for new development activities should be disallowed.

The Commission finds that witness Kee's recommendation appears to be based on a misinterpretation of N.C. Gen. Stat. § 62-110.7. First, N.C. Gen. Stat. § 62-110.7(b) includes the word "may" indicating that it is at the utility's discretion whether it will seek to incur approval of its decision to incur nuclear project development costs under the statute. Costs for which preapproval is not sought, such as those in 2010, are still appropriately considered in a general rate case proceeding under N.C. Gen. Stat. § 62-133, including the prudence of the decision to incur the costs. Similarly, the costs that were incurred outside the cap set in the 2011 Order are appropriately considered in this proceeding. N.C. Gen. Stat. § 62-110.7 provides a utility approval only of its decision to incur nuclear development costs under the circumstances at the time of the decision. No particular costs are approved or found to be reasonable, and circumstances can change after issuance of the approval making it no longer reasonable to incur costs. As discussed by DEC witness Fallon, DEP elected to pursue development of its Harris Nuclear project without obtaining approval under N.C. Gen. Stat. § 62-110.7 and the Commission approved recovery of the costs of the COLA in DEP's recent rate case without regard to whether DEP had received approval under N.C. Gen. Stat. § 62-110.7. The Commission further disagrees with witness Kee that what he categorizes as Type 2 costs should be disallowed because they were not necessary to maintain the status quo. The Commission finds that, except as discussed above in regard to the visitors' center and AFUDC, the costs were reasonably and prudently incurred to maintain the status quo and ensure that Lee Nuclear would be an option for the dates of projected need in DEC's IRPs.

B. Cancellation of the Lee Nuclear Project

The Company has stated that it seeks Commission approval to cancel the Lee Nuclear Project. The Commission agrees with DEC witness Fallon that the risks and uncertainties in regard to beginning construction of the Lee Nuclear Project, including the Westinghouse bankruptcy, issues with Toshiba, the cancellation of the Summer project, overruns and delays at the Vogtle project, as well as natural gas prices and potential carbon emissions regulation, have become so great that cancellation is in the best interest of customers. Further, DEC's 2017 IRP does not show a need for the first unit until 2031, and then only under a number of assumptions.

While no party expressed opposition to DEC's decision to cancel the Lee Nuclear Project, in their proposed orders, the Tech Customers and the Public Staff question the authority of the Commission to cancel the project noting that the Commission had never granted the project a CPCN under N.C. Gen. Stat. § 62-110.1, nor had any other state approved the project. While there may be merit to such observations, suffice it to say, the Commission finds and concludes that adequate justification exists to support cancellation of the Lee Nuclear Project and that DEC's decision to cancel the project is reasonable and prudent and in the public interest.

C. Return on Unamortized Balance

The Commission is also in agreement with Public Staff witness Boswell's position concerning the Company's request to earn a return on the unamortized balance of the costs. Company witness McManeus acknowledged on cross-examination that in the cases of Duke Power Co., Docket No. E-7, Sub 338, 72 N.C.U.C. 173 (Nov. 1, 1982); Carolina Power & Light Co., Docket No. E-2, Sub 461, 73 N.C.U.C. 114 (Sept. 19, 1983); and Carolina Power & Light Co., Docket No. E-2, Sub 481, 74 N.C.U.C. 126 (Sept. 21, 1984), all involving abandoned nuclear plants, the Commission had refused to allow a return on the unamortized balance. She further stated that she knew of no other case decided since 1982 approving a return on the unamortized balance; and neither the Public Staff nor the Commission has been able to identify any such case. The Commission's 1982-84 decisions denying a return on the unamortized balance of nuclear plant costs have been reaffirmed in cases such as Carolina Power & Light Co., Docket No. E-2, Sub 537, 78 N.C.U.C. 238 (Aug. 5, 1988), aff'd in part, rev'd in part on other grounds, and remanded sub nom. State ex rel. Utils. Comm'n v. Thornburg, 325 N.C. 484, 385 S.E.2d 463 (1989). See also, State ex. rel. Utils. Comm'n v. Thornburg, 325 N.C. 463, 480-81, 385 S.E.2d 460-61 (1989), which held that the Commission had the legal authority to deny a return on the unamortized balance of nuclear cancellation costs.

In the Commission's judgment, the decisions it has reached on this issue since 1982 are correct and should be followed in this case. The Commission has repeatedly decided that the loss experienced upon the cancellation of a nuclear plant should be shared between the shareholders and the ratepayers. As the Commission stated in its Order in Duke Power Co., Docket No. E-7, Sub 358, 73 N.C.U.C. 255, 266 (Sept. 30, 1983), when addressing the loss associated with the Cherokee Nuclear Plant (Lee's precursor abandoned nuclear project at the same site):

> It would be inequitable to place the entire loss of expenditures that were prudent when made on the utility. Thus, amortization should be allowed. However, on the other hand, the ratepayer must not bear the entire risk of the Company's investment. A middle ground must be found on which the Company bears some of the risk of abandonment and the ratepayer is protected from unreasonably high rates.

See also, In re Carolina Power & Light Co., Docket No. E-2, Sub 461, 55 P.U.R. 4th 582, 601 (1983).

Accordingly, regulatory commissions in North Carolina and many other states have allowed the utility to recover the costs of an abandoned plant through amortization, while excluding the unamortized balance from rate base. In this way, a fair allocation of the losses is accomplished: the ratepayers are required to bear the losses resulting directly from the cancellation, while the shareholders must absorb the loss associated with the delay in receiving their compensation. This is the policy that the Commission adopted in Duke Power Company's case in November 1982; we have consistently adhered to it in the years since, and we see no valid reason to depart from it now.

The Commission does not agree with witness Fallon that the Company's receipt of three PDOs should factor into whether it should receive a return. The Commission notes that the Company chose to act without a PDO in 2010 and after the second quarter of 2013, over one third of the period of the project, thereby acting outside of the requirements of and protections offered by N.C. Gen. Stat. § 62-110.7. While N.C. Gen. Stat. § 62-110.7 is permissive and the Commission has found that the Company's Lee Nuclear incurred costs and activities were reasonable and prudent (except as discussed above in regard to the visitors' center and AFUDC) regardless of whether it received PDOs for the entire period, DEC's receiving Commission approval of some of its decisions to incur nuclear project development costs does not factor into the Commission's exercise of its discretion under N.C. Gen. Stat. § 62-110.7(d) as to whether the Company should get a return on the unamortized balance of the Lee Nuclear costs.

Additionally, the Commission rejects the contention by witness Fallon that having obtained a COL should merit shifting the entire burden of cost and risk to ratepayers. While the Commission agrees that the COL has value, that value will only be realized if the plant is built. Pursuant to the 2017 IRP, that possibility would occur only under very limited circumstances. Moreover, there is a cost to maintaining this option that DEC will likely be requesting ratepayers to bear in future rate cases.

Further, in Docket No. E-2, Sub 1035, DEP sought a deferral on its Harris COLA costs, but requested no return on the unamortized balance, citing State ex rel. Utils. Comm'n v. Thornburg, 325 N.C. 463, 385 S.E.2d 451 (1989) (holding that NCUC had authority to allow CP&L to recover capital investment in cancelled plants through 10-year amortization, with no return on the unamortized balance); Order Approving Stipulation and Deciding Non-Settled Issues, Docket No. E-7, Sub 828 (December 20, 2007) (treating GridSouth costs as an abandonment loss and allowing recovery of prudently-incurred costs over a 10-year amortization period, with no return on the unamortized balance); and Order Approving Partial Rate Increase, Docket No. E-7, Sub 358 (September 30, 1983) (allowing Duke Power to recover abandonment loss due to Cherokee Nuclear Units 1-3 cancellation over a 10-year amortization period, with no return on the unamortized balance). The Commission sees no reason to treat the Lee Nuclear Project differently, regardless of the difference in costs or achievement of a COL.

The Commission also notes that in its proposed order, for the first time in this proceeding, DEC argues that the Commission specifically made a distinction that it would treat the Lee Nuclear project development costs differently for purposes of ratemaking in its 2007 Order and that the General Assembly codified that distinction when it did not prohibit a return on the unamortized balance of prudently incurred costs during the amortization of a cancelled plant in N.C. Gen. Stat. § 62-110.7(d). In fact, DEC now argues that the principles of statutory construction that it weaves between N.C. Gen. Stat. § 62-110.7(c) and 110.7(d) support the Company's position that it should earn a return on the costs invested to develop the Lee Nuclear Project, even though it is cancelled. With respect to DEC's argument in these regards, the Commission simply disagrees. First, the Commission can unequivocally state that nothing in its 2007 Order spoke directly to or implied support for the Company to be able to earn a return on the unamortized balance. The Commission also notes that DEC's own witnesses testified that it was within the Commission's discretion whether or not to allow a return on the unamortized balance. Further, since the Lee Nuclear Plant is now cancelled, the term "...the potential nuclear plant..." that appears in N.C. Gen. Stat. § 62-110.7(c) is no longer applicable to the issue at hand, and N.C. Gen. Stat. § 62-110.7(d) is now controlling and there is no mention in N.C. Gen. Stat. § 62-110.7(d) regarding a return on the unamortized balance. In addition, although not applicable here, N.C. Gen. Stat. § 62-110.6(e), regarding rate recovery for construction costs of out-of-state electric generating facilities that are cancelled, directs the Commission to provide cost recovery as provided in N.C. Gen. Stat. § 62-110.1(f2) and (f3). N.C. Gen. Stat. § 62-110.1(f2) and (f3) include the provision that "...the Commission shall make any adjustment that may be required because costs of construction previously added to the utility's rate base pursuant to subsection (f1) of this section are removed from rate base and recovered in accordance with this subsection." (emphasis added) This analogous portion of the statute makes clear that costs associated with canceled plant are not part of rate base and the Commission determines to interpret N.C. Gen. Stat. § 62-100.7 which is silent as to the issue similarly. In summary, the Commission has carefully reviewed DEC's contentions that any prior Commission order or the ratemaking treatment prescribed in N.C. Gen. Stat. § 62-110.7(c) is supportive, applicable, or controlling with respect to allowing a return on the unamortized balance and disagrees.

Finally, although not discussed in the record, the Commission notes that during the entire 12-year period in which DEC incurred and funded the project development costs, it was allowed to accrue an AFUDC return. In fact, AFUDC comprises over forty percent of the total Lee Nuclear project development cost. The accrual of the AFUDC has already provided DEC, or its investors, a return on all non-AFUDC costs incurred during the past 12 years and that return will be recovered in cash from ratepayers over the next 12 years as the total allowed cost is amortized. The Commission concludes this consideration is supportive of its decision to require a fair allocation of costs for the cancelled plant between the Company and its ratepayers by denying a return on the unamortized balance during the 12-year amortization period.

D. Summary of Conclusions on Lee Nuclear

In summary, the Commission concludes in regard to the Lee Nuclear Project that the costs were reasonably and prudently incurred except the costs of the architectural and engineering design of a visitors' center and AFUDC after December 31, 2017. The Commission finds that it is reasonable and prudent for the Company to cancel the Lee Nuclear Project at this time. Finally, the Commission holds that the costs of the Lee Nuclear Project should be recovered through amortization over a period of 12 years, with no return on the unamortized balance.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 50-51

The evidence supporting these findings and conclusions is contained in the Company's verified Application and Form E-1, the direct testimony of Public Staff witnesses Robert Hinton and Michael Maness, the rebuttal testimony of Company witnesses Stephen De May and David Doss, and the entire record in this proceeding.

Background of the Nuclear Decommissioning Trust Fund

Every nuclear power plant owner in the United States is required under rules promulgated by the NRC to ensure that the nuclear plants it owns and operates are properly decommissioned when they reach the end of their useful lives. Monies to pay for decommissioning activities are collected from customers in rates and deposited in trust funds, where they are invested and earn returns.

DEC operates seven nuclear-powered units at three different power plants. Funds the Company has collected in rates from customers over the years, pursuant to specific authorizations contained in rate orders issued by this Commission, have been deposited in nuclear decommissioning trust funds (while each nuclear unit has its own decommissioning funds held in trust, for ease of reference, they are herein referred to collectively as the (NDTF)) pursuant to the NRC rules. Under those rules, as well as rules promulgated by the IRS, NDTF funds are to be used exclusively for nuclear decommissioning activities, which include license termination, dealing with spent fuel, and site restoration.

Through procedures described in greater detail below, every five years the Company engages a third-party consultant to perform a site-specific study and prepare a site-specific estimate of the decommissioning costs which will be necessary to decommission the units DEC owns and operates. Based upon that study, the Company files a report setting out those estimates (the Decommissioning Cost Study Report, or Cost Report). Every five years, based upon financial assumptions provided by additional third-party consultants, the Company models NDTF balances at the time of decommissioning and files a report in a prescribed format (the Decommissioning Cost and Funding Report, or Funding Report) detailing the total revenue requirement/decommissioning expense needed to fund its decommissioning obligations.

The Company last filed a Cost Report and Funding Report in 2014. Those Reports indicated that based upon projected decommissioning costs and projected NDTF balances (both projected decades into the future, inasmuch as decommissioning will not take place until decades into the future), the NDTF was adequately funded. Tr. Vol. 12, p. 48. Accordingly, the Company concluded that, at least as of that time, the Company need not collect in rates any cost with respect to nuclear decommissioning, and that additional contributions to the NDTF need not be collected from customers. The Company has not collected any NDTF contributions from customers since January 1, 2015.

Thereafter, with the joint support of the Company and the Public Staff, the Commission implemented a decrement rider as of July 1, 2015, reducing the Company's revenue requirements in order to reflect nuclear decommissioning costs at $0. In this rate case, based upon standard escalations of the 2014 Cost Report and 2014 Funding Report, the Company again concluded that the NDTF was adequately funded and determined that it need not collect any nuclear decommissioning expense as part of its cost of service.

In this docket, the Public Staff has taken the position that the NDTF is overfunded by $2.35 billion. The Public Staff asserts that in order to redress this supposed overfunding, the Company should be required to refund the excess by assigning to nuclear decommissioning "expense" a value of ($29 million) – that is, negative $29 million – per year. Acknowledging that the funds in the NDTF are untouchable for this purpose, in that they are to be used solely for decommissioning, the Public Staff developed a proposal by which the funds would be refunded to customers through the mechanism of a "loan" to be "repaid" after decommissioning is complete.

DEC contends the NDTF is not "overfunded." Further, as discussed below, under generally accepted accounting principles (GAAP), the Company believes it would have to write off the proposed "loan" inasmuch as it would not have a probable and acceptable path to repayment. DEC also argues that the approach recommended by the Public Staff is retroactive in nature, thus violating the prohibition against retroactive ratemaking in North Carolina. Finally, DEC submits prior orders of this Commission including prior agreements between the Public Staff and the Company appropriately provide for addressing surplus decommissioning funds – if any – at the conclusion of decommissioning.

Summary of Evidence Relating to NDTF

On July 25, 1988, the Commission opened Docket No. E-100, Sub 56 (Sub 56 Docket) to consider issues relating to decommissioning cost and funding for nuclear power plants owned and operated by the public utilities under its jurisdiction, namely Carolina Power & Light Company (now DEP), Duke Power Company (now DEC), and North Carolina Power (now Dominion North Carolina Power).[1]

On November 3, 1998, the Commission issued an Order in the Sub 56 Docket (Order Approving Guidelines (DEC – Maness Cross-Examination Ex. 1, Tab 1)), in which it adopted guidelines for the determination and reporting of nuclear decommissioning costs (the Guidelines). The Guidelines establish the five-year cycle of report filing described above, with respect to both the Cost Report, where the Company estimates decommissioning costs, and the Funding Report, detailing the total revenue requirement/decommissioning expense needed to fund the Company's decommissioning obligations. Further, as Public Staff witness Maness confirmed, the Public Staff is provided a 90-day period to issue discovery and investigate the cost and funding analysis the Company sets out in its Reports. Tr. Vol. 22, pp. 185-86. The Public Staff then has 90 days to prepare and file its own report. Id. In accordance with the Guidelines, the Public Staff has routinely reviewed the Company's decommissioning Cost Reports and decommissioning Funding Reports.

In the Company's last rate case, it proposed that nuclear decommissioning expense be $35 million. See 2013 DEC Rate Order, p. 110; DEC – Maness Cross Examination Ex. 1, Tab 3. The Public Staff, through witness Hinton, proposed an adjustment to reduce that expense to $14.6 million, which the Company accepted and the Commission ordered. Id. at 111. In the following year, the Company's five-year Cost Report/Funding Report cycle required it to file those Reports. As noted above, the Company concluded in connection with those filings that the NDTF was adequately funded and that a decrement rider to reduce nuclear decommissioning expense to $0 as of January 1, 2015 was warranted, which the Commission ultimately ordered. DEC – Maness Cross Examination Ex. 1, Tabs 2 and 4; Tr. Vol. 22, pp. 189-92.

As required by the Guidelines, the Public Staff investigated the 2014 Cost Report and the 2014 Funding Report, as well as the Company's suggestion that nuclear decommissioning expense be reduced to $0 through a decrement rider. Tr. Vol. 22, p. 193. Its investigation was thorough, and the report that it prepared pursuant to the Guidelines was likewise thorough and well thought-out. Id. at 194. In that report (Public Staff Report; DEC – Maness Cross-Examination Ex. 2), the Public Staff noted that the NDTF fund balance would exceed estimated decommissioning costs at license termination[2] on a North Carolina retail jurisdictional basis by $2.5 billion. Id. at 11-12. The Report further indicated in its "Conclusions and Recommendations" section that the Public Staff had completed its investigation of the Cost Report and the Funding Report, had reviewed the Company's responses to data requests, and had no disagreement with the Company "regarding the calculation and implementation of the $0 expense/revenue requirements

[1] The Chairman ruled that the Commission would take judicial notice of the filings in the Sub 56 Docket in this proceeding. Tr. Vol. 22, p. 183.

[2] Measurement at license termination is the manner in which the Guidelines require the Funding Report to be filed. See DEC – Maness Cross-Examination Ex. 1, Tab 1, Attachment 1.

or any other aspect of its decommissioning cost and funding activity." Id. at 12. The Public Staff Report then concluded that apart from the implementation of the decrement rider, "the Public Staff has no recommendations for further action by the Commission in this matter." Id. (emphasis added).

In this rate case, the Company again determined that the nuclear decommissioning expense in its cost of service was $0. Tr. Vol. 12, p. 49. The Public Staff, however, asserted, through witness Hinton, that the NDTF was overfunded by $2.35 billion. Tr. Vol. 22, p. 252. The Public Staff proposed that these "excess" funds be returned to customers, and that this could be accomplished by reducing North Carolina retail expense by $29.1 million. Id. at 260.[1]

Under applicable NRC and IRS regulations, these funds could not be simply withdrawn from the NDTF, a fact recognized by Public Staff. Id. at 252. It indicated instead, through witness Maness, that if the Company "cannot remove such funds from the NDTF, its shareholders will be required to provide (i.e., loan) the funds for the expense reduction …." Id. at 105 (emphasis added). Witness Maness added that this loan would be "on a temporary basis." Id. Company witness Doss testified, "if the Public Staff's recommended rate-making mechanism is approved, and if actual experience mirrors the projections on which the Public Staff's recommended refunds are based, the Company would not be entitled to collect on the loans to ratepayers until funds could be withdrawn from the NDTF upon the completion of nuclear decommissioning activities, which is currently expected to occur in approximately 50 years." Tr. Vol. 12, p. 60.

Discussion and Conclusions

The key factual predicate to the Public Staff's recommendation is that the NDTF is overfunded. The facts in this case indicate that it is premature to reach such a conclusion. The Public Staff's principal proponent of the notion that the NDTF is overfunded – witness Hinton – did not testify that this is the case in absolute terms. Rather, his testimony is hedged with qualifiers: "Assuming the projected decommissioning costs and earning returns … are accurate through when DEC's last nuclear unit is decommissioned, the NDTF is currently over-funded by $2.35 billion." Tr. Vol. 22, p. 252 (emphasis added). A number of qualifiers and the uncertainty regarding future events underlie witness Hinton's conclusion that the NDTF is currently overfunded. Id. However, witness De May testified that on an NC retail basis, the NDTF is actually underfunded as of the end of the test year:

> [T]he NDTF balance was $2.19 billion as of December 31, 2016. The estimated decommissioning cost (in 2016 dollars) as of December 31, 2016 was $2.46 billion. In other words, on a current dollars basis, the NDTF was approximately 89% funded as of December 31, 2016.

Tr. Vol. 4, pp. 79-80.

[1] Witness Hinton's direct testimony indicated that this figure was $19.4 million (Tr. Vol. 22, p. 252), but he discovered an error in his analysis and corrected the figure to $29.1 million Id. at 260.

Witness De May further testified that the Company uses three methods to determine whether the funding levels in the NDTF are adequate such that the nuclear decommissioning portion of cost of service should be assigned a zero-dollar cost. One is the "current value" method, which is what is described above. Another is the "projected value" method, which is the basis of witness Hinton's conclusion. The projected value method measures, as its name suggests, the funds in the NDTF projected as of the end of decommissioning, still decades into the future, compared to projected costs, again decades into the future. In other words, the projected value method measures "the projected balance of the NDTF at the end of the decommissioning period, i.e., after all decommissioning activities are completed, and is in future dollars (ranging from 2058 through 2067)." Id. (emphasis added). Witness De May testified that this measure indicates whether the NDTF is adequately funded, but does not indicate that it is fully funded – for that, one cannot know "until the last dollar is spent on decommissioning." Id. at 568.

The third method witness De May described is the "probability of success" method. This method, witness De May explained, uses a probability of success ratio to evaluate the likelihood of having sufficient funds to fully decommission each nuclear unit. Id. at 80. This approach involves 5,000 Monte Carlo simulations of market returns and escalation factors between the time of analysis and the end of decommissioning and generates a percentage of scenarios for which funding is adequate to meet all future decommissioning obligations. Id. Witness De May testified that "[a]s of December 31, 2016, the nuclear unit probability of success ratios ranged from 77% to 85%, depending on the unit; conversely, the probability of not having sufficient funds to decommission the nuclear units ranged from 15% to 23%." Id. (emphasis in original). Although these percentages may support a determination that no additional funding from ratepayers is currently required to fund the NDTF, the Company submits that in no way should this be interpreted as supporting a view that the NDTF is "overfunded."

The Company based its determination that the NDTF funding levels were adequate and that, as a consequence, it would not request any nuclear decommissioning cost in its revenue requirements in this case, on the fact that the NDTF has experienced higher than expected returns recently and that the escalation rate assumption has remained modest. Id. at 82. There is, of course, no assurance that these conditions will extend into the future, and certainly no assurance that they will extend decades into the future. Uncertainty is further compounded by timing, as license extensions or unforeseen circumstances could accelerate or push out the plants' retirement dates. Insofar as escalation rates are concerned, witness De May testified that the model used to estimate funding requirements is highly sensitive to changes in the escalation rate assumption, and that an "increase in the forecasted escalation rate from 2.40% to 3.09%, a 0.69% increase, fully eliminates the projected NDTF overfunded balance at the end of the decommissioning period." Id. He noted that for the period 1913-2017, the average consumer price index (CPI-U) rate has been 3.24%. Accordingly, changing the escalation rate from the currently model rate of 2.4% just to the average CPI-U increase over the past hundred years means that the Public Staff's projected $2.35 billion overfunding disappears. Id. at 587.

He also testified regarding returns, "You probably hear this all the time in investment jargon, past returns are not an indication of future results." Tr. Vol. 5, p. 58. A 2015 Public Staff Report (DEC – Maness Cross-Examination Ex. 2), noted:

> The current healthy financial position of the ... [NDTF] relative to estimated costs results largely from significantly higher than expected trust fund investment returns that have been experienced in recent years. The trust fund has not, however, always experienced such strong investment returns, and in fact, there have been many years of low or negative investment returns.

Id. at 13.[1]

Witness Hinton attempts to address concerns that the Public Staff's recommendation would lead to future underfunding by asserting that there are sufficient regulatory protections to avoid any significant under recovery in the NDTF. Tr. Vol. 22, p. 252. However, DEC contends that this statement ignores that some of those protections include restrictions preventing withdrawals from the NDTF. As witness De May indicated,

> [T]here is a reason it's illegal to take money out of the trust. It's because ... [the NDTF is] not an investment account, it's not a savings account. It's there for the very good public policy of decommissioning nuclear power plants ....

Tr. Vol. 4, p. 588.

In light of all of the evidence presented, the Commission determines that it is premature to find and conclude that the NDTF is overfunded. While the funding model that is used to determine the annual nuclear decommissioning expense forecasts that under various assumptions, the NDTF may be overfunded by approximately $2.4 billion, the evidence also indicates that on a current dollar basis it is only 89% funded. The Commission agrees with witness De May's concern that returning the projected excess funds to ratepayers now could lead to underfunding of the NDTF in the future. The record shows that the NDTF has experienced higher than expected returns recently, and the escalation rate used to forecast decommissioning costs has remained modest compared to historical rates of inflation, both of which have contributed to favorable results. Changes in assumptions for variables, including investment returns, escalation rates and decommissioning start or completion dates, will all impact future NDTF funding levels, as will deviation of future experience from current forecasts. In the judgment of the Commission, while the NDTF is currently adequately funded, it is premature to find and conclude that the NDTF is overfunded, and therefore, it would not be prudent to return funds to customers at this time, and perhaps for several years, even if it were legally permissible to do so.

Given the Commission's finding and conclusion in this regard, it is not necessary for the Commission to address the related issues between the parties regarding GAAP treatment, retroactive ratemaking and prior agreements.

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[1] For example, industry-wide from 2006 through 2008, the financial markets had a significant negative impact on trust fund balances. See NRC Office of Nuclear Regulation, 2009 Summary of Decommissioning Funding Status Reports for Nuclear Power Reactors (SECY-09-0146, October 6, 2009), p. 7, available online at: https://www.nrc.gov/docs/ML0925/ML092580041.pdf. The Commission takes judicial notice of this NRC report.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 52-55

The evidence supporting these findings and conclusions is contained in the Company's verified Application and Form E-1, the testimony and exhibits of DEC witnesses Spanos, Doss, and Kopp, Public Staff witness McCullar, and the entire record in this proceeding.

Company witness Doss introduced Doss Exhibit 3, the revised depreciation study filed in this docket (Depreciation Study), as prepared by Gannett Fleming Valuation and Rate Consultants, LLC. Tr. Vol. 12, p. 56. As explained by witness Doss, the Depreciation Study included updates to estimates of final plant depreciation costs for steam, hydraulic, and other production plants, as well as updated forecasted generation plant retirement dates. Id. at 77. In addition, witness Doss introduced Doss Exhibit 4, the Decommissioning Cost Estimate Study (Decommissioning Study) prepared by Burns and McDonnell Engineering Company, Inc. (Burns & McDonnell), an external engineering firm. This report included estimates for final decommissioning costs at steam, hydraulic, and other production plants.

DEC witness Doss testified that the updated depreciation rates for various fossil and hydro plants reflect changes in the probable retirement dates to align with current licenses, industry standards, or operational plans due to aging technology, assumptions for future environmental regulations, or new planned generation. Tr. Vol. 12, pp. 51-52. In addition, the Depreciation Study incorporates generation assets that have been placed in service since the last study, as well as the W.S. Lee Combined Cycle Plant, once it goes into service. Id. at 52. Additionally, the rate for meters to be replaced under the Company's Advanced Metering Infrastructure (AMI) deployment was updated to allow recovery of the net book value over three years. Id. The Depreciation Study uses a 15-year average service life for the new AMI meters being deployed, increasing depreciation expense. Id. Finally, witness Doss also notes that there is a net decrease in the depreciation expense for distribution, transmission, and general plant assets, primarily driven by longer average service lives for assets such as overhead and underground conductors and services. Id.

Public Staff witness McCullar and CIGFUR III witness Phillips also made recommendations related to depreciation expense. Witness McCullar recommended several adjustments to the Company's proposed depreciation rates including adjustments to future terminal net salvage costs (also known as decommissioning and dismantlement costs), to other production plant interim net salvage percentages, and to remove inflation from terminal net salvage costs. Tr. Vol. 26, pp. 777-78, 783-85. Witness McCullar testified that based on December 31, 2016 investments, DEC was proposing an increase in its depreciation annual accrual of $81,480,296. Tr. Vol. 26 p. 773. Based on Public Staff witness McCullar's investigation, the Public Staff recommended an increase in DEC's depreciation annual accrual of $20,709,566 based on December 31, 2016, investments, a decrease of $60,770,730 from the amount proposed by the Company. Tr. Vol. 26, p. 775. The difference between the Company's and the Public Staff's proposed depreciation annual accrual results from four adjustments proposed by witness McCullar, and one recommended by Public Staff witness Maness, as discussed below. Finally, witness Phillips recommended that changes in the depreciation rates should net to a zero-dollar impact.

Estimated Terminal Net Salvage Costs – Contingency

Burns & McDonnell conducted the Decommissioning Study for DEC, which formed the basis for DEC's terminal net salvage cost estimates. In that study, a 20% contingency for future "unknowns" was included in DEC's estimate of future terminal net salvage costs. "Public Staff witness McCullar recommended that the 20% contingency for future "unknowns" included in DEC's estimate of future terminal net salvage costs be eliminated. Tr. Vol. 26, p 778. Witness McCullar explained that including a 20% contingency factor puts the risk of possible future unknowns on current ratepayers. Id. Witness McCullar pointed out that DEC has not identified actual future costs to be covered by the contingency, but estimates future terminal net salvage costs based on anticipated contractors' bids for dismantlement of equipment, addressing of environmental issues, and restoration of the site, and then adds 20% for unknown costs that DEC cannot specifically identify. Tr. Vol. 26, pp. 778-79. Public Staff witness McCullar testified that putting all the risk of "estimated future unknown unidentified costs" on current ratepayers was inappropriate and recommended a contingency of 0%. Tr. Vol. 26, p. 780. In response to witness McCullar's recommendation, DEC witness Kopp explained why a 20% contingency is appropriately included in DEC's Decommissioning Study. He explained that contingency protects customers by ensuring more accurate estimates of the costs of terminal net salvage to be incurred in the future. Tr. Vol. 10, p. 108. He stated that while these costs could not be specifically identified, it was reasonable to expect them to be incurred. Id. Witness Kopp explained that direct decommissioning costs were estimated based on performing known tasks under ideal conditions. Tr. Vol. 10, p. 109. However, Company witness Kopp admitted that Burns & McDonnell did not obtain any firm quotes for DEC facilities, but used unit pricing or its experience. Tr. Vol. 10, p. 137. Further, according to witness Kopp, the contingency was added to recognize the likelihood of cost increases for unknown costs. Id. He pointed out uncertainties in work conditions, scope of work, the manner in which work would be performed, estimating quantities, weather, and unknown contamination, among other things. Tr. Vol. 10, pp. 109-10. DEC witness Kopp testified that inclusion of contingency costs was standard industry practice. Tr. Vol. 10, p. 110. He explained that a 20% contingency was appropriate at a site where power had been generated for years and where there was likely to be more environmental contamination, and thus was based on the level of risk of additional contamination. Tr. Vol. 10, pp. 111-12. Witness Kopp pointed out that there had been no on-site testing for hazardous materials or environmental contamination, no sampling of groundwater, no subsurface investigation, no asbestos inventories, and that the cost estimates included only a minimal level of environmental remediation. Tr. Vol. 10, pp. 111-12. Company witness Kopp contended that it would not be prudent to try to develop estimates that were more accurate or precise so that a smaller contingency would be reasonable, because of the high cost of conducting such a study and the limited time that the cost estimates could be considered reliable. Tr. Vol. 10, p. 113. Yet he argued that while these estimates were not precise enough to develop a more reasonable contingency, they were precise enough on which to base depreciation rates. Tr. Vol. 10, pp. 113-14. DEC witness Kopp noted that Burns and McDonnell had performed a decommissioning study for DEP in 2012, and that study's estimates for the decommissioning and demolition of Cape Fear, H.F. Lee, Sutton, Robinson, and Weatherspoon plants forecast costs 11% lower than actually incurred. Tr. Vol. 10, p. 114.

Accordingly, witness Kopp explained that a 20% contingency on these costs is both reasonable and warranted based on the risk level associated with the decommissioning projects.

As the Company pointed out in its Response to Public Staff Data Request No. 17, the anticipated contractor's bid is based on performing known dismantlement tasks under ideal conditions. Id. at 116. (emphasis added) Witness Kopp contended that Public Staff witness McCullar had not taken into account that the direct costs were based on known tasks occurring under ideal conditions. Tr. Vol. 10, pp. 115-16. Witness Kopp also pointed out the minimal level of investigation Burns & McDonnell made into the existence and costs of potential environmental contamination and remediation, which he argued supported a 20% contingency. Tr. Vol. 10, p. 116. Regarding witness McCullar's contention that the Company should not recover a contingency for costs that cannot be identified at this time, witness Kopp agreed that specific future costs could not be identified, but noted that some typical costs that might be incurred or that have been incurred on similar projects were known. Tr. Vol. 10, pp. 117-18.

On cross examination, Company witness Kopp indicated that the Decommissioning Study did not take into account the impact of any planned changes to convert the Belews Creek, James E. Rogers (Cliffside), and Marshall plants to dual fuel capability as planned by the Company (Spanos/Kopp Cross Exhibit 1), which could increase or decrease the study's estimates. Tr. Vol. 10, pp. 127-29. Neither did the study take into account any changes in steel and aluminum prices that might occur due to imposition of tariffs. Tr. Vol. 10 pp. 133-34. Witness Kopp also stated that decommissioning and demolition was the most prudent option at the end of a plant's useful life, but acknowledged sale of a plant as another option. See Duke Energy's announcement of the sale of its retired Walter C. Beckjord coal-fired power plant, Spanos/Kopp Public Staff Cross Exhibit 3. Tr. Vol. 10, pp. 131-33.

In his testimony, DEC witness Kopp testified that, "[a]s engineering design for demolition progresses and some of these unknowns can be determined through subsurface investigations, asbestos sampling, and engineering specifications, the amount of contingency may be reduced; however, contingency would never be completely eliminated." Tr. Vol. 10, pp. 112-13. He also stated that the "Company performed no subsurface investigations, asbestos inventories, or groundwater sampling to identify and define remediation requirements during this planning phase." Tr. Vol. 10, p. 112. However, on cross-examination, witness Kopp admitted that the Company did perform asbestos inventories. Tr. Vol. 10, p. 136. But instead of relying on studies that had been performed, "Burns and McDonnell did not rely upon these historical studies ...." Tr. Vol. 10, p. 136.

DEC witness Kopp highlighted all the environmental testing that has yet to be done and all the uncertainties inherent in the study. While the Decommissioning Study was conducted based on data from 2016 and 2017, DEC has since announced plans to convert three of its plants to dual-fuel capability, changing some of the assumptions in the study. While it is impossible to anticipate all future costs, merely being able to identify possible future costs or costs incurred for other projects is not the most firm basis on which to calculate contingency. This causes some concern for the Commission.

The Commission takes note that the Company failed to take into account the possibility that scrap prices may increase or that the production plant may be repurposed, or sold. Further, DEC witness Kopp's claim that a contingency is needed to account for the unknown of asbestos is not fully supported by the record in this proceeding, since DEC has performed asbestos inventories and identified an asset retirement obligation for these legal asbestos abatement obligations. See Kopp/Spanos Public Staff Exhibit 4. Identifying these costs should reduce the unknown of asbestos and thus reduce any contingency.

Based on the above discussion and all of the evidence in the record, the Commission finds that the contingency proposed for net terminal salvage in this proceeding of 20% is improper and should be reduced. While the Commission appreciates the Public Staff's concern for keeping depreciation rates low, the potential for further environmental costs and remediation costs should not be given short shrift, especially in light of other environmental costs that are discussed elsewhere in this Order. However, the Commission acknowledges the arguments that the Public Staff has made, and in an attempt to strike a fair balance, the Commission finds that a 10% contingency factor is fair to all parties. The Commission further notes that in DEP's most recent rate case proceeding, Docket No. E-2, Sub 1142, the Commission approved a 10% contingency factor. The Commission is confident that a 10% contingency factor, while less than DEC's requested factor of 20%, should protect the Company from additional costs it will incur but cannot specify at the present date. The Commission also finds that a 10% contingency factor properly reflects the inclusion of items that should push unknown costs downward (i.e increase in scrap prices, etc.) thereby protecting the ratepayers as well. Based on the foregoing, the Commission concludes that including a contingency factor of 10% should be utilized by the Company.

Cost Escalated to the Date of Retirement

It is important to recover the service value of the Company's assets by determining the net salvage costs that will be incurred in the future. As DEC witness Spanos explained, using the straight-line method of depreciation, these costs are recovered ratably, or in equal amounts, each year over the life of the Company's plant. Tr. Vol. 10, p. 83. This approach is consistent with the Uniform System of Accounts, which specifies that the cost of removal is the actual amount paid at the time the transaction takes place. Id. at 84. As such, including the future cost of net salvage for plant accounts is consistent with established depreciation concepts. In developing decommissioning cost estimates, it is necessary to escalate those estimates to the time period in which the cost is expected to be incurred.

Public Staff witness McCullar testified that the Company took the estimated future terminal net salvage costs from the Decommissioning Study, which are in year 2016 dollars, and inflated them to the year of the assumed retirement of the production plant. She testified that DEC proposes to collect these inflated amounts in today's more valuable dollars from ratepayers. Tr. Vol. 26, pp. 780-81. Witness McCullar's Exhibit RMM-2 showed how for the Cliffside plant, the estimated terminal net salvage cost of $48,075,000 in year-2016 dollars was inflated to $105,945,645 in year-2048 dollars, assuming an annual inflation rate of 2.5% to 2048, the estimated year of retirement, increasing the estimated net salvage cost by a factor of 2.2. Tr. Vol. 26, p. 781. DEC proposes to begin collecting this $105,945,615 calculated using year-2048 dollars from current ratepayers, who would be paying in current dollars. Id. Public Staff McCullar contended that it would be unreasonable in this case to collect these inflated costs of removal in current dollars because it imposes too much risk on ratepayers due to the significant period of time over which the inflation is estimated. Tr. Vol. 26, p. 282.

Witness McCullar recommended that DEC should inflate the terminal net salvage costs to the year 2023, or the retirement date, whichever occurs first. Witness McCullar testified that she selected 2023 because it aligned with the time when the Company is expected to file its next rate case. Witness McCullar stated, "since depreciation rates approved in this proceeding are expected to go into effect in 2018, the year 2023 would be five years later, by which time depreciation rates would have been reviewed in a new base rate case." Tr. Vol. 26, p. 784. Witness McCullar noted that her recommendation reduces the risk on ratepayers associated with paying rates based on extended periods of estimated inflation, while protecting the Company from the risk that it would not be able to collect its net salvage costs. Tr. Vol. 26, p. 784.

Witness Spanos explained that many of the Company's plants will not be retired for many years. Tr. Vol. 10, p. 86. Witness Spanos highlighted the importance of "understanding the Company's expectations for these assets, as well as the estimates within the industry." Id. at 91. Accordingly, the net salvage costs must be escalated so that the correct amounts are allocated over the remaining lives of the plants. Tr. Vol. 10, p. 86. The approach used by the Company to escalate cost is widely supported by authoritative depreciation texts and industry practice. For example, witness Spanos pointed out that the NARUC Manual provides the following:

> Under presently accepted concepts, the amount of depreciation to be accrued over the life of an asset is its original cost less net salvage. Net salvage is the difference between gross salvage that will be realized when the asset is disposed of and the costs of retiring it.

Tr. Vol. 10, p. 88. (emphasis added).

In addition, Wolf and Fitch, another highly regarded authoritative depreciation text, provides further support for the position that inflation is appropriately a part of the future cost of net salvage. Wolf and Fitch also argue against a present value or current value concept. In his testimony, Witness Spanos provided the following passage from Wolf and Fitch:

> Some say that although the current consumers should pay for future costs, the future value of the payments, calculated at some reasonable interest rate, should equal the retirement cost. Studies show that the salvage is often "more negative" than forecasters had predicted.

Tr. Vol. 10, p. 89.

Finally, witness Spanos referenced Accounting for Public Utilities by Robert L. Hahne and Gregory E. Aliff to support the proposition that the Uniform System of Accounts and regulatory definition require net salvage to be estimated at a future price level. Id.

The testimony and evidence presented in this case demonstrates that authoritative texts and sound depreciation practices support escalating terminal net salvage costs to the date that the costs are expected to be incurred. Despite arguing against an approach in which the Company would recover costs over the life of the asset, witness McCullar concedes that some escalation is necessary. In fact, witness McCullar escalated terminal net salvage to the projected date for the Company's next base rate case in her calculations. Further, witness McCullar's escalation rate is entirely dependent on the timing of when the Company files its base rate case and lacks any nexus to the timing of the future retirement of the asset. The Commission notes that the record is void of any accounting literature support for witness McCullar's approach, nor would such an approach be appropriate.

The Commission cannot rely upon the scheduling of rate cases to remedy the flaws in witness McCullar's alternative proposal. Witness McCullar's approach is not supported by sound depreciation methods and would likely result in the under recovery of net salvage costs over the life of the asset. To that end, other state utility commissions have rejected witness McCullar's alternative approach as unsupported. For example, in a recent case before the Washington Utilities and Transportation Commission (WTC), witness McCullar advanced similar arguments against the escalation of terminal net salvage costs along with other recommendation related to depreciation.[1] In rejecting the recommendation, the WTC noted that Public Counsel and witness McCullar provided no response to the critique that witness McCullar's approaches were not supported by authoritative accounting literature.[2] The WTC found witness McCullar's net salvage proposal "[v]ague in its methodology, not supported by authoritative accounting literature, and supported by unwarranted assumptions."[3]

The fact is the vast majority of jurisdictions use a method for net salvage in which future net salvage is estimated at its future cost and recovered through straight-line depreciation (also known as the traditional method). Approximately 46 out of 50 jurisdictions recover future costs using the straight-line depreciation method. The use of this method is also consistent with the treatment of escalation in the most recent DEP rate case. As witness Spanos explained, depreciation should be done in a systematic and rational manner based on information known at the time and consistent with the Uniform System of Accounts. Id. at 165.

Considering all the evidence, the Commission finds and concludes that the escalation of terminal net salvage cost and the use of the straight-line method of depreciation in determining escalation as performed in the DEC Decommissioning Study is just and reasonable, appropriate for use in this case, and is adopted.

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1 See Washington Utilities and Transportation Commission v. Puget Sound Energy, Final Order Rejecting Tariff Sheet; Approving and Adopting Settlement Stipulation; Resolving Contested Issues, & Authorizing and Requiring Compliance Filing, Washington Utilities & Transportation Commission, Docket UE-170033 (December 5, 2017) Puget Sound Order.

2 Puget Sound Order, pp. 50-51.

3 Id. at 60. The WTC noted further that witness McCullar's "comparison of net salvage accruals to net salvage expenditures PSE incurred during recent years would effectively recover net salvage as an operating expense, not a depreciation expense."

Other Production Plant Interim Net Salvage Percent Production Accounts

In this case, DEC witness Spanos testified that he recommended a future net salvage percent of negative 4% for other production accounts. Id. at 90. The estimated future net salvage is part of the annual depreciation accrual, which is credited to the reserve to cover the estimated future net salvage costs. As witness Spanos explained, he established an interim net salvage percent on an account basis and then performed the appropriate calculation in order to get the appropriate weighted interim net salvage, excluding account 343.1. Tr. Vol. 12, p. 143. The net salvage estimates were based on an analysis of historical cost of removal and salvage data, expectations with respect to future removal requirements, and markets for retired equipment and materials. See Doss Exhibit 3 IV-2; Tr. Vol. 12, p. 116. The interim net salvage component is approximately 32% of the utilized net salvage percent for other production plant. Id. at 90. Witness Spanos further testified that he noted that the Public Staff's recommended interim net salvage percentage had been included in the depreciation rate proposed for the Lee Combined Cycle Plant. Id. DEC witness Spanos contended that determining an interim net salvage percentage for other production plant should be based on historical data as well as informed judgment. Id. He stated that Accounts 343 and 344 included large amounts of gross salvage related to older combined cycle facilities not applicable to all assets in the account. Id. Company witness Spanos also stated that the high gross salvage numbers were related to the rotable parts of combined cycle facilities, consistent with DEP. Id.

Public Staff witness McCullar proposed a 0% net salvage value for accounts 342, 343, 344, 345, and 346. She testified that for some accounts, the annual accrual amount that would be accrued for estimated net salvage is several times the annual amount DEC actually incurs for net salvage. Tr. Vol. 26, p. 278. Witness McCullar indicated that the historical analysis has been a positive $12,891,310 per year for the last three years and a positive $8,649,160 per year for the last five years. Witness McCullar explained that these positive net salvage amounts indicated that DEC's booked gross salvage exceeded the Company's incurred costs of removal and thus, DEC did not need to collect interim removal costs for these accounts. As a result, witness McCullar took the position that DEC should utilized a 0% interim net salvage based on DEC's actual experience. Witness McCullar further testified that the 0% interim net salvage would not include the final decommissioning costs. The impact of the Public Staff's proposed adjustments to terminal net salvage contingency and escalation rates and interim net salvage results in a decrease in DEC's proposed depreciation rates as of December 31, 2016, of $13,382,159, as shown on p 14 of Exhibit RMM-1 on the line for Total Production. Tr. Vol. 26, p. 786.

In response, witness Spanos testified that in the case of other production plant, it is critical to understand all the components of the historical data. For example, in Accounts 343 and 344, there are large amounts of gross salvage and corresponding retirements that relate to the early installations of combined cycle facilities which are not applicable to all assets in the account. Tr. Vol. 10, p. 91. As witness Spanos described further, the high gross salvage amounts relate to the rotable parts of the combined cycle facilities, which are handled consistently with DEP's assets. Id. Under cross-examination by Public Staff, witness Spanos explained that Account 343 contains high salvage amounts in years 2014, 2015, and 2016, but using informed judgment, he understood those amounts to be related primarily to rotable parts and associated with combined cycle facilities. Using more than just statistical analysis is necessary to evaluate these production plants; informed judgment must also be relied upon as Witness Spanos did. In recommending the negative 4% interim net salvage percentage, witness Spanos took into account the Company's expectations for the assets as well as the estimates within the industry. Id.

The Public Staff presented evidence on cross-examination of DEC witnesses Kopp/Spanos regarding the Company's proposed positive net salvage percentages in Accounts 343 and 344 were related to rotable parts. Kopp/Spanos Public Staff Cross-Examination Exhibit 7 shows that DEC has established rotable parts in a separate account, Account 343.1. Further, Kopp/Spanos Public Staff Cross Exhibit 8 shows that the Public Staff did not propose any adjustment to the interim net salvage percentage for Account 343.1, Prime Movers Rotable. Additionally, under cross examination, witness Spanos admitted that Account 343.1, containing these rotable parts, was also excluded from the Company's interim net salvage proposal for Accounts 342, 343, 344, 345, and 346. Tr. Vol. 10, p. 143.

Based on the evidence discussed above and the entire record in this case, the Commission finds that the Public Staff's proposal to set an interim net salvage percentage of 0 for Accounts 342, 343, 344, 345, and 346 is reasonable. Historical data show that using a negative value, as was previously set, has resulted in DEC overcollecting its costs. It would be inequitable to charge customers for costs that the utility is unlikely to incur. As discussed previously, the Company has stated publicly that it plans to file multiple rate cases between 2019 and 2023, and therefore, this issue can be reexamined in the next base rate case.

Other Depreciation Recommendations

CIGFUR III witness Phillips recommended that any approved changes to depreciation rates should net to a zero-dollar impact on the level of depreciation expense included in rates. Tr. Vol. 10, p. 94. He further recommended that customers not be burdened at this time by the impact of shortening service lives of generating plants based upon assumptions about changing and evolving environmental regulations. Id.

As DEC witness Spanos correctly asserted, witness Phillips provided no support or justification for his net zero proposal, other than a desire that depreciation rates not increase. Tr. Vol. 10, p. 94. Witness Phillips offered no credible critique of the Company's filed Depreciation Study and provided no alternative analysis. The Depreciation Study demonstrates that current depreciation rates are insufficient and that adjustments are necessary for DEC to recover the full cost of its assets providing service to DEC's customers. Id. at 95.

Furthermore, witness Phillips incorrectly states that depreciation rates have changed due to changes to life spans as a result of environmental regulation. Witness Spanos highlighted that there are a variety of reasons that depreciation rates change over time as evidenced by the Depreciation Study filed in this case. The Depreciation Study includes all of DEC's assets, and changes in depreciation rates occur for many reasons, including updated service life and net salvage estimates, updated historical data, and additions to generating facilities. The Depreciation Study is based upon the available information regarding the Company's assets, and the depreciation rates, therefore, needs to be updated to reflect current circumstances. Tr. Vol. 10, p. 95.

For the foregoing reasons, CIGFUR III witness Phillips' blanket recommendation regarding depreciation rates lacks any conclusive support and is rejected.

Conclusion

In light of all of the evidence presented, the Commission finds and concludes that the depreciation rates proposed by DEC in this case, which are based on the revised Depreciation Study included as Doss Exhibit 3 and the Decommissioning Study included as Doss Exhibit 4, with the exception of the adjustments discussed above, are just and reasonable, fair to both the Company and its customers, and therefore, are approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 56-58

The evidence in support of these findings of fact and conclusions is contained in the testimony and exhibits of Company witnesses De May, Fountain, and McManeus; Public Staff witnesses Boswell, Parcell, and Hinton; Tech Customers witnesses Strunk and Brown-Hruska, NCLM witness Coughlan; Justice Center et al. witness Howat; Kroger witness Higgins; CIGFUR III witness Phillips and the entire record in this proceeding.

The federal Tax Cuts and Jobs Act (the Tax Act) was signed into law on December 22, 2017. Among other provisions, the Tax Act reduced the federal corporate income tax rate from 35% to 21%, effective January 1, 2018.[1] It also repealed the manufacturing tax deduction and eliminated bonus depreciation. The Company filed its application for rate increase on August 25, 2017, many months before the enactment of the Tax Act and, therefore, the revenue requirement the Company requested was based on the pre-Tax Act tax laws.

On January 16, 2018, DEC witness McManeus filed her Second Supplemental Direct Testimony that only included limited discrete changes as a result of the Tax Act relating to the elimination of bonus depreciation and the manufacturing tax deduction. Her filing did not include an adjustment to income tax expense as a result of the decrease in the federal corporate income tax rate, nor did it include any proposal for the return of the protected and unprotected Federal EDIT to ratepayers.

In her direct testimony filed on January 23, 2018, Public Staff witness Boswell included an adjustment to income tax expense to reflect the decrease in the federal corporate income tax rate, as well as to remove the manufacturing tax deduction that was also included in the Tax Act. She stated that at that time, the Public Staff was waiting for information from the Company regarding Federal EDIT and reserved the right to supplement her filing to include the Public Staff's proposal for flow back of Federal EDIT.

[1] In response to the enactment of the Tax Act, on January 3, 2018, the Commission opened a rulemaking docket (Docket No. M-100, Sub 148, i.e. the Tax Docket) for the purpose of determining how the Commission should proceed. In the Order establishing the Tax Docket, the Commission placed all public utilities on notice that the federal corporate income tax expense component of all existing rates and charges, effective January 1, 2018, would be billed and collected on a provisional rate basis.

In rebuttal testimony filed on February 6, 2018, DEC proposed an immediate reduction in the Company's revenue requirement, within the context of this proceeding, to account for the reduction in the federal corporate income tax rate but offered no proposal to return Federal EDIT to ratepayers. Company witness Fountain testified that the passage of the Tax Act "provides the Commission with a unique tool to smooth out customer rate adjustments during a multi-year transition period." Tr. Vol. 6, p. 212. He stated that this could be accomplished by offsetting items such as storm response costs, ongoing coal ash basin closure compliance costs or other environmental compliance costs, or accelerating the depreciation of certain assets, such as the existing AMR meters or coal plants. Tr. Vol. 6, p. 213.

In her rebuttal testimony, witness McManeus testified that the Company opposed witness Boswell's adjustment to reduce income tax expense. Tr. Vol. 6, p 323. Witness McManeus testified that the Company had identified the amount of reduction in annual revenue requirement related to reduced income tax expense and translated the amount into a decrement rate per kWh. Witness McManeus stated that the Company proposed to apply the decrement to North Carolina retail service beginning January 1, 2018, and defer the resulting amount into a regulatory liability, continuing the deferral until new rates are established in this rate case that reflect the benefits of the lower tax expense. Tr. Vol. 6, p. 331.

In supplemental testimony filed on February 20, 2018, witness Boswell presented the Public Staff's proposal regarding the flowback of Federal EDIT. Witness Boswell included three adjustments based on the information provided by the Company. First, she recommended the return of protected Federal EDIT based upon the Company's calculation of the net remaining life of the timing differences, as required under the Internal Revenue Code. For the unprotected Federal EDIT, witness Boswell recommended removing the Federal EDIT regulatory liability associated with the unprotected differences from rate base, and placing it in a rider to be refunded to ratepayers over two years on a levelized basis, with carrying costs. Witness Boswell stated that immediate removal of unprotected Federal EDIT from rate base increases the Company's rate base and mitigates regulatory lag that might occur from refunds of unprotected Federal EDIT not contemporaneously reflected in rate base. Further, she maintained that refunding the unprotected Federal EDIT over two years allows the Company to properly plan for any future credit needs. Tr. Vol. 26, pp. 618-19. Ultimately, during the hearing, the Public Staff modified its proposal to adjust the flowback period from two years to five years. Boswell Second Supplemental Testimony, filed March 19, 2018, Tr. Vol. 26, pp. 637-38. The modified proposal is referred to herein as the Public Staff Proposal.

In response to the Public Staff's original 2-year EDIT flowback proposal, the Company Proposal was made initially in Supplemental Comments, filed March 1, 2018, in Docket No. M-100, Sub 148, a docket that the Commission established on January 3, 2018, in order to gather comments from the utilities it regulates along with the Public Staff and other interested parties, to decide how to implement the Tax Act (Tax Docket). By letter filed the next day, the Public Staff objected to the Company Proposal being made in the Tax Docket, in light of the fact that the Company's general rate case was then open and had not yet gone to hearing. Accordingly, the Company then made its proposal in this Docket on the opening day of the expert witness evidentiary hearings, and the Commission took judicial notice of all filings in the Tax Docket. Tr. Vol. 5, p. 14.

ELECTRIC – RATE INCREASE

On the first day of the evidentiary hearing, the Company presented its proposal to address the Tax Act. The Company Proposal was presented in this proceeding by witness De May. Tr. Vol. 4, pp. 423-24; Tr. Vol. 5, pp. 67-79; De May Rebuttal Ex. 5. The Company Proposal has three basic component parts, and the first two components reduce the Company's revenue requirement.

First, the Company Proposal implements an immediate reduction of approximately $211.5 million to the Company's revenue requirement to reflect collection of federal corporate income tax at the 21% rate instead of the 35% rate. Revised McManeus Stipulation Exhibit 1 – Updated for Post-Hearing Issues, Line 29; Revised McManeus Workpapers – Updated for Post-Hearing Issues, Schedule 1-1, Line 1.

Second, the Company Proposal implements Federal EDIT flowback to customers, with the flowback timeframes varying based on the particular Federal EDIT bucket at issue:

- For protected Federal EDIT, the Company Proposal applies the Tax Act-prescribed IRS normalization rules, resulting in a reduction in revenue requirements of approximately $34.4 million annually or per year. Revised McManeus Stipulation Ex. 1 – Updated for Post-Hearing Issues, Line 30; Revised McManeus Workpapers – Updated for Post-Hearing Issues, Schedule 1-1, Line 2.
- For unprotected Federal EDIT related to property, plant and equipment, the Proposal also applies the normalization rules, although, as all of the parties agree, application of those rules is not required by the Internal Revenue Code. The only modification, that results in a faster flowback, is that while the Company's analysis indicates that the average life of the flowback in the absence of the Tax Act would have been 25 years, the Proposal implements that flowback over 20 years. Tr. Vol. 5, pp. 78, 105. DEC maintained that this was done "for the sake of simplicity" (id. at 105.), and results in a reduction in revenue requirements of approximately $36.7 million annually or per year. Revised McManeus Stipulation Ex. 1 – Updated for Post-Hearing Issues, Line 33; Revised McManeus Workpapers – Updated for Post-Hearing Issues, Schedule 1-1, Line 3.
- For unprotected Federal EDIT not related to property, plant and equipment, the Proposal implements flow back through a five-year decrement rider, with the five-year timeframe being used again "for the sake of simplicity." Tr. Vol. 5, p. 105. The reduction in revenue is approximately $39.6 million per year during the five years the rider is in effect. Revised McManeus Workpapers – Updated for Post-Hearing Issues, Schedule 1-1, Line 7. Because these unprotected Federal EDIT are being flowed back to customers through a rider, that includes a return component, base rates must be adjusted correspondingly (as an increase) in the amount of $15.1 million. Revised McManeus Workpapers – Updated for Post-Hearing Issues, Schedule 1-1, Line 5.

Accordingly, the reduction in revenue requirements effected by these two components of the Company Proposal equals $307.1 million annually or per year. Revised McManeus Workpapers – Updated for Post-Hearing Issues, Schedule 1-1, Lines 1-3, 5 and 7.

The third component of the Company Proposal mitigates, but does not eliminate, the negative cash flow impact of these reductions by increasing annual revenue requirements by $200 million. The Company Proposal (De May Rebuttal Ex. 5) did not originally identify specific means through which this could be accomplished, but did provide examples of accelerated regulatory asset amortization, and also suggested the alternative of collecting certain expenses (for example, the coal ash basin closure cost "run rate") on an accelerated basis.[1] As witness De May testified, in concept this component of the Company Proposal aims "to preserve the cash flow and credit quality, and we can skin that cat a few ways." Tr. Vol. 5, p. 87.

Combined, therefore, the three component parts of the Company Proposal net to a reduction in the Company's annual revenue requirement of almost $107 million. Revised McManeus Workpapers – Updated for Post-Hearing Issues, Schedule 1-1. The Company Proposal implements an immediate reduction in rates to reflect the 21% Federal corporate income tax rate, but also, as witness De May testified, mitigates the impacts and "preserve[s] ... [the Company's] credit quality ... to something that resembles pre-tax reform." Tr. Vol. 5, p. 82.

On cross-examination, Company witnesses Fountain and McManeus were questioned about the Company's income tax proposal. Witness McManeus acknowledged that ratepayers advanced the funds that constitute the Federal EDIT at issue. Tr. Vol. 6, p. 399. She also conceded that tax normalization laws do not dictate when unprotected PP&E Federal EDIT should be returned to ratepayers (unlike protected Federal EDIT). Tr. Vol. 6, p. 399. Witness McManeus further admitted that because unprotected Federal EDIT is not subject to tax normalization rules, the Commission has discretion as to the time period over which the funds will be returned to ratepayers. Tr. Vol. 8, p. 224. She agreed that due to the reduction in the tax rate, the Federal EDIT is no longer needed to cover the Company's taxes. Tr. Vol. 8, p. 224. Witness McManeus acknowledged that the $200 million in accelerated expenses would be included in the Company's revenue requirement. Tr. Vol. 8, p. 226. When asked to identify the specific assets and other items that the Company would include in the proposed $200 million acceleration, she could not identify anything specific, referring to the general options set forth in the proposal. Tr. Vol. 8, p. 230. Witness Fountain conceded that he could understand the positon of some customers who would like to have the benefits of the federal tax reform all flowed back immediately, but testified that the Company's proposal is balanced. Tr. Vol. 7, p. 94.

In response to Commission questions about the Company's income tax proposal, witness McManeus testified that the $200 million figure was provided by witness De May as an appropriate number to accomplish the objectives that he had in mind. The Company did not provide any specific numbers that comprise the $200 million. Tr. Vol. 9, p. 38. Witness Fountain could not identify any specific regulatory assets the Commission could select for accelerated amortization. Tr. Vol. 9, p. 90. Witness Fountain acknowledged that the Company is merely trying to achieve a particular financial metric for its cash flow. Tr. Vol. 9, p. 90.

On March 19, 2018, Public Staff witness Boswell filed her Second Supplemental Testimony. In addition to explaining the current differences between the Company's and the Public Staff's revenue requirement proposals and to refine the outside services adjustment, she addressed DEC's income tax proposal. She explained that while the Company has incorporated the known and measurable reduction in income tax expense associated with the decrease in the federal

[1] Kathy Sparrow, one of the public witnesses in the public witness hearing held in Charlotte on January 30, 2018, also suggested that tax reform gains and coal ash costs could offset against each other. Tr. Vol. 3, p. 95.

corporate income tax rate, the Company appears to have made the refunding of known and measurable tax dollars owed to ratepayers contingent upon increasing annual expenses by $200 million per year for an unknown number of years through the acceleration of depreciation for as yet unknown assets or through accelerating the amortization of costs associated with coal ash basin closures. Tr. Vol. 26, p. 634. She also noted that the Company has calculated the known and measurable refund of protected Federal EDIT based upon tax normalization rules. However, regarding unprotected Federal EDIT, she stated that the Company has proposed an amortization of approximately 82% of its unprotected Federal EDIT over 20 years, with the remaining 18% amortized over five years.

Thus, the Company's and the Public Staff's proposals differ as to: (1) the rate at which unprotected Federal EDIT should be flowed back to ratepayers; and (2) whether it is appropriate to increase the Company's revenue requirement by $200 million to accelerate depreciation of unknown and unspecified assets or legacy meters, or accelerated amortization of coal ash costs. Tr. Vol. 26, pp. 634-35. Witness Boswell noted that the Company does not dispute that the Commission has the discretion to flow back all of the unprotected Federal EDIT over any time period it finds appropriate. Tr. Vol. 26, p. 636. Company witness De May testified extensively regarding the impact implementation of the Tax Act could have on the Company's credit quality and the importance of maintaining the Company's current, high credit rating. Witness De May explained that as a result of the Tax Act, Duke Energy Corporation, the parent Company of DEC, was placed by Moody's on negative credit outlook. Tr. Vol. 4, p. 541. He explained that a negative outlook is different from a ratings downgrade. Witness De May stated that it is "like a yellow light, a warning" (id.), signaling to the investment community that a ratings downgrade could materialize in the next 12 to 18 months. Id. The January 2018 Moody's Report states that the Tax Act is "credit negative" for the utilities sector because of its impact upon cash flow, and that among the companies most negatively impacted is Duke Energy Corporation, the parent company of DEC. January 2018 Moody's Report, pp. 1, 3. The Report specifically notes that the parent corporation's "consolidated cash flow credit metrics are currently weakly positioned and likely to be incrementally pressured by tax reform." Id. at 5.

While Moody's has not put DEC on negative credit outlook, as witness De May explained, "the risk to Duke Carolinas is not zero just because it was not named in the initial report." Tr. Vol. 4, p. 542. Witness De May testified that while DEC currently maintains "a very strong balance sheet," the Tax Act is biased toward the health of corporations, and because utilities are structured different than most corporations, the Tax Act impacts utilities negatively. Tr. Vol. 5, p. 82. As Moody's notes, "most utilities will attempt to manage any negative financial implications of tax reform through regulatory channels ... [and that] actions taken by utilities will be incorporated into our credit analysis on a prospective basis." Moody's January 2018 Report, p. 3.

Moreover, witness De May elaborated, during cross-examination by counsel for CIGFUR III, on the negative impact of weakening the Company's balance sheet: "Duke Energy Carolinas' customers benefit from a strong utility company ... [and] a weakening of the balance sheet is not in the customer's interest, and it does not support the Company's capital plan ...." Tr. Vol. 4, pp. 436-37. He testified further, "[u]ltimately, adverse cash flow impacts also have an adverse impact upon customer rates – DE Carolinas' customers benefit through lower electricity rates when the Company has lower financing costs, greater access to capital, and more timely cash recovery of its investments." Id. at 88-89.

The Company has proposed a 20-year flowback of unprotected but property-related EDIT. The Public Staff has criticized this aspect of the Company Proposal on several grounds. First, Public Staff witness Boswell asserted that the Company has "artificially" created the class of unprotected property-related EDIT. Tr. Vol. 26, p. 636. Witness De May explained that the 20-year period in the Company Proposal is tied directly to the underlying assets that created the deferred tax balances that became Federal EDIT when the Tax Act dropped the corporate income tax rate to 21%. As witness De May testified:

> I would say that from a theory perspective, those excess deferred taxes actually have a life. When I described to you what happened in a single asset where we collect from customers before we pay the government and then we're paying the government, but not collecting from customers, that is something that is dealt with through normalization. But there's a life to that; there's a life cycle to that, and protected and unprotected property related deferred taxes are no different except for the fact that they come from two places in the Internal Revenue Code and the statute protects one and it doesn't the other.

Tr. Vol. 5, p. 78. Witness De May testified further in response to questions from Commissioner Brown-Bland that he trusted "firmly in the theory behind the flowback of excess deferred taxes over the life of the underlying assets" (id. at 102-03.), that the normalization concept underlying the 20-year flowback proposal was discussed at length in the GAO Report, and that "normalization exists for a reason ...." Id. at 103. Witness De May testified that normalization balances the customer and Company interests; it protects the Company's cash flow and also protects the customer against rate volatility, because the deferred balance acts as an offset to rate base, and, therefore, a reduction in rates. Id. at 104.

Also, as both the GAO Report and witness De May noted, deferred taxes represent an interest-free loan from the government that the Company then used, at no cost to customers, to invest in its business. Tr. Vol. 5, pp. 72-73. Witness De May explained that by making these investments, customers saved capital costs by the Company using an interest-free loan from the government rather than investor-supplied capital. However, witness De May testified that because these funds have been invested there is not a readily available reserve pool from which the cash needed to flow back the EDIT can be drawn and the Company would have to enter into financings to flow back EDIT in two years as originally proposed by the Public Staff. Id. at 79. He explained that it helps avoid volatility in customer rates. Id. at 80. Witness De May stated that, "[i]f we flowback these excess deferred taxes instantly or over a two-year period, you would see a dramatic reduction in customer rates followed by a snapping back of rates" and then a faster growth in rates due to the higher rate base. Id.

The Public Staff also raised generational equity concerns in advocating for a shorter flowback time period. EDIT funds, it indicated, "rightfully belong to the ratepayers and should be returned to them as soon as reasonably possible." Tr. Vol. 26, p. 637. Witness De May responded, "... we have to think about how that balance got created." Tr. Vol. 5, p. 73. Witness De May noted that it was created because of tax deferral, and the funds so generated then were invested in the business. Id. The Company argued that normalization, or the gradual return of EDIT over the life of the capital asset being depreciated, actually fosters generational equity by spreading the depreciation benefit over that time period.

The Company asserted that the Public Staff's proposed 5-year flowback would negatively impact its credit metrics. Tr. Vol. 5, p. 86. DEC maintained that, in fact, Hinton Cross Examination Exhibit 1 indicates that the relevant FFO/Debt ratios for the Public Staff Proposal over the Company's five-year planning horizon would fall below the 25% threshold, which the most recent Moody's report on DEC warned could result in a possible downgrade. See Moody's October 2017 Report, p. 2.

Finally, the Public Staff criticized the Company Proposal on the basis that in the last major overhaul of the Tax Code in 1986, the Company proposed and the Commission accepted a 5-year flowback of unprotected EDIT. See Order Allowing Rates to Become Effective (Stipulated 1987 Order), dated December 4, 1987, filed in Docket Nos. M-100, Sub 113 and E-7, Sub 415.

The Company, however, noted some differences between the 1986 tax law and today's Tax Act. First, DEC asserted that the total amount of the North Carolina retail portion of unprotected Federal EDIT is approximately $953 million, and in 1987, the North Carolina retail portion of unprotected Federal EDIT was approximately $28 million. See Application by Duke Power Company for Authority to Decrease Electric Rates and Charges (Stipulated 1987 Application), dated November 13, 1987, filed in Docket No. E-7, Sub 415. Also, as witness De May testified, the magnitude of the reduction in tax rates was smaller in 1986 – the reduction was from 46% to 34%, a 26% decrease, while today the reduction was from 35% to 21%, a 40% decrease. Tr. Vol. 4, p. 446. Finally, DEC argued that the general business environment was different as well. Witness De May testified that in 1986, the Company experienced 5-6% customer growth and today it is half of a percent. Id. at 448. See De May – Public Staff Cross-Examination Ex. 21, Slide 24. Witness De May also stated that the Company is "experiencing environmental challenges unlike anything we had in 1986." Tr. Vol. 4, p. 448.

According to DEC, another credit supportive measure is the third component of its Proposal, which mitigates the negative cash flow impact of Federal EDIT flowback by increasing revenue requirements by $200 million annually. The Public Staff indicated that it is "adamantly opposed" to this part of the Company Proposal. Tr. Vol. 26, p. 639. The Public Staff argued that adoption of this part of the proposal would "virtually" wipe out the "entire" benefit to customers. Id. The Company, however, has noted that customers will benefit under the Company Proposal by $107 million per year. Revised McManeus Workpapers – Updated for Post-Hearing Issues, Schedule 1-1. This component of the Company Proposal provides for early collection of regulatory assets – that is, from the customer perspective, liabilities otherwise owed to DEC by customers. Tr. Vol. 4, p. 445. Witness De May explained that extinguishing these liabilities has a beneficial effect on the Company's cash flows, but also means that customers will pay less in the future. Id. DEC maintained that accelerated payment also reduces the carrying cost of those regulatory assets, again lowering customer charges. Moreover, the Company noted that the Moody's January 2018 Report forecasted this exact type of regulatory outcome, which Moody's predicts will be credit supportive as utilities work through regulatory channels to manage the negative financial implications of tax reform, stating: "For example, to offset a decline in cash flow, utilities could propose to regulators additional investments that benefit customers or accelerate recovery of regulatory assets." Moody's January 2018 Report, p. 3.

The AGO asserted in its post-hearing brief that as a result of recent reductions in the federal corporate income tax, DEC's costs are much lower going forward and it has accrued a large sum in federal deferred taxes that it no longer needs. The AGO argued that these cost reductions should be flowed through to ratepayers promptly. The AGO recommended that the Commission reject DEC's problematic proposals and approve utility rates that promptly flow through the benefits for customers. The AGO stated that it concurs with the testimony given on behalf of DEC's ratepayers, who advocate a prompt reduction in the Company's revenue requirement to account for the cost of service impact.

The AGO maintained that the extra $200 million increment sought by DEC should be rejected, because by deviating from the statutorily mandated ratemaking formula, DEC would establish rates that are inflated by design. The AGO asserted that fixing rates that are intended to over-collect revenues is contrary to the ratemaking formula in N.C. Gen. Stat. § 62-133(b) and (c), and violates key ratemaking principles. The AGO stated that the Commission's responsibility is to "fix such rates as shall be fair both to the public utilities and to the consumer." N.C. Gen. Stat. § 62-133(a). The AGO further stated that the statutory intent is that the Commission "fix rates as low as may be reasonably consistent" with Due Process constitutional considerations.[1] The AGO asserted that the burden of proof is on the utility to show that its proposed changes in rates are just and reasonable according to N.C. Gen. Stat. § 62-75; 62-134(c) and that DEC cannot meet that burden.

The AGO noted that Commission precedent and North Carolina case law support the prompt flow-through of tax reform benefits to utility ratepayers. The AGO noted that when Congress passed the Tax Reform Act of 1986, the Commission found that the significant reduction to the tax rate would "have an immediate and favorable impact on the cost of providing ... public utility services to consumers in North Carolina," and concluded that "[i]t is incumbent upon this Commission to take the appropriate action as required so as to preserve and flow through to ratepayers, as a reduction to public utility rates, any and all cost savings realized in this regard which would otherwise accrue solely to the benefit of the stockholders." Order Initiating Investigation In the Matter of the Tax Reform Act of 1986, issued October 22, 1986 in Docket No. M-100, Sub 113, at 1. The AGO noted that, affirming the Commission's final decision in that proceeding, the North Carolina Supreme Court observed that the purpose of the Commission's proceeding in 1986 was to "take the effect of the reduction in tax rates and flow it through to the ratepayers." State ex rel. Utils. Comm'n v. Nantahala, 326 N.C. at 197, 388 S.E.2d at 122.

The AGO stated that, similarly, when the North Carolina legislature adopted tax reform in 2013, it intended for the benefits of reduced state income taxes to be flowed through to ratepayers as the tax changes occurred. See In the Matter of Implementation of House Bill 998 – An Act to Simplify the North Carolina Tax Structure and to Reduce Individual and Business Tax Rates in Docket No. M-100, Sub 138.

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[1] State ex rel. Utils. Comm'n v. Duke Power Co., 285 N.C. 377, 388, 206 S.E.2d 269, 276 (1974) (Duke Power).

The AGO maintained that furthermore, although DEC has claimed that customers may be harmed by the reduction to its cash flow prompted by a reduction in rates, the evidence in support of that hypothetical position was not substantiated. The AGO stated that the Tech Customers witnesses Brown-Hruska and Strunk reviewed claims by DEC witness De May that the Company's funds from operations to debt (FFO/Debt) ratios would drop to the point that a downgrade would likely occur. The AGO stated that based on their review of the projected FFO/Debt ratios proffered by witness De May and the most recent credit assessment from Standard & Poors, they concluded that DEC's credit metrics would not be jeopardized by the elimination of the additional $200 million in cash flow. Tr. Vol. 26, p. 514.

The AGO noted that, rather, the Company's projections demonstrate that the Company is on track to maintain and even to exceed, after implementation of the Tax Act, FFO/Debt ratios in the range of 24 to 26 percent, which is the base case assumption relied upon by S&P before the Tax Act became law. Consequently, the AGO recommended that the Commission reject DEC's request for a $200 million annual increase in its revenue requirement.

The AGO noted that another impact of the federal income tax rate reduction is that it prompts a large reduction in the amount of accumulated deferred income taxes that DEC has accrued. The AGO stated that DEC acknowledges that customers should benefit from the excess accumulation. The AGO stated that, nonetheless, DEC proposes to spread out the return of most of the excess over many years, so that its rates are not reduced as much as they would be if the excess is returned promptly.

The AGO stated that it supports a return of the excess deferred taxes as soon as possible, but in no event longer than the initial recommendation of the Public Staff to return the excess deferred income taxes over 2 years because ratepayers will benefit immediately from the use of the amounts they are owed. The AGO argued that DEC has not supported its claim that any harm will fall to customers by the prompt return of the funds, and it is time for DEC to stop relying on excess revenues or a loan from its customers to maintain the overly flush cash flow that was provided under former tax deferral policies. The AGO asserted that the alternative of not returning dollars to consumers who struggle to pay their bills, or to consumers who would use their money for different purposes if given the opportunity, results in an undue burden on ratepayers and communities in North Carolina.

CIGFUR III stated in its post-hearing brief that the Commission should reject DEC's proposal to prolong the return of unprotected PP&E EDIT to ratepayers over a period of 20 years and should implement the Public Staff's proposal to return all unprotected EDIT over a five-year period.

CIGFUR III stated that in the early years of a given capital asset, the utility collects more in tax expense from ratepayers than it pays out to the IRS due to the difference in accelerated depreciation for tax purposes and straight-line depreciation for ratemaking purposes; that situation reverses once the ratemaking depreciation expense begins to exceed the tax depreciation. CIGFUR III noted that assuming that tax rates stay constant, over the life of a capital asset, the total tax expense paid by the ratepayers to the utility should match the tax expense the utility pays in federal taxes. CIGFUR III maintained that as a result of the differences in depreciation timing and because tax funds are ratepayer supplied, in the early years of a given capital asset ratepayers provide the utility an interest-free loan, reflected as a credit to the utility's ADIT liability account. CIGFUR III noted that due to the Tax Act, DEC's future tax liabilities will not be as high as anticipated when DEC filed its general rate case in August 2017, and the amount by which DEC's current ADIT balances exceed their future income tax liability because of the Tax Act are the EDIT at issue.

CIGFUR III stated that while certain EDIT have been designated by the IRS code as "protected" and are required to be normalized over the remaining life of the asset, the Commission has wide discretion in the timing and duration of the return of "unprotected" EDIT. CIGFUR III recommended that the Commission conclude that unprotected EDIT should be promptly flowed back to ratepayers; however, the Company proposes to delay returning what it designates as unprotected PP&E EDIT, although it concedes that this category of EDIT is not subject to IRS tax normalization rules. CIGFUR III stated that it opposes delayed return of unprotected EDIT and supports the Public Staff's recommendation that the unprotected EDIT be returned to ratepayers over 5 years.

CIGFUR III argued that the tax normalization rules are very clear and either EDIT is protected, or it is not. CIGFUR III asserted that the EDIT that the Company designates as "PP&E-related" is still clearly unprotected; a fact conceded by the Company. CIGFUR III stated that the Company's assertion that it should only return this PP&E-related unprotected EDIT over the same period of time it would have paid the funds to the IRS had the tax law not been passed is not supportable by any logical accounting or ratemaking principle, and should not dictate this Commission's decision as to what is a reasonable amount of time within which to return these funds to ratepayers. CIGFUR III asserted that these funds rightfully belong to the ratepayers and should be returned to them as soon as reasonably possible.

CIGFUR III maintained that while DEC stated that the delayed refund of unprotected EDIT is needed to protect its FFO/Debt ratio and thus its credit metrics, it has failed to offer compelling evidence in support of this justification. CIGFUR III asserted that to the contrary, Public Staff witness Hinton testified and concluded that, "it is unlikely that spreading the EDIT over five years will result in a debt rating downgrade and it is reasonable and fair to Duke's ratepayers and the Company." Tr. Vol. 22, p 277. As such, CIGFUR III urged the Commission to adopt the Public Staff's proposal to return all unprotected EDIT over 5 years.

CIGFUR III also recommended that the Commission reject DEC's proposal to "smooth out rate volatility" by slowing the flowback of benefits to ratepayers by accelerating the depreciation of ill-defined assets amounting to $200 million per year. CIGFUR III noted that DEC has requested this $200 million annual increase to its revenue requirements to collect expenses related to AMR meters, coal-fired plants, or coal ash clean up on an accelerated basis; specifically, the Company contended that its requested $200 million annual increase in its revenue requirement is required to mitigate the negative cash flow impact of the revenue requirement reductions resulting from the Tax Act and protects the Company's pre-Tax Act credit quality. CIGFUR III contended that, however, to the contrary, witnesses Strunk and Brown-Hruska, testifying on behalf of the Tech Customers, contended that:

> [T]he projected FFO/Debt ratios, adjusted so as to eliminate the request for an additional $200 million in cash flow, do not jeopardize the Company's credit metrics. Rather, the Company's projections demonstrate that the Company is on track to maintain and even to exceed – after implementation of the Tax Act – FFO/Debt ratios in the range of 24 to 26 percent, which is the base case assumption relied upon by S&P before the Tax Act became law. Consequently, we recommend that the Commission reject DEC's request for a $200 million annual increase in its revenue requirement.

CIGFUR III Brief, pp. 23-24.

CIGFUR III stated that as a result of the analysis performed by the Tech Customers witnesses and the Company's failure to present compelling evidence of financial harm, it contends that DEC's request to increase its annual revenue requirement by $200 million is unnecessary and should be rejected.

CUCA argued in its post-hearing brief that DEC's rates should be adjusted to give customers full credit for the reduction in the Federal corporate income tax rate from 35% to 21% contained in the Tax Act. CUCA asserted that giving the customers the full benefit of a 100% flow through of this federal income tax reduction will help to soften the economic blow to consumers' budgets that will result from any rate increase approved by the Commission in this case. CUCA noted that DEC, however, argued that the benefits of the Tax Act should not be 100% flowed through to the customers right away and instead, the customers should be required to accept a delayed payment of some of the benefits of the tax reduction while DEC makes other uses of the customers' money.

CUCA asserted that the "math in this situation does not require a rocket scientist to solve": Federal income tax rates are reduced from 35% to 21% and the "gross up" that DEC requires to account for income taxes is significantly reduced. CUCA stated that if the effective tax rates (like any other item of expense) go down, it has to follow that the utility's revenue requirement also must go down. CUCA Brief, p. 15. CUCA argued that the revenue requirement impact of a reduction in the federal corporate income tax rate from 35% to 21% is a finite, calculable amount. CUCA asserted that customers should immediately receive, as soon as any new rates for DEC become effective, the full benefit of this tax reduction. CUCA opined that DEC should not be able to place a hold on what is, fundamentally, the ratepayers' money by any sort of delayed refund mechanism. CUCA maintained that such a delay puts ratepayers in the position of having to pay "phony" or "phantom" income taxes as a part of the overall utility revenue requirement. CUCA Brief, p. 15.

CUCA noted that DEC argued that, unless it could delay reducing rates by the full amount of the tax reduction, it would be forced into a position of having to borrow working capital funds and that its credit rating could be seriously undermined. CUCA noted that the Supplemental Testimony of the Tech Customers witnesses clearly refutes this argument. CUCA stated that the supplemental testimony shows that DEC will not experience any funding difficulties and will not incur any sort of erosion or damage to its credit rating.

CUCA asserted that to the extent the Commission allows DEC, as DEC has requested, to delay the full impact of the Tax Act tax reductions, then the customers and ratepayers are, in essence, being required to provide an interest free loan to the DEC stockholders. CUCA argued that if the Commission allows this, then the amounts of the Tax Act tax refunds that are not immediately flowed through should bear interest, to be ultimately repaid to the customers, at an annual rate of not less than 10% of the value of the delayed refund during the time of such delay. CUCA stated that that is the only way in which the ratepayers can be made whole for the loan they would be forced to make to the DEC stockholders. CUCA stated that, in addition, if DEC is allowed to delay the full impact of the tax refund implemented by Congress and the President, this delay will tend to reduce the business, financial, and operating risks of DEC. CUCA argued that, therefore, in addition to the payment of interest, the Commission should reduce the rate of return on equity awarded to DEC because of the risk reduction.

The Justice Center et al. stated in their post-hearing brief that the recent changes to federal tax law give the Commission an opportunity to mitigate the impact of any rate increase on the Company's most vulnerable customers. The Justice Center et al. noted that DEC has collected a large pool of unprotected EDIT. The Justice Center et al. urged the Commission to direct $5 million of the EDIT to the Helping Home Fund, which provides efficiency upgrades to low-income customers, for each year of the period over which the EDIT is amortized to flow back to ratepayers. The Justice Center et al. argued that at the same time, the Commission should reject DEC's request to retain $200 million in ratepayer dollars per year as cash-flow protection for the Company.

The Justice Center et al. noted that at the Greensboro public hearing, the executive director of the NCCAA, Sharon Goodson, recommended that the Company contribute up to $5 million annually to the Fund. Tr. Vol. 2, pp. 21-22; Goodson Ex. 1. The Justice Center et al. asserted that a $5 million annual contribution from DEC's unprotected EDIT represents less than 14 percent of the total unprotected EDIT that will flow back to ratepayers, and a smaller percentage of the overall EDIT that is owed to ratepayers.

The Justice Center et al. maintained that there is precedent for using a regulatory liability for the benefit of customers to fund energy-efficiency investments for the utility's low-income customers. The Justice Center et al. noted that the Helping Home Fund itself was originally funded with $10 million of a $20 million regulatory liability from DEP held for the benefit of its North Carolina retail customers.

In addition, the Justice Center et al. stated that sound policy reasons support directing a meaningful portion of the unprotected EDIT for targeted investments in low-income energy efficiency, rather than simply flowing all of the funds to ratepayers through rebates or a decrement rider. The Justice Center et al. maintained that utility investments in energy efficiency help to alleviate high energy burdens faced by low-income households, particularly when those households are faced with rate increases. The Justice Center et al. argued that low-income households, racial minorities, renters, and low-income customers residing in multifamily buildings experience higher than average energy burdens, meaning that they pay a higher percentage of their income on energy bills than their counterparts. The Justice Center et al. asserted that the Southeast faces some of the highest energy burdens in the nation and that households with high energy burdens must face difficult trade-offs between paying utility bills and paying for other necessities such as food, prescriptions, transportation, and medical care. Tr. Vol. 8, pp. 33-38. The Justice Center et al. also stated that low-income households are more likely than the average household to have older and less efficient appliances. The Justice Center et al. stated that by lowering energy costs during periods of high demand, and avoiding or deferring the need to build or upgrade expensive new power plants and transmission infrastructure, investments in energy efficiency also bring system-wide benefits that are shared by all customers. The Justice Center et al. stated that each dollar invested in energy efficiency yields up to four dollars in benefits for customers.

The Justice Center et al. noted that at the evidentiary hearing in this matter, DEC witness Fountain recognized that it would be appropriate for the Commission to direct a portion of the unprotected EDIT for the benefit of low-income customers. The Justice Center et al. stated that when asked whether the Company would object to allocating a portion of unprotected EDIT to the Helping Home Fund, witness Fountain agreed that the Commission could use a portion of the unprotected EDIT for low-income energy-efficiency measures: "the Tax Act is a tool that the Commission has before it that it can use to mitigate customers' rate impacts in a variety of different ways, and...there could be some considerations for low-income customers....it's a very useful tool for the Commission to be able to have." Tr. Vol. 7, p. 57. The Justice Center et al. stated that, moreover, witness Fountain agreed that there was precedent for using a regulatory liability held by the Company for the benefit of ratepayers to support the Helping Home Fund. Id. at 58. The Justice Center et al. noted that Commissioner Patterson asked witness Fountain whether the Helping Home Fund has been favorably received and whether DEC had considered making additional contributions to the Fund in the context of this general rate case. Tr. Vol. 9, pp. 111-12. The Justice Center et al. maintained that while witness Fountain praised the program, he acknowledged that the Company has made no commitment to further support the program from shareholder dollars or otherwise in this rate case.[1] Id. The Justice Center et al. stated that similarly, Commissioner Clodfelter and Chairman Finley urged DEC to consider additional ways to meet the needs of low-income customers, including consideration of the Ohio Percentage of Income Payment Plan and the Missouri "Dollar More" program. Tr. Vol. 9, pp. 97-98; 114-15.

The Justice Center et al. maintained that DEC's failure to offer any assistance to its low-income customers to mitigate the effects of its proposed increase in rates and charges should be relevant to the Commission's decision whether to grant any of those requested increases. See, e.g., Order Granting General Rate Increase, Docket No. E-2, Sub 1023, p. 82 (May 30, 2013) (finding that funding of low-income assistance programs "is a just and reasonable measure to mitigate the impact of the proposed rate increase on . . . low-income customers"). The Justice Center et al. noted that the potential impact of new rates on customers is a "critical consideration" in the Commission's determination on whether to accept those new rates. Cooper, 366 N.C. at 495, 739 S.E.2d at 548 (holding that the Commission must consider the impact of changing economic conditions on customers when determining return on equity for a public utility). The Justice Center et al. asserted that to the extent that the Commission grants any component of DEC's request for a rate increase, it would be reasonable to order the allocation of $5 million per year of DEC's unprotected property, plant, and equipment EDIT to the Helping Home Fund for as long as that EDIT is amortized to flow back to ratepayers.

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[1] On June 1, 2018, DEC made a shareholder-funded commitment of $4 million for programs including those to assist low-income customers.

Kroger asserted in its post-hearing brief that customers should receive the full benefit of the tax savings provided by the Tax Act. Kroger noted that the reduction in the corporate income tax rate per the Tax Act will reduce DEC's federal income tax expense for regulatory purposes and that this reduction in tax expense should directly reduce the revenue requirement in this case. Kroger stated that viewed in isolation, this single component of the change in tax law, i.e., the reduction in the tax rate from 35 percent to 21 percent, reduces DEC's revenue requirement by a significant amount.

Additionally, Kroger noted that the Tax Act has implications for DEC's ADIT. Kroger stated that DEC accumulates these deferred income taxes in the ADIT on its regulatory books in an amount equal to this anticipated future tax liability. Kroger asserted that now that the corporate income tax rate has been reduced by 40 percent, DEC's anticipated future tax liability has also decreased by a comparable amount. Kroger noted that as of January 1, 2018, when the new tax rates became effective, a substantial portion of the ADIT on DEC's books will be considered to be "excess" ADIT. Kroger asserted that this excess ADIT should be returned to customers.[1]

Kroger recommended that the Commission reduce the revenue requirement in an amount that provides customers with the full benefit of the tax savings provided by the Tax Act and that the Company's revenue requirement in this case should be adjusted to reflect the direct impact to its cost-of-service and excess ADIT should be credited to customers starting with the rate effective period in this general rate case.

NCLM noted in its post-hearing brief that its witness Brian W. Coughlan provided testimony that DEC's rates should be adjusted downward to account for the significantly lower corporate income tax rates that DEC will pay since the enactment of the Tax Act. Tr. Vol. 8, pp. 105-107. NCLM noted that its Settlement Agreement with DEC did not resolve the issues raised by NCLM as to adjusting all rates downward to account for the lower corporate income tax rates in the Tax Act. NCLM stated that DEC's unanticipated tax savings should be used to mitigate any rate increase.

NCLM stated that its witness Coughlan addressed this issue in his testimony to supplement the Commission's work in Docket No. M-100, Sub 148. Tr. Vol. 8, pp. 105-107. NCLM noted that witness Coughlan simply asserted that, "[t]he new tax cuts should be taken into account now. The new tax rates take effect before the new electric rates will take effect. If the new tax rates are not accounted for at this time, DEC will have significantly higher than expected and appropriate earnings, and DEC customers will pay unfairly high rates between now and the next rate case." Id. at 106. NCLM respectfully requested that the Commission allow rate payers to benefit from the tax cuts to the maximum extent possible in this docket.

The Tech Customers asserted in their proposed order and post-hearing brief that the Commission is required in this general rate case to, among other things, account for the Company's operating expenses for the test year, taking into account "evidence ... tending to show actual changes in costs". See, e.g., N.C. Gen. Stat. §§ 62-133(b)(3) and (c). The Tech Customers stated that given this requirement, the effects of the Tax Act as to the rates charged by the Company

[1] Direct Testimony of Kevin Higgins, pp. 6-7.

should be addressed in this general rate case rather than the separate, generic proceeding that the Commission has initiated in Docket No. M-100, Sub 148. The Tech Customers asserted that the Public Staff's proposal for return of EDIT best balances the need to return tax overcollections to ratepayers as promptly as possible with the appropriate regulatory goals of avoiding adverse rate impacts for ratepayers and allowing sufficient time for DEC to manage its cash flow so as to avoid negative impacts to its credit metrics.

Further, the Tech Customers maintained that DEC's proposal to offset the reduction in its revenue requirement resulting from the Tax Act with $200 million in accelerated depreciation expense is not sufficiently supported in the record and raises significant legal and practical concerns. The Tech Customers argued that a decline in revenues resulting from a change in federal tax law does not, by itself, support the adoption of offsetting revenue increases where those increases are not independently justified and supported.

The Tech Customers noted that given that the issue relating to the implementation of federal tax reform was introduced into this proceeding after the filing of testimony by the parties, the parties have addressed this issue through supplemental testimony, examination at hearing, and in post-hearing briefing.

The Tech Customers noted that they offered Supplemental Testimony of witnesses Strunk and Brown-Hruska. The Tech Customers witnesses evaluated the reasonableness of DEC's contention that a $200 million annual increase in spending was necessary to support its credit metrics. The Tech Customers stated that based on the projected FFO/Debt ratios offered by DEC witness De May and a review of the most recent credit assessment of Standard and Poor's, witnesses Strunk and Brown-Hruska found that DEC's projected FFO/Debt ratios, adjusted to eliminate the request for an additional $200 million in cash flow, do not jeopardize the Company's credit metrics. Tr. Vol. 26, p. 514. The Tech Customers stated that, instead, their analysis study shows that DEC is on track to maintain, or even exceed, its stated FFO/Debt ratio goal after implementation of federal tax reform. Id. The Tech Customers maintained that witnesses Strunk and Brown-Hruska also compared DEC's FFO/Debt ratio to those of comparable companies, including those in witness Hevert's proxy group, and found that DEC's ratios are in line with, or above, those of the comparable companies and that its FFO/Debt ratios are among the healthiest among the proxy group companies both on a current and projected basis. Id. at 516-517. Based on this analysis, the Tech Customers noted that their witnesses concluded that DEC's rationale for its proposal was inconsistent with the financial forecasts it has provided in its own exhibits and not necessary to protect its current credit standing. Id. at 519.

The Tech Customers stated that the Commission is required in this general rate case to, among other things, account for the Company's operating expenses for the test year taking into account "evidence . . . tending to show actual changes in costs." See, e.g., N.C. Gen. Stat. § 62-133(b)(3) and (c). The Tech Customers asserted that this statute suggests, if not mandates, that the Commission implement tax reform in this proceeding.

Further, the Tech Customers stated that they agree with the Public Staff's recommendations concerning EDIT. The Tech Customers stated that they do not find support in accounting or ratemaking principles for the distinction in unprotected EDIT advocated by DEC. The Tech Customers stated that the PP&E assets for which DEC seeks a 20-year amortization period, like other unprotected EDIT, are not subject to IRS normalization rules. The Tech Customers asserted that Congress intentionally excluded EDIT from unprotected assets from the treatment given to protected EDIT because the excluded assets do not have normal useful lives. The Tech Customers noted that DEC asserted that unprotected PP&E EDIT is similar in nature to protected EDIT (which is also related to PP&E) and therefore it is reasonable to flow it back over a similar period. Tr. Vol. 5, p. 78. However, the Tech Customers stated that they can discern no principled basis for distinguishing between the assets in the manner proposed by the Company and an examination of the specific assets in this category suggests that they include assets (e.g., casualty loss, depreciation lag, AFUDC debt, pension cost) with highly uncertain accounting lives. See DEC Response to Public Staff Data Request No. 155-3, filed March 22, 2018.

Moreover, the Tech Customers argued that 20 years is simply too long a period over which to return over-collected ratepayers' money, and DEC has offered no evidence suggesting otherwise. In this regard, the Tech Customers stated that they are sympathetic to the need to return tax over-collections as expeditiously as possible. See, e.g., Buckeye Pipe Line Co., 13 FERC ¶ 61267, 61594 (1980) ("Millions of the Americans who use [electricity] live in poverty or on very tight budgets. Those people are in no position to lend money to anybody. A state of affairs that compels them to supply . . . electric companies with long-term credit in amounts that may sometimes seem minuscule on a per capita basis to the affluent but that are almost always material to the poor and to those who are just getting by cannot be viewed complacently.").

The Tech Customers noted that DEC has also raised concerns about the impact of the EDIT flowback on its cash flow that it speculates could negatively impact its credit metrics. Tr. Vol. 5, pp. 67-83. While the Tech Customers acknowledged the concerns raised by DEC, as well as the benefits that ratepayers derive from the Company's strong credit profile, the Tech Customers recommended that the Commission conclude that DEC's evidence on this point is not compelling or convincing.

Moreover, the Tech Customers noted that the Company's concerns over cash flow and credit metrics are mitigated, to an extent, by the Public Staff's five-year flow back proposal that provides the Company with the benefit of removing the total amount of the unprotected EDIT credit from the rate base in the current case, which benefits the Company by increasing rates and thereby moderating any cash flow issues, to the extent they may arise. The Tech Customers asserted that the financing cost to the Company will be imposed ratably over the period that the EDIT is returned through the levelized rider.

Finally, the Tech Customers recommended that the Commission conclude that DEC's proposal to offset the reduction in its revenue requirement resulting from the Tax Act with \$200 million in accelerated depreciation expense is not sufficiently supported in the record and raises significant legal and practical concerns. The Tech Customers maintained that a decline in revenues resulting from a change in federal tax law does not, by itself, support the adoption of offsetting revenue increases where those increases are not independently justified and supported. The Tech Customers asserted that aside from the desire to offset reductions resulting from the change in tax law, the Company has not offered any principled explanation of the need for accelerated depreciation nor has it offered any basis for applying special depreciation rates for particular assets. The Tech Customers noted that DEC does articulate concerns about adverse rate impacts on consumers, but the Tech Customers support a five-year return of EDIT that will help ameliorate adverse impacts resulting from the return of EDIT. Moreover, the Tech Customers maintained that as to DEC's credit metrics, record evidence suggests that DEC's projected FFO/Debt ratios, adjusted to eliminate the proposed additional $200 million in cash flow, will not jeopardize the Company's credit metrics. Tr. Vol. 26, p. 514. The Tech Customers stated that, instead, evidence suggests that DEC will be on track to maintain, or even exceed, its stated FFO/Debt ratio goal after implementation of federal tax reform without an annual $200 million revenue increase. Id.

In light of the parties' testimony and all of the evidence presented, the Commission finds and concludes that it is appropriate to: (1) recognize a $211,512,000 per year reduction in DEC's revenue requirement to reflect the current 21% Federal corporate income tax rate; (2) deny DEC's proposed $200 million per year credit metric mitigation measure; and (3) allow DEC to continue to maintain all EDIT related to the Tax Act in a regulatory liability account for three years or until its next general rate case, whichever is sooner, at which point it will be returned to DEC's customers with interest reflected at the overall weighted cost of capital approved in this case of 7.35%. The Commission concludes that this approach appropriately balances the interests of DEC and its ratepayers.

The evidence shows that there is some agreement between the parties regarding how to implement the effects of the Tax Act. The Company and the Public Staff agree upon the revenue requirement effect of the decrease in the corporate income tax rate, the repeal of the manufacturing tax deduction, and the elimination of bonus depreciation. No party disputes the amounts presented by the Company and the Public Staff regarding the impact of the Tax Act on these issues, and the Commission finds and concludes that the revenue requirement changes presented by the Company and the Public Staff related to these issues are appropriate and should be approved. This decision results in a $211,512,000 per year reduction in DEC's revenue requirement.

Further, the Commission gives great weight to the testimony of the Public Staff, the AGO, CIGFUR III, the Justice Center et al., Kroger, NCLM, and the Tech Customers that DEC's proposed $200 million per year credit metric mitigation measure is inappropriate and should be denied. Therefore, the Commission declines to allow the Company to include an additional $200 million in its annual revenue requirement for the purpose of offsetting the impacts of the Tax Act on DEC's revenue requirement.

The Commission agrees with the Public Staff that DEC's request amounts to essentially eliminating the benefit of the corporate income tax decrease on the Company's ongoing expenses. DEC's request for this extraordinary relief was presented in very vague and uncertain terms; the Company simply mentioned a few possible uses for the additional $200 million in annual revenue. None of the Company witnesses could even articulate the reason for the $200 million number, nor could they provide a breakdown of what that number represents, other than that witness De May felt the number to be appropriate. The Commission further agrees with the Tech Customers that a decline in the tax rate does not support the adoption of an offsetting revenue requirement increase that is not independently justified and supported. The Commission also agrees with the Tech Customers that adoption of the $200 million proposal would raise significant legal and practical concerns. Moreover, as noted by the Public Staff, the request was not time-limited; in theory, the additional $200 million in revenue requirement would equate to $1 billion after five years. Finally, the Commission finds and concludes that offsetting known and measurable reductions in taxes to be paid going forward against the recovery of unknown ongoing coal ash basin closure costs as ultimately proposed by DEC in its Post-Hearing Brief and Proposed Order in this docket in order to delay reflecting the current Federal corporate income tax rate in base rates constitutes inappropriate ratemaking.

The Commission finds that the $200 million in additional annual revenue requirement appears solely designed to arbitrarily inflate the Company's revenue requirement beyond the actual cost of service. The Company essentially seems to be telling ratepayers that they can receive the reduction in the tax rate, but they have to pay most of it back through accelerated depreciation expenses. The Commission rejects this proposal as arbitrary. The Commission is confident that the Company's management can navigate this situation without artificial and arbitrary adjustments to annual revenue requirement. The Commission concludes that the Company's request for an additional $200 million per year as a credit metric mitigation measure is not supported by the preponderance of the evidence and therefore is denied.

Finally, the Commission notes that DEC filed its rate case application in August 2017, four months before the enactment of the Tax Act. The Commission finds that it is appropriate to recognize this fact in rendering its final decision in this matter. The Tax Act is the most significant federal tax legislation since the 1986 Tax Act enacted some 30 years ago. Based on this fact and finding that the evidence presented by DEC concerning its credit metrics and a possible credit downgrade merit some weight, the Commission concludes that DEC shall maintain all of its EDIT in a regulatory liability account pending flow back of that liability to DEC's ratepayers with interest reflected at the overall weighted cost of capital approved in this case of 7.35% in three years or in DEC's next general rate case proceeding, whichever is sooner. If DEC has not filed an application for a general rate case proceeding by June 22, 2021, it shall file its proposal by that date to flow back to its ratepayers both the protected and the unprotected EDIT generated due to the Tax Act. The federal EDIT flowback proposal should include all workpapers that support the proposed calculations. The Public Staff is specifically requested to file comments on the proposal by no later than July 22, 2021. Other parties also may file comments on the proposal by no later than July 22, 2021.

The Commission notes that in the generic rulemaking proceeding established by the Commission to address the recent changes in the State corporate income tax rate (Docket No. M-100, Sub 138), the Commission concluded that EDIT for all utilities, as appropriate, were to be held in a deferred tax regulatory liability account until they could be amortized as reductions to income tax expense for ratemaking purposes in each utility's next general rate case proceeding. The Commission stated that it agreed with PSNC Energy's comments in that docket that recognizing the amortization of the EDIT in the next general rate case of a utility would provide for certainty as to the amount to be amortized instead of having to base the flow-back calculation on an estimate. In that proceeding, no party objected to that option of handling the EDIT. In addition, the Commission noted in its May 13, 2014 Order in the generic proceeding that both Carolina Water Service, Inc. of North Carolina (CWSNC) and Aqua had had open rate case proceedings at the time the generic State tax docket was initiated. A rate order was issued in CWSNC's rate case docket on March 10, 2014, and a rate order was issued in Aqua's rate case docket on May 2, 2014. The Commission concluded in the May 13, 2014 Order that the expense piece of the State corporate income tax rate change was reflected in the rates established in the CWSNC and Aqua open rate case proceedings, but that CWSNC and Aqua needed to adhere to the findings on State EDIT outlined in the May 13, 2014 Order. The May 13, 2014 Order concluded for the State EDIT that each utility was to hold the State EDIT in a deferred tax regulatory liability account until they could be amortized as reductions to income tax expense for ratemaking purposes in each utility's next general rate case proceeding. The Commission's decision herein is reasonably consistent with the treatment of CWSNC and Aqua in the generic State corporate income tax proceeding.

Further, the Commission notes that this process used in Docket No. M-100, Sub 138 has worked well and customers received or are receiving EDIT related to the State corporate income tax rate changes. In fact, in this proceeding, DEC and the Public Staff stipulated to begin returning (four years after the Commission's State EDIT decision in the May 13, 2014 Order in the generic rulemaking docket) to DEC's customers the State EDIT through a four year decrement rider.

In addition, the Commission notes that in the Commission's 1986 federal corporate income tax law change generic rulemaking proceeding (Docket No. M-100, Sub 113), the Commission concluded in its October 20, 1987 Order to Require Filing of Tariffs to Reduce Rates and Refund Plans to Effect Flow Through of Tax Savings for Those Regulated Companies not covered by Specific Orders on This Matter (1987 Order), as follows:

> [t]hat the appropriate amortization of accumulated excess deferred income taxes will be considered in each company's next general rate case or such other proceeding as the Commission may determine to be appropriate. Any additional amounts relating to the adjustment that should have been made by the company for the flowback of excess deferred income taxes shall be placed in a deferred account and should ultimately be refunded to ratepayers with interest.

1987 Order. Although this conclusion was reached in a generic rulemaking proceeding, the Commission concludes that the fact that DEC had already filed its rate case application before the enactment of the Tax Act in this instant proceeding, it is appropriate to follow this same process for returning Federal EDIT to DEC's ratepayers.

However, the Commission, in its discretion, concludes that it is appropriate in this case to set a time limit for DEC to retain all of the EDIT generated due to the Tax Act. The Commission concludes that it is preferable to address this EDIT in a rate case proceeding; but due to the sheer magnitude of the EDIT that in total is approximately $2.14 billion, the Commission finds that DEC must begin the process to flow back the EDIT to ratepayers no later than three years from the date of this Order (or sooner if DEC files a rate case in less than three years). Therefore, the Commission concludes that if DEC has not filed an application for a general rate case proceeding by June 22, 2021, it shall file its proposal by that date to flow back to its ratepayers both the protected and the unprotected EDIT generated due to the Tax Act. The federal EDIT flowback proposal should include all workpapers that support the proposed calculations. The Public Staff is specifically requested to file comments on the proposal by no later than July 22, 2021. Other parties also may file comments on the proposal by no later than July 22, 2021.

In conclusion, the Commission finds it appropriate to: (1) recognize a $211,512,000 per year reduction in DEC's revenue requirement to reflect the current 21% Federal corporate income tax rate; (2) deny DEC's proposed $200 million per year credit metric mitigation measure; and (3) allow DEC to continue to maintain all EDIT related to the Tax Act in a regulatory liability account for three years or until its next general rate case whichever is sooner at which point it will be returned to DEC's customers with interest reflected at the overall weighted cost of capital approved in this case of 7.35%. The Commission concludes that this approach appropriately balances the interests of DEC and its ratepayers.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 59-64

The evidence supporting these findings of fact and conclusions is found in the Company's verified Application, DEC's Petition for an Order Approving a Job Retention Rider (JRR), filed on August 14, 2017, in E-7 Sub 1152 (JRR Petition), the testimony of Company witness Pirro, the testimony of Public Staff witness McLawhorn, the testimony of other witnesses, the exhibits of witness Pirro, and the entire record in this proceeding. The Commission takes judicial notice of the Company's Initial and Reply Comments filed in Docket No. E-100, Sub 73 where the Company outlined the conditions that led to the loss of industrial jobs and where the Commission issued establishing guidelines on December 8, 2015. (JTR Order)

In its Petition, DEC requests approval of its JRR, a five-year pilot program for industrial customers that is intended to curtail further loss of industrial jobs in DEC's service territory. Petition, at p. 1. The Commission acknowledged the JRR's goal to stem further loss of industry, industrial production and industrial jobs in DEC's service territory as an important policy goal for North Carolina when it adopted the Guidelines for Job Retention Tariffs in Docket No. E-100, Sub 73. Petition at p. 3. Company witness Pirro testified in support of the Company's proposed JRR. Witness Pirro explained that the JRR will benefit ratepayers by retaining North Carolina jobs and strengthening local economies thereby aiding the commercial and residential markets. Tr. Vol. 19, p. 95. Since 2014, 50 manufacturing facilities served by Duke Energy have ceased operation in North Carolina. Id. at 78, 90. Witness Pirro states that the Company's IRP Update, filed on September 1, 2017 in Docket No. E-100, Sub 147, demonstrates the continuing struggles of manufacturing in North Carolina. Tr. Vol. 19, p. 90. He testifies that "[t]he Plan shows a steady decline in the number of industrial customers receiving electric service and our expectation [is] that even by 2023 industrial sales will still be below actual pre-recession sales realized in 2007." Id.

Witness Pirro also explained the eligibility requirements for the proposed JRR. Customers that use electric power as a principal motive power for the manufacture of a finished product, the extraction, fabrication or processing of a raw material, or the transportation or preservation of a raw material or a finished product would be eligible for the Company's proposed JRR. Id. at 90-91. Furthermore, in order to qualify for JRR, industrial customers must show that they (i) have or are considering the ability to shift production from their facilities to facilities in other states or countries; (ii) are considering a need to reduce the employment level at their facilities due in whole or in part to the impact of electricity cost; (iii) intend to reduce or are presently evaluating reduction of production levels or load due in whole or in part to the impact of electricity cost; or (iv) have load that is otherwise at risk of loss. Petition at p. 5. Additionally, eligible customers must have an aggregate electrical load of 3,000 kW or greater, in addition to other conditions described in the Petition and proposed JRR. Tr. Vol. 19, p. 91.

In its Petition, the Company does not seek recovery of the revenue reduction resulting from implementation of the JRR at this time, but instead requests deferral accounting with interest on the amount in excess of the $4.5 million that the Company will absorb on a one-time basis. Petition at p. 3.

CUCA witness O'Donnell testified in support of the Company's proposed JRR. Witness O'Donnell testified that if DEC continues to lose industrial load, the fixed costs of operating the DEC system will be shifted to the remaining customers in an amount even greater than the average 0.74% cited in DEC's Petition. Tr. Vol. 18, pp. 54-55. For example, witness O'Donnell calculated that if the Company's manufacturing load completely eroded, the remaining customers' rates would increase by over 16% annually. Id. at 55. He concluded that it would be much less harmful to residential customers to pay a 0.74% increase for five years than to have a permanent 16.22% increase. Id.

CIGFUR III witness Phillips also testified in support of the Company's proposed JRR. Witness Phillips testified that the Company's proposed JRR follows the Guidelines for Job Retention Tariffs issued by this Commission on December 8, 2015 in Docket E-100, Sub 73, and that the proposed JRR is in the public interest, and recommended that the Commission approve it. Tr. Vol. 26, p. 280. Witness Phillips testified that his review of DEC's historic and projected growth in customers indicated that within the 2007 to 2032 timeframe, the Company will see residential customers increase by 32.2%, commercial customers increase by 23.3%, and industrial customers decrease by 28.6%. Id. at 281. Witness Phillips testified that the proposed JRR will benefit all customers because "[i]f industrial load is lost, DEC would need to recover a larger portion of fixed costs from its remaining customers, resulting in higher electric rates for these customers." Id. at 282. Therefore, preserving jobs and industrial load through the Company's proposed JRR will strengthen the economy and keep electric rates lower for DEC's non-industrial customers. Id. Witness Phillips also testified that the Commission's guidelines in Docket No. E-100, Sub 73 do not exclude pipeline customers that are also important to the North Carolina economy. Id. at 283. Therefore, he testified that it would be unreasonable to impose restrictions on the Company's proposed JRR that exclude those customers. Id. at 284.

While the Public Staff is supportive of the JRR and believes that it is in the public interest, witness McLawhorn expressed several concerns regarding the proposed rider. Tr. Vol. 20, pp. 141-46. First, witness McLawhorn expressed concern with the availability of the rider to customers involved in the "transportation or preservation of a raw material of a finished product," which is understood to include gas pipeline customers. Id. at 141-42. He noted that pipelines are different than other industrial manufacturing facilities in that pipelines are fixed investments that are not easily relocated to another area, and unlike other industrial manufacturers, pipelines do not produce a finished product. Id. at 142. He recommended this disputed phrase be eliminated from the availability section of Rider JRR-1. Second, he argued that there are no specific criteria designated for use by the Public Staff to evaluate customer employment and financial records to aid in evaluating an applicant's justification for seeking the JRR thus depriving the Public Staff of the ability to verify the truthfulness of the information. Id. at 142-44. He also opposed the Company's request for deferral accounting of the revenue loss and the Company's proposal for sharing the discount between the Company's shareholders and ratepayers. Id. at 146. Lastly, witness McLawhorn recommended that the requirement that the discounted revenue must be used to retain jobs in North Carolina be more prevalently displayed in the Application form and that the language in the compliance filing clearly identify the length of the JRR from initial approval. Id. at 145-46.

Despite these concerns, the Public Staff generally supports the Company's proposed JRR, concluding that the rate reduction it provides for industrial customers would "assist them in maintaining jobs and load in North Carolina." Id. at 139-40. Witness McLawhorn testified that the Company's proposed JRR complies with the Commission's Guidelines for Job Retention Tariffs set forth in its December 8, 2015 order in Docket No. E-100, Sub 73. Tr. Vol. 20, pp. 134-38. Witness McLawhorn also testified that the proposed JRR is not unduly discriminatory because it is designed to reach the largest industrial customers, which impact other commercial and residential customer classes. Tr. Vol. 20, p. 138. Witness McLawhorn further stated that the proposed JRR "provides for a balancing of benefits and costs between those customers eligible for [JRR] and those that will bear the reduction in revenue that result from implementation of the rider." Id. at 139. Lastly, witness McLawhorn recommended that the impact of the rate discount be recovered from all retail ratepayers, including the customers eligible for the rate discount. Id. at 147.

Commercial Group witnesses Chriss and Rosa testified in opposition to the Company's proposed JRR. Witnesses Chriss and Rosa state that the proposed JRR fails to comply with Commission guidelines by limiting applicability to a subset of industrial customers and the rigor of verifying customer attestations is unclear. Tr. Vol. 26, p. 547. Witnesses Chriss and Rosa further request that if the JRR is approved, that it be extended to non-industrials that also provide jobs and have aggregate loads of 3,000 kW or greater. Id.

In its post-hearing Brief, Commercial Group continues to advocate a denial of the JRR. However, Commercial Group recognizes that the Commission approved a more limited JRR for DEP in DEP's rate case which included five safeguards, which the Commercial Group contends should be adopted in this case if approved. Commercial Group submits that the JRR would violate N.C. Gen. Stat. § 62-140(a) because it would unjustly discriminate among customers having an aggregate load of at least 3 MW based solely on whether the customer is an industrial customer. Commercial Group contends that this is a return to the Standard Industrial Classification (SIC) code distinctions that the Commission found discriminatory and rejected in prior proceedings. Commercial Group states that the Commission stated its concern in its final Order in DEC's 2011 rate case, Docket E-7 Sub 989, regarding the reasonableness and fairness of maintaining a rate differential based largely on labels such as the SIC codes. Commercial Group quotes N.C. Gen. Stat. § 62-140(a), and states that the legal standard is not whether a public utility can subject a customer to an unreasonable prejudice or disadvantage if doing so would be an advantage to other customers or the utility. Rather, the legal standard is that the public utility cannot grant any unreasonable preference or subject any person to any unreasonable prejudice or disadvantage. Further, Commercial Group contends that industrial customers are not a separate class of service because both industrial and commercial customers are members of the same OPT-V class, and that many non-industrial ratepayers in these classes have an aggregate load of at least 3 MW. According to Commercial Group, where the JRR's only distinguishing characteristic is industrial status, the JRR remains as unlawful and unduly discriminatory as the preference for OPT industrial customers that the Commission previously rejected, and, therefore, the JRR as proposed should be rejected as well.

In addition, Commercial Group states that the proposed JRR definitions and parameters that DEC selected provide only an illusion of being reasonable criteria for determining which customers should receive a rate subsidy. As an example, Commercial Group contends that the applicant could simply state that it has at some time in the past thought about obtaining the ability to move a portion of its operations out of state, but the applicant need not presently have such ability, presently plan to move operations out of state, nor be in such financial condition that jobs would be lost but for a JRR subsidy. Commercial Group further notes that the applicant does not need to maintain existing levels of employment, but instead chooses a level of employment that it states it will maintain, even if the level is lower than its present level.

Commercial Group notes that DEC witness Hevert gave convincing testimony that economic conditions in North Carolina have improved substantially since DEC's last rate case in 2013, and since the Commission adopted job retention guidelines in 2015. The unemployment rate in North Carolina and DEC's service territory has fallen substantially during these periods. Tr. Vol. 4, pp. 161, 165. Further, the correlation between the drop in unemployment in North Carolina and more broadly across the United States has been very high. Id. at 165. Moreover, DEC industrial customers already receive competitive rates that are below the national average and below the average in the Atlantic South region.

Commercial Group questions whether there will be a means to assess the effectiveness of the JRR. Commercial Group cites the testimony of Public Staff witness McLawhorn regarding the report that DEC will be required to file, and states that the report will not provide any reliable, independently verifiable information to determine the success or failure of the JRR. Based on the uncertainty of verifiable results from the JRR, Commercial Groups requests that the Commission should require the same safeguards that it required of DEP for its JRR in DEP's most recent rate case.

Company witness Pirro's rebuttal testimony responded to the concerns raised by other witnesses related the Company's proposed JRR. Witness Pirro agreed with the Public Staff's concern regarding difficulty evaluating customer financial and employment records. Tr. Vol. 19, p. 92. To address this concern, witness Pirro explained that DEC will impose a requirement that an officer of the customer sign the application and the signature be notarized. Id. Witness Pirro also noted that the guidelines don't require a demonstration of financial distress, but the discounted revenue must contribute to job retention in North Carolina. Id.

Additionally, witness Pirro testified regarding the inclusion of customers involved in the "transportation or preservation of a raw material of a finished product", that this language was included to allow the JRR to apply primarily to gas pipeline customers. Id. at 92. He stated that pipeline customers have expressed concerns with electricity costs and have requested rate relief to aid in their North Carolina operations. Id. DEC believes that it is reasonable to include this type of customer with manufacturing facilities when applying the JRR. Id.

Witness Pirro further testified that deferral accounting was requested because the timing and magnitude of the revenue reduction is unclear. Id. at 93. "The use of deferral accounting allows the Company to assess the true impact of the rider and seek recovery at a later date when revenues are more certain." Id. at 93-94. Witness Pirro also disagreed with witness McLawhorn's recommendation that the Company's shareholders absorb $4.5 million every year the rider is in effect. Id. at 95. Witness Pirro testified that the JRR will benefit ratepayers by retaining North Carolina jobs and strengthening local economies thereby aiding the commercial and residential markets. Id. While the Company's shareholders are willing to absorb a portion of the revenue reduction in the first year to implement the program, a requirement that shareholders absorb this cost in subsequent years would deprive the Company of a reasonable opportunity to recover its just and reasonable costs. Id.

Lastly, Witness Pirro agreed with witness McLawhorn's requested two changes to the application form and tariff. Id. at 93. He explained that the Company does not oppose the relocation of the statement regarding the discounted revenue being used to retain jobs in North Carolina to a more prevalent location in the Application. Id. The Company also does not object to more clearly identifying that the Rider terminate and no longer be available for service 5 years from the effective date of the Rider. Id.

In the Stipulation, the Company and the Public Staff agreed that "the Company's proposed Job Retention Rider generally complies with the Commission's guidelines adopted in Docket No. E-100, Sub 73, but two issues remain to be decided upon by the Commission: (1) whether companies involved in the transportation or preservation of a raw material or a finished product (e.g., pipeline customers) should qualify; and (2) how or if the Job Retention Rider should be funded after the expiration of the initial year's $4.5 million shareholder contribution." Stipulation, § II. c.

Except for the two unresolved issues stated above, the Stipulating Parties have agreed to the proposed JRR as described by witness Pirro in his rebuttal testimony, and further agreed that JRR revenue credits shall be recovered through a JRR Recovery Rider (JRRR) from all retail customers concurrent with JRR implementation, which is anticipated to occur approximately six months following the Commission's decision. Id. at 11, 13. The Stipulation provides that JRR and JRRR revenues shall be reported to the Commission annually and the JRRR shall be reviewed and will be subject to adjustment annually coincident with the September fuel adjustment to match anticipated recovery revenues and true-up any past over-or under-recovery. Id. at 13. Additionally, due to the uncertain date of implementation, compliance tariffs shall be filed prior to implementation of the JRRR and customers shall be notified by bill insert or message upon implementation. Id.

Company witness Pirro filed testimony and exhibits in support of the Stipulation. In his settlement supporting testimony, he explains that the recovery rate under the JRRR is set at $0.00041 per kWh to recover the first year of impact, less the $4.5 million absorbed by the Company, reduced by 10% for application lag. Tr. Vol. 19, pp. 107-08. Witness Pirro further testified that the JRRR is intended to keep the Company revenue neutral with respect to the JRR, other than the one-time $4.5 million contribution from shareholders, over the 5-year pilot period, and, if needed, a final true-up shall be applicable upon termination of JRR. Id. at 108.

The Commission finds and concludes that the Company's proposed JRR as modified by this Order is just and reasonable to all parties based on all of the evidence presented. The Commission finds that the continued loss of industrial jobs in DEC's service area will have a detrimental effect on the State. The Commission views the Company's proposed JRR as an effort to retain industrial jobs in North Carolina and concludes that implementation of the rider is in the public interest. As with other economic development tariffs previously approved by this Commission, approval of the JRR is based in part on an evaluation of the expected economic benefits resulting from the tariff. The Commission has considered the economic impact of the continuing decline of the North Carolina industrial base as well as the impact of the recovery rider on non-participating ratepayers, and concludes that the JRR strikes the appropriate balance between the two. The Commission concludes that by limiting the availability of the JRR to industrial customers, the Company has minimized the effect on non-participants while assisting the group of customers that are most in need of assistance. To further minimize the impact to non-participants and to achieve the goal of the JRR in the most cost-effective manner, the Commission shall limit the JRR to a one-year pilot, with the option of renewal for one additional year upon a showing that the JRR is achieving the intended objectives. Requiring the Company to show the Commission the effectiveness of the JRR in the rider proceeding removes any concerns expressed by the Commercial Group regarding measurement and verification. This reduction in the number of years for the pilot to one-year with the opportunity for a second year allows the Commission and the parties to assess the health of industrial sector as a whole after one year on the JRR and if an additional year would be in the public interest. In addition to the reduction of the pilot to one year, with the opportunity for a second year, the Commission determines that additional changes to the JRR are necessary for proper measurement and verification. First, the Company shall require the Customer to maintain an employment level of 90 percent of the its employees, with the number of employees determined by an average of its employment level over the twelve months prior to the filing of the Application and Agreement for the Job Retention Rider. The application shall state the specific number of employees and verify that this number represents 90 percent of the monthly average over the past twelve months. Second, the Customer shall submit in writing to DEC no later than March 1, and quarterly thereafter, a report verifying the employment level at the Customer's facility(s) receiving the Job Retention Rider credits. Third, if the Customer does not maintain the stated employee level, the Customer shall be removed from the tariff pursuant to the language in the proposed application and shall be required to refund the amount of benefits received under the JRR. DEC shall change the application language accordingly. The Commission has considered the arguments for expanding the JRR made by Commercial Group witnesses Chriss and Rosa, and concludes that expanding the JRR to other customer classes would place too large a burden on non-participants and would be unreasonable.

Furthermore, the Commission concludes that limiting the availability of the JRR to only industrial customers is not unreasonably discriminatory. Rather, it is based on a reasonable difference between customer classes, and the discount offered to participants under the JRR as compared to the amount of rider recovery on non-participants bears a reasonable proportion to the difference between the customer classes. See State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, 348 N.C. 452, 468, 500 S.E.2d 693, 704 (1998). Based on the evidence presented, the Commission finds that industrial customers' sales have been flat or declining since the recession, while residential and commercial sales are growing. Furthermore, a $0.003227 per kWh reduction in rates for participating industrials as compared to an increase in rates for the average retail customer of approximately $0.000539 per kWh per month under the JRR is proportionate to differences between these customer classes and reasonable given the economic and rate benefits of retaining industrial customers on DEC's system.

The Commission concludes that the JRR, with the modifications established in this Order, is in accordance with the requirements and guidelines the Commission previously established. In the JRT Order, the Commission directed utilities to "craft eligibility requirements that are narrowly tailored to meet the intended goals of maintaining jobs in the most economically efficient manner." Although the disputed phrase that allows for the eligibility for pipeline companies was included in the JRT Order as a possible example of eligibility criteria, the Commission is not persuaded that the eligibility criteria proposed by the Company is sufficiently narrow to ensure that the JRR will maintain jobs in the most efficient manner. Pipelines, which cannot relocate, are sufficiently different from other industrial customers and should be excluded from eligibility in the JRR. The disputed phrase "or the transportation or preservation of a raw material of a finished product" should be removed from the eligibility criteria.

The Commission further concludes that the customer attestations regarding certain eligibility requirements for the JRR, as modified by this order, are reasonable and adequate. Based upon the practical considerations of managing eligibility and how eligibility for certain rates is verified in other contexts, such as the opt-out process for DSM/EE rates, the Commission concludes that the Company's proposed method for verifying eligibility for the JRR is reasonable.

Commercial Group states that it does not take issue with the Commission's gradual approach to class revenue allocation, except if the Commission grants the proposed JRR. In that event, according to Commercial Group, the Commission should use any such reduction to move each customer class closer to its respective cost of service. The Commission does not agree with Commercial Group's position. The approval of the JRR does not eviscerate the principle of gradualism in reaching rate of return equilibrium among the customer classes. Further, the rate designs approved herein and the approval of the JRR will result in just and reasonable rates.

Finally, the Commission notes that the proposed JRR is a limited-term pilot, which will allow the Commission and the Company to follow the customers on the tariff and to consider whether the tariff meets its objectives of job retention and the related economic benefits. If it does not, then the JRR will not be continued beyond its one-year term. Except as modified by this order, the Commission finds that it is reasonable for DEC to implement JRR and JRRR as proposed in the Stipulation and Pirro Settlement Exhibit 1.

The Company, as well as ratepayers, benefit from the retention of industrial jobs, and the load related to the retention of the industrial jobs. In addition to the testimony in this case, this fact is further justified by the Company's indication in Docket No. E-100, Sub 73 that it was considering funding all or a portion of a JRT and provided comments on the necessary requirements for measurement and verification under the scenario of a fully Company-funded JRT. To achieve just and reasonable rates, if the pilot program is extended to a second year, it is appropriate for the Company to contribute to the JRR at the same level as year one. Therefore, the Company's recovery should be reduced by the amount of $4.5 million if the Commission determines in the rider proceeding that the JRR pilot program should be extended to a second year.

The Commission, therefore, concludes that the proposed JRR, as modified by this Order, is in the public interest, is not discriminatory and is consistent with the Commission's holding that "approval of a JRT is a matter of sound ratemaking policy to address the undisputed decline in industrial sales in North Carolina." Order Adopting Guidelines for Job Retention Tariffs in Docket No. E-100, Sub 73, at 22. If the JRR is extended an additional year and at the end of the second year the Company determines there is still a need for the JRR, nothing in this order prevents the Company for filing for a new JRR based upon the economic circumstances at that time.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 65-68

The evidence supporting these findings of fact and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the record in Docket No. E-7 Sub 1110, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

In Docket No. E-7, Sub 1103, DEC requested to defer its costs of complying with the Coal Ash Management Act (CAMA) and the EPA's Coal Combustion Residual Rule (CCR Rule, collectively CAMA) and notified the Commission that it had established an Asset Retirement Obligation (ARO).

In its March 15, 2017 comments in Docket No. E-7, Sub 1103, the Public Staff supported the Company's deferral request, provided that ratemaking treatment for the deferred amount would be determined in the next base rate case:

> In this particular case, the Public Staff believes that the non-capital costs and depreciation expense related to compliance with state and federal requirements cited in the Companies' petition generally satisfy the criteria for deferral for regulatory accounting (but not necessarily ratemaking) purposes. First, they are adequately extraordinary in both type of expenditure and in magnitude to justify consideration for deferral. Second, the effect of not deferring the expenses on the Companies' respective earned returns on common equity would be significant.

Initial Comments of the Public Staff, at p. 6.

In the present docket, DEC witness McManeus noted that the Company had petitioned in Docket Nos. E-2, Sub 1103, and E-7, Sub 1110, for approval to defer certain costs incurred to comply with environmental requirements for Coal Combustion Residuals (CCR or coal ash). Tr. Vol. 6, p. 239. While various parties opposed recovery in rates of some of the coal ash costs, that is a separate issue from the deferral request. The deferral request was generally unopposed, and the Commission finds and concludes that deferral in a regulatory asset for previously incurred coal ash environmental costs is consistent with the Commission's criteria for deferrals and reasonable in the circumstances of this case.

In the present docket, Public Staff witness Maness indicated that the Public Staff continues to believe that prudently incurred CCR expenditures should be allowed to be deferred for regulatory accounting purposes. Witness Maness made several adjustments and with regard to the addition of a return on deferred coal ash expenditures from December 2017 through April 2018, DEC agreed with this adjustment (Tr. Vol. 6, p. 314), and it was not opposed by other witnesses.

The Commission notes that new rates will not be effective by May 1, 2018, as might have been expected at the time of the filing of witness Maness' testimony; therefore, the Commission finds it appropriate and reasonable to extend the accrual of this return until the effective date of rates approved in this proceeding. Based on the foregoing, the Commission finds and concludes that a return based on the net-of-tax overall weighted cost of capital authorized in DEC's last general rate case should be added to the amount of deferred coal ash costs are approved in this Order for recovery in rates, and that the return should be applied through the effective date of the rates approved in this proceeding.

Additionally, as recommended by the Public Staff, the Commission concludes that use of the 2018 federal income tax rate of 21% is appropriate to calculate the 2018 portion of the carrying costs. With respect to Public Staff witness Maness' adjustment regarding mid-month cash-flow convention, DEC witness McManeus accepted this adjustment (Tr. Vol. 6, p. 314), and no other witness opposed it. The Commission finds and concludes that the mid-month convention for calculation of the return is reasonable and appropriate. Additionally, as recommended by the Public Staff, the Commission concludes that compounding of the carrying costs should take place at the beginning, rather than the end, of January of each year.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 69-72

The evidence supporting these findings and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony of the public witnesses, and the testimony and exhibits of the following expert witnesses: DEC witnesses Fountain, McManeus, Kerin, Wells, Wright, De May, Hager, and Doss; Public Staff witnesses Junis, Garrett, Moore, Lucas, Boswell, and Maness; AGO witness Wittliff; CUCA witness O'Donnell; and Sierra Club witness Quarles.

The public witness testimony and expert witness testimony and exhibits regarding DEC's CCR costs are voluminous. The Commission has carefully considered all of the evidence and the record as a whole. However, the Commission has not attempted to recount every statement of every witnesses. Rather, the following is a complete summary of the evidence.

Likewise, the Commission has read and fully considered the parties' post-hearing briefs. However, the Commission has not in this order expressly addressed every contention advanced or authority cited in the briefs.

Based upon the evidence addressed below and in the exercise of its expert judgment and discretion, the Commission determines that a management penalty of approximately $70 million should be assessed for DEC's mismanagement of its CCR activities undertaken through the end of the test year as extended for reasons set forth hereafter.

Coal-fired power plants have played a predominant role in electricity generation by DEC throughout its history, and the Company is dependent upon coal-fired generation today. With coal-fired generation comes a by-product – coal ash, also known as coal combustion residuals, or CCRs. At least since the 1950s, standard industry practice, particularly in the Southeastern United States, has been reliance on coal ash basins. Such basins were constructed and used at all of the Company's coal-fired generating units.

The United States Environmental Protection Agency (EPA) has studied CCRs and their proper management and handling since the 1980s, but the agency only began moving forward on comprehensive regulation of CCRs less than ten years ago. In 2010, the EPA issued proposed rules regarding CCRs. EPA's final rule – the Coal Combustion Residuals Rule (CCR Rule) – was promulgated on April 17, 2015. North Carolina also enacted specific statutory requirements for coal ash management in CAMA, which became effective in 2014 and was amended in 2016. The CCR Rule and CAMA introduced new requirements for the management of coal ash. DEC, of course, must comply with these new requirements, which mandate closure of the Company's coal ash basins. Mandated closure triggers Generally Accepted Accounting Principles (GAAP) provisions relating to the retirement of long-lived tangible assets, and specifically triggers the requirement that the Company account for compliance costs through ARO accounting. The Company, as required by GAAP, established an ARO with respect to its coal ash basins, and, in accordance with the Commission's orders in Docket No. E-7, Sub 723, deferred the impacts of its GAAP-mandated ARO accounting. The Company now seeks recovery of the coal ash basin closure costs incurred to date in connection with CCR Rule and/or CAMA compliance, along with such costs it anticipates will be incurred annually on an ongoing basis. The Company's proposal has three component parts:

- First, DEC seeks recovery of the actual coal ash basin closure costs it incurred from January 1, 2015 through December 31, 2017. On a North Carolina retail jurisdiction basis, these costs amount to $566.8 million.[1] McManeus Rebuttal Ex. 3, pp. 36-37. The Company proposes further that, rather than recovering 100% of these already incurred costs immediately, it recover them over a five-year amortization period, and it seeks a return on the unamortized balance.
- Second, DEC seeks to recover on an ongoing basis $201.3 million per year in annual coal ash basin closure spend. This amount is based upon the NC retail jurisdiction portion of the test year (2016) coal ash basin closure expense incurred by the Company.
- Third, DEC seeks permission to establish a regulatory asset/liability and defer to this account the NC retail portion of annual costs that are over or under the costs established in connection with the Company's request that it be permitted to recover in rates on an ongoing basis its actual test year coal ash basin closure costs – i.e., the amount over or under $201.3 million, if the Company's proposal as detailed above is approved by the Commission. In addition, the costs incurred from January 1, 2018 through the date new rates set in this proceeding are effective would also be deferred to this account. The deferred amounts (including a return) would be brought into rates and recovered through future rate cases.

The Commission, as it has in prior rate orders, provides a review of the applicable legal principles, to provide a framework for the application of those principles to the facts of this particular case. See, e.g., 2013 DEC Rate Order, pp. 23-28 (in Duke Energy Carolinas 2013 Rate Case, Commission provided an extensive review of the "governing principles" regarding rate of return). For purposes of assessing the Company's coal ash basin closure cost recovery proposal, the applicable principles include (1) the general cost recovery framework and the role of the revenue requirement in that framework; (2) principles underlying "reasonable and prudent" costs;

[1] This amount excludes any fines, penalties and other unrecoverable costs incurred by the Company. See Tr. Vol. 6, p. 259.

(3) principles underlying the concept of "used and useful," and (4) a discussion of the burden of proof, and, in particular, presumptions and the distinction between the burden of production (borne by Intervenors) and the ultimate burden of persuasion (borne by the Company).

In the recently-decided DEP rate case (Docket No. E-2, Sub 1142, the 2018 DEP Rate Case, or 2018 DEP Case), the Commission's decision summarized cost recovery based upon these principles, and found that for cost recovery the utility must prove that the costs it seeks to recover are "(1) 'known and measurable'; (2) 'reasonable and prudent'; and (3) 'used and useful' in the provision of service to customers." 2018 DEP Rate Order, p. 143. The same standard applies in this case.

The arguments raised by Intervenors in this docket challenge the inclusion of the Company's coal ash basin closure costs in rates because the costs are not "reasonable and prudent" and "used and useful," or on the theory that cost recovery should be shared by both the shareholders and ratepayers.

Summary of the Evidence

A. Company Direct Case Overview and Costs Sought for Recovery

In his direct testimony, Company witness Fountain testified that DEC is requesting recovery of ash basin closure compliance costs incurred in the period from January 1, 2015 through November 30, 2017. Witness Fountain explained that the Company has removed costs related to its response to the Dan River release and is not requesting their recovery for them. Tr. Vol. 6, p. 174. Witness Fountain also testified on direct that, based on actual coal ash expenses incurred during the 2016 test year, DEC is seeking recovery of ongoing ash basin closure compliance spend of $201 million per year, with any difference from future spend being deferred until a future base rate case. He stated that including this revenue requirement will provide a measure of predictability to customers of future coal ash expense rate drivers. Id. at 174.

Company witness McManeus testified that Adjustment No. 18 to the Company's operating revenues and expenses amortizes the actual deferred costs incurred through December 31, 2017, in connection with compliance with federal and state environmental requirements related to CCRs, pursuant to DEC's petition in Docket Nos. E-2, Sub 1103 and E-7, Sub 1110 for authority to defer such costs in a regulatory asset account, over a five-year period. She explained that while the costs to comply with CAMA and the CCR Rule are largely duplicative, the Company has determined a small portion of the costs to be specific to CAMA, unique to North Carolina and appropriate for direct assignment to North Carolina. She stated that in the deferral calculation, for CAMA-specific costs, the adjustment separates out the portion allocable to the wholesale jurisdiction and directly assigns the retail portion to North Carolina retail. She stated that these costs were based on actuals at the end of the test period, updated through November 30, 2017.[1] The Company proposes to defer these costs over a five-year period and to earn a net of tax return on the unamortized balance. Witness McManeus testified that the expected deferred balance, based on total system spend on

[1] These costs were later updated to actual costs through December 31, 2017, and the deferred balance including return computed as of April 30, 2018. McManeus Rebuttal Ex. 3, pp. 36-37.

these costs during this period, plus applying allocation factors and incorporating the return on the deferred costs, is $524.0 million.[1] Witness McManeus clarified the Company seeks no recovery for fines, penalties, or costs of which DEC has agreed to forego in the deferral. Tr. Vol. 6, pp. 259-60, 279-80, 288-89, 297, 343.

Witness McManeus testified that Adjustment 19 increases O&M to reflect the expected ongoing annual level of expenses DEC will incur in connection with coal ash compliance costs represents the amount in ongoing annual coal ash basin closure expense (sometimes referred to in this Order as "ongoing compliance costs"). She explained that this number – $201.3 million on a North Carolina retail basis – is based upon actual test year (2016) spend, and stated that the Company is also requesting permission to establish a regulatory asset/liability and defer to this account the North Carolina retail portion of annual costs over or under the amount established in this proceeding. She explained that this will ensure that the Company only recovers from customers its actual level of spending related to coal ash. She also clarified that no fines, penalties, or costs of which DEC has agreed to forego recovery are included in this adjustment. Tr. Vol. 6, pp. 260-61, 279-80, 288-89.

B. Company Direct Case: Coal Ash Overview

Company witness Kerin described his management role with the Ash Basin Strategic Action Team (ABSAT), the umbrella organization created for Duke Energy companies to address the laws, regulations, and orders concerning the management of CCRs. Witness Kerin discussed how, during his work on the ABSAT team, he spent approximately 3,000 hours working exclusively on CCR issues, familiarizing himself with state and federal regulations dealing with CCR and historical industry practices and standards used to comply with such regulations. He described how he interviewed legacy employees who worked at, and with, coal combustion generating units and CCR handling sites, and reviewed historical company documents dealing with those facilities and sites in order to gain an understanding of how CCR handling standards inside and outside of the Company developed over time. Witness Kerin also described how he toured and inspected every CCR basin in Duke Energy's North and South Carolina jurisdictions, as well as CCR sites at Duke's Midwest sites, Dominion, AEP, and TVA. He detailed how he developed CCR evaluations for Duke Energy's CCR sites, and an industry peer group to discuss CCR issues generally, which continues to meet semi-annually. Witness Kerin concluded that during his time on the ABSAT team, he gained an understanding and knowledge of coal ash management practices at utilities across the country. Tr. Vol. 14, pp. 96-97.

Witness Kerin provided a detailed discussion of DEC's coal ash management history and practices and the new obligations imposed on the Company by the CCR Rule and CAMA. He explained that CCRs are by-products produced from the electricity production process lifecycle – the burning of coal – at coal-fired generation plants and include fly ash, bottom ash, boiler slag, and flue gas desulfurization (FGD) material. He stated that environmental regulations related to CCR management have evolved significantly over time, affecting how the Company has operated its coal-fired plants in compliance with those obligations. He maintained that at each step in the

[1] This amount has been adjusted to $566.8 million based on the estimated deferral balance at April 30, 2018. McManeus Rebuttal Ex. 3, pp. 36-37.

environmental regulatory evolution process, DEC was in line with industry standards and maintained that DEC reasonably and prudently managed CCRs and its coal ash basins. He explained that since its last rate case, DEC has become subject to both federal and state regulations that require it to take significant action to close its ash basins. Tr. Vol. 14, pp. 99-112.

Witness Kerin testified that since the early 1900s, DEC has disposed of CCRs in compliance with then current regulations and industry practices. Until the 1950s, CCRs were either emitted through, in the case of fly ash, smokestacks or, in the case of bottom ash, manually removed the ash from boilers and stored it in landfills. Since that time, the industry transitioned to a water sluice to remove ash from boilers, and to clean the electrostatic precipitators, preventing ash from being emitted through the smokestacks. This effluent, as well as FGD blowdown, was then diverted to ash basins, of which DEC has 17 in the Carolinas. In other words, in many cases, ash basins were actually created or relied upon to effectuate prior environmental regulations. In the mid-1970s, the enactment of the Clean Air Act and its subsequent amendment in the 1990s required electric utilities to capture more CCRs through the use of electrostatic precipitators (ESP) or bag houses and FGD blowdown. Tr. Vol. 14, pp. 99-112.

Witness Kerin provided a detailed history of coal ash regulation. He testified that the Clean Water Act of 1972 and the subsequent creation of the National Pollutant Discharge Elimination System (NPDES) permitting system, made wet ash handling and ash basins the primary lawful and effective way to meet CCR needs and environmental requirements from 1974 until 2015. Tr. Vol. 14, pp. 100, 106-09.

Witness Kerin testified that, in June 2010, the EPA proposed national minimum criteria to regulate the disposal of CCRs and the operation and closure of active CCR landfills and existing and inactive CCR surface impoundments. He stated that, approximately five years later in April 2015, EPA published the final CCR Rule in the Federal Register. He explained that the CCR Rule established national minimum criteria for CCR landfills and surface impoundments, which result in different impacts at each CCR unit, depending on site-specific factors, and testified to the exact nature of those criteria. He stated that the CCR Rule also contains requirements for how and when CCR basins must be closed, and that it provides for closure either by cap-in-place or removal of the ash. He noted that as stated in the CCR Rule, the EPA considers CCRs to be a non-hazardous solid waste. In 2014, North Carolina enacted CAMA, which requires that all ash basins in the State be closed, either through excavation or via the cap-in-place method. He explained further that CAMA requires closure of all ash basins in North Carolina, with the closure option (excavate or cap-in-place) and deadline driven by a prioritization risk ranking classification process. Witness Kerin noted that, in many respects, CAMA mirrors the federal CCR Rule. He stated that all of DEC's ash basins must be closed under one or both of these programs. Tr. Vol. 14, pp. 100, 115-26.

He also stated that the Company has begun the process of closing, or submitting plans to close, its ash basins in accordance with the program with the most limiting requirements. Tr. Vol. 14, p. 100. Witness Kerin also testified that coal-powered electric generation has since ceased at four of the eight coal-fired DEC generating facilities with ash basins, including the Dan River, Buck, Riverbend, and W.S. Lee plants. Id. at 103.

Witness Kerin also noted that in addition to the CCR Rule and CAMA, DEC is also subject to other CCR-related obligations that result from state environmental regulatory oversight under existing rules and regulations. For DEC, in South Carolina, there is one Consent Agreement with the South Carolina Department of Health and Environment (SCDHEC) applicable to ash management at the W.S. Lee plant. The W.S. Lee Consent Agreement, between DEC and SCDHEC, requires ash excavation of the Inactive Ash Basin, the Ash Fill Area, and any other areas where ash may have potentially migrated from these sites. Tr. Vol. 14, p. 127.

Witness Kerin testified that the CCR Compliance Requirements—CAMA, the CCR Rule, and other consent and/or settlement agreements and orders concerning CCR management and disposal—represent new regulatory requirements that have significantly changed the operation and life cycle of the on-site ash basins and landfills. Id. at 115. He noted that there is a great deal of duplication and interaction between federal rule, state law and agency action and that many of the actions Duke Energy will take will serve multiple compliance purposes. He explained that many actions and draft rules applicable to many utilities, not just Duke Energy, were already being developed prior to 2014, and that the Company is now in another wave of evolution in environmental regulation pertaining to ash. He stated that in response to these new requirements addressing CCR disposal activities, the Company is adding dry fly ash, bottom ash, and FGD blowdown handling systems to operating coal-fired plants that are not already so equipped. He also stated that the Company is modifying all active and decommissioned plants to divert storm water and low-volume wastewater away from the basins. He testified that, accordingly, the Company is requesting recovery of the incremental compliance costs related to coal ash pond closures incurred starting in 2015 through November 30, 2017, and recovery of ongoing compliance costs. He maintained that both these incurred and ongoing compliance costs are reasonable, prudent, and cost effective given the individual facts and circumstances at each power plant and ash basin site at issue. He maintained further that each of the Company's historical and ongoing CCR compliance costs is reasonable, prudent, and cost effective given the individual facts and circumstances at each power plant and ash basin site at issue. Tr. Vol. 14, pp. 100-01.

Witness Kerin stated that ash removal has been initiated at several DEC stations, including the Dan River and Riverbend Plants. He stated that excavation plans were developed to systematically prepare for executing this work, including the identification of any necessary permits and approvals. These excavation plans were submitted to the applicable state regulatory body, SCDHEC or DEQ, prior to beginning ash excavations. As the CCR Rule and CAMA lead to ash basin closure, preparations are required to transition the coal-fired generating sites for this outcome. Operating coal-fired power plants in the Carolinas require plant modifications to fully transition to dry ash handling in order to cease sluice flow to the ash basins. All coal-fired power plants, even those retired, require some level of modification to cease all flows to the ash basins, such as storm water or low volume waste water, and may require construction of a new retention pond. These modification activities are planned and are now being executed. Tr. Vol. 14, p. 132.

Witness Kerin described the closure plans and site analysis and removal plans developed by Duke Energy to physically close the ash basins, noting that these plans are technically informed by the structural stability of the impoundments, the potential for adverse impacts from external events such as 100-year floods, the groundwater and/or surface water impacts identified in the Closure Study Analysis, and the groundwater corrective actions required in the Corrective Action

Plans. Ash basins can be closed by excavation, with the ash permanently stored in a CCR landfill or used in a beneficial way such as a structural fill or for cementitious purposes. Ash basins can also be closed by capping the CCR in place. Tr. Vol. 14, pp. 132-33.

Witness Kerin also maintained that the Company's CAMA closure plans will meet the national standards set forth by the CCR Rule as well as the more specific requirements determined by the North Carolina Department of Environmental Quality (DEQ) under the CAMA regulatory process. He explained that the state-mandated closure plans are reviewed and approved by SCDHEC in South Carolina and DEQ in North Carolina. During this review and approval process, these state regulatory agencies could impose additional restrictions, limitations, requirements, and/or actions to close the ash basins. Other specific compliance plans will be developed and implemented to meet the various requirements and timelines of CAMA and the CCR Rule, such as the fugitive dust control plans, which were required under Section 257.80 of the CCR Rule by October 19, 2015. As a second example, run-on and run-off control system plans were developed and implemented by October 19, 2016, for CCR landfills pursuant to Section 257.81 of the CCR Rule. Compliance plans will continue to be developed and implemented as required by the CCR Rule and CAMA. Tr. Vol. 14, p. 133.

Company witness Kerin testified that in Exhibits 10 and 11 to his testimony, he broke the ash pond closure costs already incurred or expected to be incurred prior to November 30, 2017, down into their core components and described the plants to which these costs apply. In detailing these costs, he also provided narrative summaries as to why, in his view, these costs were incurred and why the compliance actions which led to those costs were the most reasonable and cost-effective options given the applicable facts and circumstances. He maintained that these exhibits, coupled with the balance of his testimony and exhibits, demonstrate that these costs are reasonable and prudent. Tr. Vol. 14, p. 135.

Company witness Kerin maintained that DEC's historical handling of CCRs was reasonable, prudent, and consistent with industry standards over time. This demonstrates that nothing that DEC has done historically is causing the Company to incur any unjustified costs today to comply with post-2015 CCR regulations. Tr. Vol. 14, p. 135. Company witness Kerin explained that, in the preamble to the CCR Rule, EPA details that in 2012 alone, over 470 coal-fired electric generating facilities burned over 800 million tons of coal, generating approximately 110 million tons of CCRs in 47 states and Puerto Rico. In 2012, approximately 40% of the CCRs generated were beneficially used, with the remaining 60% disposed in CCR surface impoundments. Of that 60%, approximately 80% was stored in on-site basins and landfills. Across the United States, CCR disposal currently occurs at over 310 active on-site landfills, averaging over 120 acres in size with an average depth of 40 feet, and at over 375 active on-site surface impoundments. Stated differently, according to witness Kerin, the Company is re-using (selling) and storing CCRs in the same manner and at approximately the same percentages as the coal-fired utility industry's national averages. Duke Energy's practices have been and continue to be consistent with those of the industry. Similar to the industry, DEC has on-site CCR landfills that are actively receiving production fly ash, and some bottom ash, at specific coal-fired generating sites, including the Allen, Belews Creek, Cliffside, and Marshall Plants in the Carolinas. Also similar to the industry, DEC has active ash basins still receiving bottom ash, and some fly ash, at specific coal-fired generating sites, including the Allen, Belews Creek, Cliffside, and Marshall Plants in the

Carolinas. Witness Kerin maintained that the ash handling practices for ash basins and ash landfills in the Carolinas are consistent with the applicable regulatory requirements that were in effect during the history of these CCR units. Tr. Vol. 14, pp. 113-14.

Witness Kerin also maintained that DEC's CCR storage and handling practices are consistent with the practices of other Duke Energy affiliates and Duke Energy peer utilities. He explained that the Company's CCR storage and handling practices are consistent across the Duke Energy fleet, including coal generation located in Florida and in the Midwest. Duke Energy as it currently exists today has been formed over the years through the mergers of several utilities with independently operated coal fired generation, including the Cinergy Corporation in 2006 and Progress Energy, Inc. in 2012. Indeed, going further back in time, Progress Energy, Inc. was created in 2000 from the merger of legacy utilities CP&L and Florida Power Corporation (FPC). Similarly, Cinergy Corporation was created in 1994 by the merger of legacy utilities Public Service Indiana (PSI) and Cincinnati Gas & Electric Company (CG&E). Yet, the historical and current CCR handling and use of CCR basins is consistent across all of these legacy companies that make up Duke Energy Corporation today, and consistent with the industry. Tr. Vol. 14, p. 114.

At the hearing, in response to questions from counsel for the Sierra Club regarding reports on ash disposal from the 1970s and 1980s, witness Kerin clarified that DEC did not build any new basins after 1982, when the last basin was constructed at Buck, and that any other disposal areas constructed by the Company would have been undertaken pursuant to permit by the DEQ or its predecessor. Tr. Vol. 14, pp. 180-84. He also testified that, in his opinion, there would not be increased cost associated with the schedule of activities contained in the draft Special Order by Consent (SOC) resolving a DEQ Notice of Violation with regard to the Allen, Marshall, and Cliffside plants that would not otherwise have been incurred, and clarified that cap-in-place costs are based on acreage size, not volume of ash in the basin. Id. at 213-18.

In his direct testimony, Company witness Wright noted that coal ash use and disposal has been studied by the EPA since the mid-1980s. After several studies and some limited regulatory standards, on May 22, 2000, the EPA determined the need to regulate coal combustion wastes under Subtitle D of the Resource Conservation and Recovery Act (RCRA). He noted that these types of expenses have been routinely recovered as a cost of service and included in rate cases including the reasonable costs associated with operating, maintaining and upgrading environmental equipment. The cost recovery for these rate-based environmental costs also usually included a return. Tr. Vol. 12, pp. 130-31.

C. Company Direct: Cost Recovery Overview

Witness Wright also testified that in part as a response to an accident at a surface impoundment at Tennessee Valley Authority's (TVA) Kingston Fossil Plant in Harriman, Tennessee, the EPA published in the Federal Register proposed new coal ash disposal regulations for CCRs. The proposed regulations specifically referenced the TVA incident as a major reason for the proposed rule, and discussed several other coal ash incidents that led to the promulgation of the rule. Witness Wright maintained that, because the EPA's proposed rule's publication date precedes the February 2, 2014 coal ash release accident at the Dan River Steam Station (Dan River), the Dan River accident was not mentioned in the EPA's proposed rule, nor could it have been, as a reason for establishing the rule. He also noted that EPA's finalized CCR Rule, signed on December 19, 2014 and published in the Federal Register (FR) on April 17, 2015, did reference the Dan River accident, but it did not indicate that the accident modified the proposed rule. Tr. Vol. 12, pp. 131-32.

Witness Wright further explained that in August 2014, after the EPA's proposed coal ash regulations were published but prior to their finalization, the State of North Carolina adopted CAMA. He noted that while EPA and CAMA rules are similar in many respects, "largely duplicative," DEC must ensure that its coal ash disposal methods meet the standards established in both regulations as well as any other state agency requirements. Tr. Vol. 12, p. 132.

Witness Wright maintained that recoverable costs, as they relate to electric utility expenditures in North Carolina, are costs that are reasonable and that are prudently incurred in the provision of safe, reliable electric service to a utility's customers. He argued that N.C. Gen. Stat. § 62-133(b) embodies this principle. He maintained that because environmental compliance costs are a necessary cost of providing electric service, these types of costs – and a return on those costs if deferred over time – are recoverable in rates. He also maintained that environmental compliance costs are similar to other costs that a utility might spend in producing and delivering power. He asserted that the Company incurs costs in compliance with environmental laws and regulations, similar to other costs necessary for the generation of electric power, and that these coal ash disposal costs are like nuclear decommissioning costs or coal plant retirement costs which have long been deemed recoverable for utilities across the country, including DEC. Tr. Vol. 12, p. 123.

Witness Wright noted that the Commission has allowed the recovery of costs related to environmental expenditures. Citing to witness Kerin's lengthy discussion of the numerous investments the Company has made over time in compliance with historical coal ash and other environmental regulations, he asserted that in his experience these types of costs, including the reasonable costs associated with operating, maintaining and upgrading environmental equipment, plus a return, have been routinely recovered as a cost of service through general rate cases, whether as capital or ongoing operation and maintenance expense or some combination thereof. Tr. Vol. 12, pp. 127-29.

Witness Wright testified further that utilities are not allowed to recover environmental fines or penalties, or costs incurred from the actions causing such penalties. He stated his understanding that none have been requested in this case. He also asserted that it is important, however, to make sure that the costs underlying or directly causing such fines or penalties be separated from prudently incurred, ongoing costs. For example, he offered, if a generating plant received a fine, that fine should not be recoverable. The fact that a fine was given, however, does not mean that the ongoing, prudently-incurred costs necessary to produce generation should be disallowed. Tr. Vol.12, p. 130.

Witness Wright further asserted that the new federal coal ash standards did not result from the Dan River spill. He noted that the final rule only mentions the Dan River accident, and that there is no clear evidence in the final rule that the Dan River accident changed or modified the EPA's proposed rule. He asserted that both the proposed rule and the final rule addressed the need for imposing corrective action at inactive facilities, and asserted that in promulgating the

CCR Rule, the EPA cited hundreds of potential risks or incidents with ash ponds similar to Dan River that, in part, led to the adoption of the Rule. Based on this analysis along with the timing of the CCR Rule, he opined that the Dan River accident did not change the CCR regulations, although it probably added support for the EPA's proposals. Tr. Vol. 12, pp. 132-34.

Witness Wright also maintained that, in terms of timing, the new state CAMA coal ash standards did result from the Dan River spill, but in terms of the substance of the standards adopted there is not necessarily a connection. He opined that the Dan River spill helped prompt the North Carolina General Assembly to examine the State's and national coal ash disposal policies and regulations, and that out of that legislative investigation came CAMA. He noted that some four years prior to Dan River, the EPA had proposed and was close to finalizing its new CCR regulations, which in his opinion helped inform the State's legislative leaders regarding the language contained in CAMA. He noted that the proposed CCR regulation also strongly encouraged the states to adopt at least the federal minimum criteria in their solid waste management plans. Therefore, he concluded, that the North Carolina Legislature and/or the State's DEQ would likely have taken steps to adopt coal ash regulations shortly after the CCR Rule was finalized in 2015. He concluded that the timing of CAMA was influenced by the Dan River accident, but also expressed his belief that, even without the Dan River accident, the State would likely have adopted some new coal ash disposal standards similar to CAMA in the 2015 timeframe in response to the CCR rules. He stated that, regardless, the Company must comply with both the federal and state coal ash disposal standards. Tr. Vol. 12, pp. 134-36.

In his direct testimony, Company witness Wright testified that, in his opinion, the coal ash disposal costs that DEC seeks to recover in this case are "used and useful" utility cost. Tr. Vol. 12, p. 144. He explained that DEC's coal ash disposal sites have always been used and useful as part of the coal-fired generation production process. He noted that N.C. Gen. Stat. § 62-133(b)(1) provides that, in setting utility rates, the Commission must "ascertain the reasonable original cost of the public utility's property used and useful, or to be used and useful within a reasonable time after the test period, in providing the service rendered to the public within the State, minus accumulated depreciation, and plus the reasonable cost of the investment in construction work in progress." Id. He testified that, therefore, to be recoverable and/or included in rate base, the cost must be both reasonable and incurred for property that is used and useful in providing service to customers. He stated that the Company has historically spent dollars in order to comply with the coal ash disposal regulations in effect at the time, and these dollars were a necessary expenditure related to used and useful utility costs made in the provision of electric service at the time. The Company was, and continues to be, obligated to meet the needs of its customers. This obligation to serve requires the disposal of coal ash subject to the disposal standards at the time, thereby rendering the disposal sites for this coal ash, for which costs DEC seeks recovery in this case, "used and useful" in providing electric service. Id. at 144-45. He stated that this is supported by the Commission's conclusions in the 2016 Dominion rate case, where the Commission determined that because current CCR repositories are and have served their purpose of storing CCRs for many years, they have been used and useful for ratepayers, and that such storage facilities will continue to be used and useful until the CCRs are moved to a permanent repository, or they are capped and closed. Id. at 145-46.

Witness Wright also noted with respect to the Commission's Order Approving Rate Increase and Cost Deferrals and Revising PJM Regulatory Conditions in Docket No. E-22, Sub 532 (Dec. 22, 2016) (2016 DNCP Rate Order) that, in that case, the Commission addressed the exact issue of the recovery of coal ash disposal costs that is at issue in this proceeding. In addition to the decision that prior coal ash disposal assets were used and useful, he noted that in that order the Commission and Public Staff concluded that Dominion's historical response to coal ash disposal was consistent with industry practice at the time and that these costs were reasonable and prudent. Second, they found that Dominion's test year coal ash disposal expenses incurred in compliance with the newer coal ash disposal regulations were likewise reasonable and prudent. Finally, he noted that, similar to what DEC is requesting in this rate case, the 2016 DNCP Rate Order also allows Dominion to establish an ARO to defer additional coal ash disposal cost and for the recovery of those costs to be adjudicated in a future proceeding. Tr. Vol. 12, pp. 146-47.

D. The Positions of Intervenor Parties other than the Public Staff

AGO witness Wittliff maintained that the Dan River ash release was largely responsible for the development of CAMA in its present form, which he said accelerated remediation and closures and narrowed the field of removal and closure options. Tr. Vol. 11, pp. 239, 248-50, 272. He claimed that the plea agreements into which the Company has entered evidence harm to the environment caused by DEC's criminal negligence. Id. at 239-41, 265-67, 272-73. He also claimed that the Company's actions and inactions resulted in environmental harm and the incurrence of compliance costs that could have been significantly lower or possibly even avoided. Id. at 274-75. He asserted that, by not building new lined surface impoundments when it was "obvious" that additional impoundments were needed and would better protect the environment, the Company delayed and avoided potential exposure to requirements for more rigorous environmental controls on the new impoundments. Id. at 255. He questioned the Company's diligence with respect to managing dam safety, contended that the Company did not comply with the requirements of its ash basin permits at Dan River and Riverbend, and asserted issues of vegetation control and stability of impoundments at other facilities. Id. at 255-63, 273-74. He also claimed that the Company's 10-K filings with the Securities and Exchange Commission (SEC) show Duke Energy's awareness of trends in coal ash management and regulation towards lined impoundments. Id. at 236-38. Witness Wittliff further questioned Company witness Kerin's expertise with regard to coal ash issues and claimed that the Company's coal ash handling practices were not consistent with industry. Id. at 268-69.

At the hearing, in response to questions by counsel for the Company, witness Wittliff admitted that, while his testimony stated that he would support a Commission finding that the coal ash costs incurred by DEC were unreasonable and imprudent, his actual position is that the Company should be able to recover its costs to comply with the CCR Rule, but nothing more. Tr. Vol. 11, pp. 279-81. However, in its post hearing brief the AGO, on whose behalf witness Wittliff testified, maintained that all of DEC's 2015-2017 CCR remediation costs should be disallowed. Witness Wittliff stated that costs incurred by the Company to comply with the CCR Rule are reasonable and prudent. Id. at 282-83. He admitted that he did not identify any specific costs that could have been lower or should be disallowed. Id. at pp. 287-89. In response to questions regarding environmental compliance issues at electric power stations at which he had worked over the course of his career, witness Wittliff testified that he was not in a position at those times to say what those companies should or should not have done with respect to environmental compliance, but that he is in such a position now with respect to DEC, to say what should have happened with the Company's previous coal ash management. Tr. Vol. 11, p. 289 – Tr. Vol. 12, pp. 13-24.

CUCA witness O'Donnell opined that DEC should only recover costs to comply with the CCR Rule, not any costs under CAMA that exceed CCR Rule compliance costs, based on his contention that Duke Energy caused CAMA. Tr. Vol. 18, pp. 59-60. Witness O'Donnell purported to compare the DEC coal ash ARO to what he termed similar coal ash AROs of utilities across the United States. He concluded that the Company's ARO coal ash costs are among the highest in the nation, and contended that the only discernable difference between the Duke Utilities and the other utilities in his comparison was CAMA, which he asserted was prompted by the Dan River spill. He stated that DEC did not provide a similar financial analysis for this case. Id. at 56, 61-66. He asserted that there is no evidence to suggest that Duke's coal ash situation is significantly different from that of utilities across the country or from that of utilities in neighboring states. He claimed the Company failed to provide any evidence to counter his argument that its mismanagement led to excessive costs associated with its coal ash cleanup, and that because the Company chose not to dissect his analysis "bit by bit," that gives his evidence more credence. Id. at 66.

Sierra Club witness Quarles evaluated the methods DEC has proposed to close existing coal ash ponds at the Allen and Marshall plants and opined as to environmental conditions that may be associated with capping those ponds in place. He asserted that he evaluated site conditions at each location and the likelihood that DEC will be able to meet closure performance standards in the CCR Rule if it opts for cap-in-place closure. He also asserted that continued storage of coal ash at Allen and Marshall poses significant environmental risks. He stated that the coal-fired power plant industry recognized in at least the mid-1970s that disposal of CCRs into unlined disposal units and within close proximity to groundwater was risky, and that construction of unlined disposal units after that time was unreasonable. He claimed it would have been consistent with industry practice at the time for DEC to close and remediate leaking impoundments and construct new, lined dry landfills. He asserted that the Company built new unlined disposal areas at Allen and Marshall, and that lined landfills and surface impoundments were commonplace and more cost effective than building unlined surface impoundments since the mid-1970s. Tr. Vol. 6, pp. 19-118, 120-22.

Witness Quarles stated that the unlined basins at these plants were constructed over named and unnamed stream valleys, with wastes submerged in groundwater, and groundwater flows into those basins from topographically higher elevations and will come in contact with submerged coal ash. He also stated that there are documented impacts to groundwater at these basins and that a cap will not prevent lateral inflow of groundwater from adjacent areas. He concluded that closure in place at these basins would allow continued contamination of downgradient groundwater and violate the technical standards of the CCR Rule, and that removal of coal ash from the Company's ash basins would reduce the concentrations and extent of this contamination. Lastly, witness Quarles stated that DEC's plan for closure-in-place is well documented by the coal power trade industry association as an inappropriate groundwater corrective action where CCRs are submerged in groundwater like at Allen and Marshall. Tr. Vol. 6, pp. 19-118, 122-24.

At the hearing, Witness Quarles did not dispute on cross examination by Company counsel that the 1988 Report to Congress stated that only about 25% of all facilities had liners to reduce offsite mitigation of leachate, that only 40% of generating units built since 1975 had liners, that only 15% had leachate collection systems, only one-third had groundwater monitoring systems and that such systems were more common at newer facilities, that coal combustion waste streams generally do not exhibit hazardous characteristics, and that EPA's tentative conclusion was that current waste management practices appear to be adequate for protecting human health and the environment. Witness Quarles also confirmed that he did not conduct a site-by-site engineering analysis of the cost to the Company to close and remediate leaking impoundments and construct new, lined dry landfills. Tr. Vol. 6, pp. 143-45. In response to questions by the Commission he admitted that he has not raised the concerns he raised in this proceeding regarding cap-in-place at Allen and Marshall with DEQ. Tr. Vol. 6, pp. 149-50.

In its post-hearing Brief, the AGO contends that ratepayers should not be forced to cover costs caused by DEC's historic imprudence in managing its coal ash basins. The AGO argues that the Commission needs to consider several factors when determining whether the costs incurred are recoverable in rates. The AGO outlines them as follows: 1- The first is DEC's history of imprudence; 2- DEC's costs must be reviewed in detail to evaluate whether and to what extent they are for property that is "used and useful" and are recoverable in ratebase; 3- DEC has insurance to cover a large portion of the coal ash remediation costs it seeks from ratepayers, and these insurance proceeds should be taken into account; 4- DEC's request for cost recovery relies on a petition for an accounting order allowing deferral of the costs that is untimely, unreasonable, and unjustified as a basis for retroactive recovery of expenditures that DEC incurred in 2015 and 2016; and 5- DEC's claim that it is "entitled" to the recovery of coal ash costs from prior periods if it proves the costs are "known and measureable," "reasonable and prudent," and "used and useful" is not consistent with the statutory ratemaking regime, in which rates are established and become effective prospectively in order to allow—but not guarantee—the opportunity for cost recovery, and the rates are presumed to be just and reasonable until new rates are established by the Commission.

The AGO disagrees with this Commission using a 1988 DEP case in its recent decision in Docket No. E-2 Sub 1142, regarding Duke's burden of proof of prudent and reasonable costs. The AGO states that under the Commission's "prudence framework" in the DEP Order recently issued, a utility's costs are presumed to be reasonable and prudent unless challenged, and the challenges presented must show three things: "(1) they must identify specific and discrete instances of imprudence; (2) demonstrate the existence of prudent alternatives; and (3) quantify the effects by calculating imprudently incurred costs." In re Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service In North Carolina, Docket No. E-2, Sub 1142, Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase, at 196 (Feb. 23, 2018)("2018 DEP Order")(citing the 1988 DEP Rate Order at 15) The AGO contends that this framework essentially puts the burden of proof on Intervenors. The AGO argues that it should be up to DEC to prove that some or all of the detailed costs are not attributable to its poor history of operations.

The AGO argues that evidence that the Company was noncompliant with regulatory requirements shows its imprudence, and cites Commissioner Brown-Bland's dissent to the 2018

DEP Order, indicating that violations of statutes that have the purpose of protecting the public from harm to life or safety constitute negligence per se. See Bell v. Page, 271 N.C. 396, 156 S.E.2d 711 (1967); Hampton v. Spindale, 210 N.C. 546, 187 S.E. 775 (1936). The AGO contends that DEC's five criminal convictions should be conclusive evidence of imprudence.

The AGO states that the Commission may consider an agency's standards or determinations when making its own determination about the prudence and reasonableness of coal ash activities, but cannot simply substitute another agency's determination or standards for its own. See State ex rel. Utils. Comm'n v. Carolina Water Service of North Carolina v. Public Staff, 335 N.C. 493, 503, 439 S.E.2d 127, 132 (1994).

The AGO states that coal has been utilized for many decades and beginning in approximately 1950, DEC, like many utilities, used unlined earthen impoundments to deposit its CCRs. The AGO states that in the 1970s, the United States Department of Energy directed that research be done on coal ash residuals and that the research revealed that there was a "growing awareness that the discarded wastes from coal combustion are a serious potential source of surface and ground water contamination" and that the wastes "have the potential for causing great environmental damage if not properly handled." 1979 Los Alamos Report, Tr. Ex. Vol. 12, pp. 189-204. In 1988, the EPA, in its Report to Congress on the topic of "Wastes from the Combustion of Coal by Electric Utility Power Plants," voiced concerns over the "substantial quantities of wastes" produced by electric utility power plants and concurred with the Los Alamos Report that "[t]he primary concern regarding the disposal of wastes from coal-fired power plants is the potential for waste leachate to cause ground-water contamination" from the potentially toxic metals in the ash due to the fact that "[m]ost utility waste management facilities were not designed to provide a high level of protection against leaching." 1988 EPA Report to Congress, Tr. Ex. Vol. 12, p. 228.

The AGO contends that before the North Carolina General Assembly passed CAMA, DEC's coal ash activities were governed by three important laws: North Carolina's Dam Safety Act, the federal Clean Water Act, and North Carolina's 2L Groundwater rules and that DEC violated all of these laws and standards.

First, the AGO alleges that DEC violated dam safety standards. The AGO states that during the five-year dam safety inspections between 1996 and 2009, all seven of the facilities were cited for issues regarding seeps. Tr. Vol. 11, p. 259. Between 1996 and 2009, the five-year dam safety inspectors also expressed concerns regarding stability issues at the Allen, Dan River, Marshall, Cliffside, and Riverbend Steam Stations. Tr. Vol. 11, pp. 261-262. After the TVA incident, the dams at these facilities were all rated by the EPA in 2009 as having either high hazard potential or significant hazard potential.

Second, the AGO alleges that DEC violated the Clean Water Act citing, among others, that in 2015, Duke pled guilty to five counts of criminally negligent violations of the Clean Water Act. In addition to the four charges involving Dan River, one charge stemmed from the unauthorized discharge of pollutants from an unpermitted channel that allowed contaminated water from its coal ash basin at its Riverbend Steam Station to be discharged into the Catawba River from at least November 8, 2012 through December 30, 2014. Ex. Vol. 12 pp. 355-356, 400-01; Ex. Vol. 12, pp. 302, 346-347. The AGO also cites that after the Southern Environmental Law Center threatened to filed civil lawsuits, DEQ initiated lawsuits against all of the Company's facilities which was resolved by the parties. The AGO also cites that on March 4, 2016, the DEQ issued Notices of Violation to Duke Energy Carolinas related to seeps. Tr. Vol. 11, p. 267. On January 8, 2018, the Company announced its entry into a proposed Special Order by Consent with DEQ to settle alleged water quality violations at the Allen, Marshall, and Cliffside Steam Stations. Id. Each of the seeps identified and addressed in the Special Order exhibited some indication of the presence of coal ash wastewater. Id. The Company paid $84,000 ($4,000 each for 21 seeps identified at these facilities prior to January 1, 2015) and committed to dewatering six coal ash ponds at these three facilities. Id. The resolution of these seeps is independent of the requirements of the CCR Rule and CAMA, and therefore any activities employed to resolve these seeps should be disallowed. Id.

Third, the AGO claims that DEC violated the 2L groundwater standards citing that in 2012 and 2013, when all of Duke's sites were monitored and the groundwater data gathered, the Company found and the EPA noted that there were exceedances of the groundwater 2L standards at all eight sites. 40 CFR Parts 257 and 261, 80 Fed. Reg. 74 (Apr. 17, 2015), p. 21455; AGO Late-Filed Exhibit 1-K-Nov. 4, 2013 Ash Basin Groundwater Summaries. The AGO provides that the Company gave notice of potential legal claims arising from groundwater contamination to its insurers in 1996 and 1997. In that correspondence, Duke advised its insurance carriers, AEGIS and Lloyd's of London, that it may have legal exposure for pollutant discharges from coal combustion residuals ponds at its coal-fired power stations. Ex. Vol. 10, p. 528; Ex. Vol. 10, p. 538. The AGO further states that on November 3, 2013, Duke Energy Corporation prepared a breakdown of data regarding exceedances of the 2L water quality standards for all of its facilities and found exceedances at all eight of the Company's plants. AGO Late-Filed Exhibit 1-K-"Nov. 4, 2013 Ash Basin Groundwater Summaries" Duke_USAO_01448182. Significantly, Allen Steam Station, Buck Steam Station, Dan River Steam Station, and W.S. Lee Steam Station had exceedances of both the primary and the secondary standards. Lastly, in its settlement of the 2013 court case, DEC agreed to perform groundwater remediation per CAMA and 2L. The AGO argues that CAMA only applies to surface impoundments, not inactive ash areas, N.C.G.S. 130A-309-200 et seq. (2017); therefore, any costs associated with the excavation and removal of inactive ash areas are patently related only to the Company's violation of groundwater regulations and should be disallowed.

The AGO further argues that DEC disregarded the law citing that Mr. Wells testified that "there was no obligation in the 2L rules to monitor groundwater quality" after the corrective action requirements were added, and in fact, the Company considered itself "under no universal obligation to monitor for groundwater impacts" until required to do so via a NPDES permit or other regulatory requirement mandated by the regulatory agency. Tr. Vol. 24, pp. 229-230. The AGO argues that the 2L Rules, since their promulgation in 1979, are and have always been founded on strict liability and self-enforcement principles. 15A N.C.A.C. 02L .0101 et seq. As stated in its Policy provisions, "[n]o person shall conduct or cause to be conducted, any activity which causes the concentration of any substance to exceed" the water quality standards specified in these Rules. 15A N.C.A.C. 02L .0103(d) (2017). As these Rules "are applicable to all activities or actions, intentional or accidental, which contribute to the degradation of groundwater quality," DEC had a duty to comply with these Rules. Id.

Next, the AGO argues that DEC understood the changing regulatory landscape for years and did not change its practices. The AGO cites many documents that prove this point. The AGO contends that as early as 2003, more than ten years prior to the enactment of CAMA and the Federal CCR Rule, DEC knew that at some point in the future, it would no longer be able to store wet ash in unlined surface impoundments but did nothing about it. Ex. Vol. 16, Pt. 2, p. 123. In January 2007, DEC noted that it would "be required to construct landfills for disposal of its non-saleable CCP . . . in the years to come ..." Ex. Vol. 16, Pt. 3, p. 50. In a document called "Duke Energy Environmental Management Program for Coal Combustion Products" dated May 29, 2007, Duke called "disposal in surface impoundments" the highest risk method of disposition of coal ash, and stated that this risk assessment should be used to support planning and management decisions. Ex. Vol. 16, Pt. 3, p. 60. In its 2010 Securities and Exchange 10-K filing, Duke Energy Corporation advised that it currently estimated that it would spend $131 million "over the period 2011-2015 to install synthetic caps and liners at existing and new CCP landfills and to convert some of its CCP handling systems from wet to dry systems to comply with current regulations." Ex. Vol. 16, Pt. 3, p. 238. Other documents include a 2013 Ash Basin Closure Strategy (AGO Late-Filed Exhibit 1-E-"Ash Basin Closure Strategy" p. Duke_USAO_01448357), review notes of an Environmental Review given to the Board of Directors of Duke Energy Corporation on August 27, 2013, (AGO Late-filed Exhibit 1-I.), and a presentation made to the Senior Management Committee on the "Ash Basin Closure Strategy on November 25, 2013. AGO Late-Filed Ex. 1-L p. Duke_USAO_1329810. The AGO states that in January 2014, less than a month before the Dan River spill, Duke Energy Corporation's Senior Vice President of Environmental Health and Safety acknowledged in a presentation to the Senior Management Committee that the Company's "coal ash is impacting the groundwater at all locations [and that] [t]his is not an overnight event, ash has been managed in this fashion for decades and it will take decades to close the ponds." Ex. Vol. 10, p. 611. Two of the recommendations given to the Senior Management Committee were to 1) "aggressively pursue closure of ash ponds at all decommissioned sites" and 2) "close all active ash ponds." Id. at 659. The AGO argues that despite the need to pursue the closure of its ash ponds and to convert to dry ash handling, DEC never implemented its own internal recommendations prior to the Dan River spill and the enactment of CAMA and the Final CCR Rule.

Next, the AGO argues that DEC failed to meet industry standards as it failed its duty to be a reasonable and prudent operator. The AGO further argues that under any standard, the Intervenors have shown the costs are not reasonable for cost recovery. The AGO states that it has shown discrete instances of imprudence, that prudent alternatives existed, and that imprudently incurred costs are enormous and certain disallowances should be made by the Commission. The AGO further argues that the Commission may "not allow an electric public utility to recover from the retail electric customers of the State costs resulting from an unlawful discharge to the surface waters of the State from a coal combustion residuals surface impoundment." N.C. Gen. Stat. § 62-133.13 (2014). This section of CAMA applies to discharges occurring on or after January 1, 2014. N.C.G.S. Session Law 2014-122, Sen. Bill 729, Part I, § (1)(b). The AGO states that it is not possible to determine exact disallowances, but the AGO contends that there are costs that would have resulted from the unlawful discharges to the surface waters of the State from at least the Riverbend plant cited in the Federal criminal case from January 1, 2014 to December 30, 2014. Ex. Vol. 12, pp. 400-401.

Next, the AGO submits that DEC should not receive "carrying costs" during amortization of the deferred CCR costs by placing the unamortized balance in rate base because the deferred CCR costs are not used and useful but rather are special operating expenses. According to the AGO, operating expenses are recoverable without return pursuant to N.C. Gen. Stat. § 62-133(b)(3) and State ex rel. Utils. Comm'n v. Thornburg (Thornburg I), 325 N.C. 463, 475, 385 S.E.2d 451, 458 (1989). Further, the AGO submits that the unamortized balance of the CCR deferred costs are similar to those considered in State ex rel. Utils. Comm'n. v. Carolina Water, 335 N.C. 493, 507, 439 S.E.2d 127, 135 (1994) (Carolina Water), where the Supreme Court considered whether the Commission erred when it treated utility plant that was not in service at the end of the test year – and would not be returned to service – as "an extraordinary property retirement," allowed amortization of the unrecoverable costs over ten years, and included the unamortized portion in rate base. The Court concluded that the costs were for plant that was not used or useful and, thus, the unamortized costs should not have been included in rate base. As the Supreme Court explained: "Including [these] costs in rate base allows the company to earn a return on its investment at the expense of the ratepayers." Id. at 508, 439 S.E.2d at 135.

Further, the AGO contends that the coal ash activities and expenditures are no longer related to ongoing or active property used or useful for providing utility service. The AGO states as support for this position that the costs in the asset retirement obligation are for the closure of basins and disposal of coal ash that Duke has identified with retired coal-fired steam stations (Ex. Vol. 16, Pt. 1, p. 24); the AGO argues that these coal ash closure and disposal costs are typically recovered in depreciation expense for long-term assets, as is recognized in the Commission's 2003 Order on Asset Retirement Obligations, DEC's internal evaluation of coal ash in 2014 contemplated the use of depreciation reserve funds, and Duke response to questions about whether such costs are included in depreciation expense in which DEC stated that the costs were not thought to result in a net negative salvage value, not that depreciation is inapplicable to such costs (Ex. Vol. 10, p. 691); depreciation costs are recovered over the 'useful life' of the asset. The AGO argues that no attempt has been made to define a useful life for the "property" that has generated coal ash expenditures and the retired plants where most of the costs were incurred do not have a remaining 'useful life' and no attempt has been made to identify the cost components, or consider the distinction between expenditures at operating versus retired plants or between expenditures such as those for construction of a landfill versus transportation costs.

The AGO posits that the fact that Duke has created an Asset Retirement Obligation for the coal ash expenditures does not dictate how the Commission must treat the costs for regulatory purposes. Deferral accounting is used to keep the regulatory accounting the same until a change in regulatory accounting is authorized. The AGO argues that imposing these coal ash costs on current ratepayers raises intergenerational fairness given DEC's failure to take action earlier. The AGO highlights that the Commission has previously dealt with the intergenerational issue when it considered whether to allow the recovery of manufactured gas plant clean-up costs based upon new environmental requirements. The AGO states that the Commission allowed recovery of the clean-up costs, however the amount was amortized over a period of years and no carrying costs were allowed on the unamortized balance.

The AGO contends that DEC's request to recover the deferred costs involves single-issue ratemaking, i.e., Duke seeks to recover coal ash costs going back to the beginning of 2015 – plus carrying costs – without review of the other rate elements that were in effect in 2015 that might offset the need for the cost recovery. With respect to the ARO, the AGO contends that DEC failed to request authorization to defer the coal ash costs before they were incurred and that the deferral in this case relates to Duke's establishment of an Asset Retirement Obligation for costs that are already accounted for in rates through amortization and depreciation. Lastly, the AGO argues that Duke's proposal to recover $201 million per year for ongoing coal ash costs as regular operating expenses is unreasonable and should be denied. Instead, Duke should be authorized to defer future costs for recovery in a future general rate case.

In its post-hearing Brief, CUCA contends that DEC's request for 100% CAMA compliance cost recovery is not appropriate. CUCA submits that DEC's costs are overstated and that many are the result of DEC's negligence, which is most clearly highlighted in DEC's guilty plea in the federal criminal environmental proceeding. CUCA supports an equitable sharing of the CCR cleanup costs due to the fact that CAMA costs are much higher than the CCR Rule compliance costs and that DEC's mismanagement directly led to the passage of CAMA. CUCA states that a 25% recovery is equitable. Further, CUCA contends that the CCR Rule is a self-implementing rule which has not been triggered by any citizen suits, and that in the absence of a regulatory directive to do so, DEC should not have pursued regulatory closure of operating sites. CUCA asks the Commission to revisit its analysis of management penalty in the DEP rate case order stating that the $30 million penalty amounts to a 1%[1] penalty which is too low based upon the evidence of DEC's negligence and criminal acts to come to a more fair result in this case. CUCA contends this division of costs sends the message that DEC is not being held responsible for its actions. Lastly, if the Commission does allow a similar 1% penalty in this case, it should also decrease the return on equity as DEC becomes a less risky company.

In its post-hearing Brief, CIGFUR III argues that DEC should not be allowed an equity component in the calculation of its deferred coal ash remediation carrying costs and that the appropriate amortization period is ten to fifteen years as opposed to five. CIGFUR III states that the total cost to defer is $497 million and that the carrying charges associated with the incurred coal ash costs since 2015 are $27 million, $6 million is associated with the cost of debt and $21 million is associated with the cost of equity. CIGFUR III further states that amortizing over 5 years results in annual amortization expense of $104.8 million, plus a $29.9 million net tax return, for a total requested revenue requirement of $135 million for deferred coal ash pond closure costs. CIGFUR III argues that the carrying costs should not include the equity component and that the deferral should be financed at the lowest option, which is the cost of debt. Allowing the equity component increases the amount charged to DEC's ratepayers and is inappropriate for such a significant expense that fails to enhance reliable service. CIGFUR III submits that the CCR costs were incurred over many decades and the stored coal ash is no longer used and useful in the provision of electric service. With respect to the run rate, CIGFUR III argues that DEC should not recover the run rate of $201 million and that DEC should defer ongoing costs for future recovery in its next rate case.

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[1] One percent relates to the penalty amount in relation to the Company's total CCR expenditures to comply with CAMA and the CCR rule, including future expenditures. Further, in relation to the DEP case, the 1% does not include the approximately $10 million discrete disallowance for transportation costs.

Sierra Club, in its post-hearing Brief, first discusses the legal standard for setting just and reasonable rates. Sierra Club argues that the closure of DEC's CCR basins is not in direct response to the CCR Rule or CAMA, but was made necessary because of DEC's unlawful discharges of CCR constituents to surface waters, and, therefore, DEC's closure costs are not recoverable under N.C. Gen. Stat. § 62-133.13. Further, Sierra Club contends that all of DEC's CCR basins are unlawfully discharging pollutants into surface waters and/or groundwaters, and that the only way to stop these unlawful discharges is to close the ponds and eliminate the source, the coal ash. Therefore, Sierra Club concludes that the cost of pond closures results from the unlawful discharges and are not recoverable.

Sierra Club submits that DEC failed to meet its burden to prove that storage of CCRs in unlined, leaking basins for decades was a reasonable and prudent way for DEC to manage its CCRs. According to Sierra Club, the DEC evidence provided by witnesses Kerin, Wells and Wright about the historical handling of CCRs being reasonable, prudent and consistent with industry standards over time is not credible. Rather, Sierra Club contends that: (1) DEC's groundwater monitoring did not comply with the EPRI standards set forth in EPRI's CCR manuals; (2) that DEC's continued use of unlined basins was contrary to the national trend toward lined basins or dry fly ash handling systems; and (3) that DEC's response to the surface water and groundwater pollution shown by its monitoring reports, once it finally began monitoring, was not reasonable or adequate. Sierra Club states that DEC's first facility to be converted to dry fly ash handling was the Belews Creek plant in 1983, after DEC became aware that selenium from sluiced coal ash was killing the fish in Belews Lake. The result, according to Sierra Club, was a 75% decrease in selenium concentrations.[1] Yet DEC did not use this information and experience to perform investigations at other plants, or to convert to dry fly ash handling at other plants.

Sierra Club also cites DEC's criminal pleas as evidence that DEC allowed unauthorized discharges of pollutants into surface waters. Sierra Club states that the environmental audits conducted as a part of DEC's plea arrangement identified unauthorized seeps containing pollutants above background levels at all DEC plants. Sierra Club contends that the evidence these unauthorized discharges of pollutants have been occurring for an undisclosed amount of time, and, pursuant to N.C. Gen. Stat. § 62-133.13, provide the basis for the Commission to deny all costs of dewatering the CCR basins, at a minimum.

With regard to groundwater pollution, Sierra Club states that DEC failed to follow the industry standard for monitoring compliance with the 2L requirements and, instead, conducted initial sampling at the Allen plant, then extrapolated that data to conclude that there was no violation of the 2L standards at DEC's other seven plants. Sierra Club contends that DEC did not conduct consistent groundwater monitoring at all of its plants until the 2000s, and that similar to the surface water audits the court ordered ground water audits found that CCR constituents are in the groundwater beneath all of DEC's CCR basins. In addition, Sierra Club points to DEC's 1996 insurance letter as proof that DEC knew about contamination above the 2L standards at Allen, Belews Creek, Dan River, Marshall and W.S. Lee as early as 1996.

[1] The selenium levels of concern at this site were from water discharges allowed from the NPDES permit rather than from groundwater leachate.

Sierra Club submits that the manner in which DEC failed to inspect and maintain the Dan River basin is indicative of its history of mismanagement and inaction with respect to CCR, and that this is conclusive evidence of imprudence, along with the following decisions made by DEC during the last 30 years:

(1) Failing to follow industry standards to stop using unlined basins.
(2) Waiting 20 years after the fish kill at Belews Creek to convert other plants to dry fly ash handling.
(3) Not conducting preliminary site investigations at all plants after the fish kill at Belews Creek.
(4) Waiting 30 years to regularly monitor ground water, contrary to the industry standard as of 1981.
(5) Not taking any action in response to the 1981 or 1982 EPRI manuals or the 1988 EPA Report, such as switching to lined basins, monitoring groundwater and dewatering basins.
(6) Spending millions of dollars on a leachate collection system at Allen and Marshall, then dumping the leachate into unlined basins at Allen and Marshall.

Moreover, Sierra Club argues that DEP's closure plans for its Allen and Marshall CCR basins do not comply with the CCR Rule or protect against continued discharges, and, therefore, DEC's proposed run rate should be rejected. Sierra Club contends that capping in place the Allen and Marshall CCR basins will not protect against continued contamination of ground water due to leaching of coal ash constituents into groundwater or into surface waters through migration.

NC WARN contends that DEC should not be allowed to recover any costs for the mitigation and cleanup of its CCR basins based on its extensive managerial mistakes and failures to take prompt action to correct known liabilities, and that no CCR costs should be borne by ratepayers. According to NC WARN, DEC has not met its burden of showing which of its CCR costs are capital expenses and which are operating expenses, N.C. Gen. Stat. § 62-133(b)(1) limits rate base recovery in rates to "property used and useful," and the statute does not include operating costs. As such, DEC's costs of compliance with federal and state directives stemming from CCR violations, and court orders mandating cleanup cannot be placed in rate base or otherwise recovered.

NC WARN also states that a review of the NC Clean Smokestacks Act is helpful because it provides guidance on what costs should not be allowed, such as costs incurred by the utility for failure to comply with any federal or state law, rule, or regulation for the protection of the environment or public health, and criminal or civil fines and penalties. N.C. Gen. Stat. § 62-133.6(a)(2). NC WARN asserts that the evidence shows that all of the costs incurred by DEC relating to CCR came from court orders and criminal plea agreements, and that DEC took no actions voluntarily, even actions that could have minimized subsequent costs and mitigated environmental damage. Further, NC WARN states that the evidence shows that DEC "knew or should have known" about the significant problem of leaking CCR basins in the early to mid-1980s, if not before, and that the industry standard increasingly became lining CCR basins to prevent water contamination. NC WARN points to DEC's insurance letters in 1996, 2011, and 2016 regarding potential damages and future compensation for mitigation and cleanup costs as significant evidence of what DEC knew or should have known, and contends that the refusal by the insurance companies to cover these multi-million dollar claims demonstrates DEC's culpability for at least the last 20 years. In conclusion, NC WARN submits that DEC mishandled its coal ash for decades, taking the least expensive options, and disregarding the substantial negative impacts of coal ash on families, property, and water supplies adjacent to the coal ash basins, and that the evidence demonstrates criminal negligence, millions in fines and penalties, and a number of judicial decisions and regulatory actions requiring DEC to do what it should have done all along.

E. The Position of Public Staff Witnesses Garrett and Moore

Public Staff witnesses Garrett and Moore testified that they investigated the prudence and reasonableness of costs incurred by DEC with respect to its coal ash management. In addition, they reviewed the approach taken by DEC to determine the least cost method of achieving compliance with the laws and regulations governing coal ash management. Witnesses Garrett and Moore testified that in some circumstances, DEC incurred costs associated with management of coal ash from CCR units that were not required under State or federal law. In those circumstances, witnesses Garrett and Moore evaluated the specific facts and details surrounding those CCR units to determine whether they agreed that DEC's management of those CCR units was reasonable and prudent. To the extent they believed that DEC's actions and costs incurred were not reasonable nor prudent, they recommended that the Commission disallow these costs. In conducting their investigation, witnesses Garrett and Moore reviewed the closure plans and coal ash-related costs incurred for all of DEC's coal-fired facilities, conducted extensive discovery, participated in numerous meetings, and visited several of the DEC facilities in question. Tr. Vol. 21, pp. 19-20.

Witnesses Garrett and Moore did not take exception with DEC witness Kerin's general characterization of the applicable federal and State regulations addressing the management and closure of coal ash basins in North Carolina and South Carolina. They did, however, identify several decisions made by DEC they maintained that were not required by law or where lower-cost compliance options were available, which they described in further detail in their testimony. Tr. Vol. 21, pp. 20; 50.

With regard to DEC's Allen, Belews Creek, Buck, Cliffside, and Marshall plants, witness Moore noted that DEQ issued final classifications for these facilities as "Low to Intermediate Risk" in May 2016, and that DEP is in the process of establishing the permanent replacement water supplies required under N.C. Gen. Stat. § 130A-309.211(c)(1) and performing the applicable dam safety repair work at these sites. Tr. Vol. 21, p. 54. Upon completion of these tasks within the timeframe provided, the impoundments at these facilities will be reclassified as low-risk pursuant to N.C. Gen. Stat. § 130A-309.213(d)(1). He explained that CAMA requires, at a minimum, that the impoundment be dewatered and closed either by excavation or by placement of a cap system that is designed to minimize infiltration and erosion. Witness Moore noted that this approach is generally the most cost-effective means for closure of a CCR unit. He also testified that CAMA (S.L. 2016-95) does not require the submission of proposed closure plans for low- and intermediate risk impoundments until December 31, 2019, so DEC has not submitted a Site Analysis and Removal Plan (SARP) to DEQ for any of the Low to Intermediate risk facilities at this time. He maintained, therefore, that a prudence review of the closure plans would be premature, so witness Moore took no exception in the present case to DEC's current proposed closure method for the coal ash basins located at Allen, Belews Creek, Buck, Cliffside, and Marshall. Tr. Vol. 21, pp. 55-57.

Public Staff witness Moore took exception to DEC's closure method for the CCR units located at Buck Steam Station. Duke selected Buck, along with DEP's Cape Fear and H. F. Lee Stations, as the three beneficiation sites pursuant to N.C. Gen. Stat. § 130A-309.216, which required Duke to identify three sites located within the state with ash stored in the impoundments suitable for processing for cementitious purposes. Upon selection of the sites, Duke was required to enter into a binding agreement for the installation and operation of ash beneficiation projects at each site capable of annually processing 300,000 tons of ash to specifications appropriate for cementitious products, with all processed ash to be removed from the impoundments located at the sites. Tr. Vol. 21, pp. 58-61. Witness Moore also noted that the timeframe proposed by DEC for beneficiation of the Intermediate Risk sites extends beyond the closure timeframe called for in Section 3.(a) of S.L. 2016-95 for sites deemed Intermediate Risk, and that N.C. Gen. Stat. § 130A-309.215 provides a variance option for closure deadlines that are found to be in the public interest. Id.

Public Staff witness Moore testified that instead of selecting Buck, Duke should have selected the CCR units located at Weatherspoon as one of the three beneficiation sites as required by N.C. Gen. Stat. § 130A-309.216, where Duke has selected the excavation of CCR and beneficial use option, with contracts in place for the delivery of the coal ash material to facilities in South Carolina for use in the concrete industry. This would have allowed the Buck Station to instead utilize significantly lower cost closure options instead of cementitious beneficiation. CCR units at Buck could have been classified as low risk upon completion of the establishment of permanence replacement water supplies and completion of applicable dam safety repair work, and instead may have been eligible for closure under the "cap-in-place" closure method under CAMA, which would have significantly lowered closure costs for Buck. Tr. Vol. 21, pp. 59-61. Witness Moore therefore recommended that the Commission disallow the $10 million already incurred by DEC for the cementitious beneficiation project at Buck. Tr. Vol. 24, p. 108.

With regard to DEC's selected closure actions at the Dan River Plant, witness Moore took exception with DEC's decision to excavate and transport coal ash from Ash Stack 1 at Dan River off-site to the Maplewood Landfill in Amelia, Virginia. He contended that had DEC conducted an adequate assessment of on-site greenfield landfill options at the time it began evaluating off-site disposal options, it would have identified viable on-site disposal options that would have allowed DEC to dispose of all of the ash on-site without having incurred the added expenses associated with the off-site transfer and disposal. Tr. Vol. 21, pp. 62-70.

Witness Moore disputed DEC's position that the moratorium on CCR landfills, which was enacted on September 20, 2014, in Section 5.(a) of S.L. 2014-122, and expired on August 1, 2015, had any impact on DEC's ability to construct an on-site greenfield landfill at Dan River in a timely fashion. He also noted that there were no regulatory obligations related to coal ash management that required removal of CCR materials from Ash Stack 1 as stated by DEC, particularly under the aggressive timeframes required for high-priority sites under CAMA. He evaluated DEC's investigation of on-site landfill options, particularly along the western boundary of the property, and found that DEC had no records documenting any evaluation of the area. With regard to the reasons provided by DEC as to why it did not utilize the area between the combined cycle plant and the western property boundary, Public Staff witness Moore found no valid technical reasons why an adequately sized on-site landfill could not have been located along the western boundary to have handled all of the ash on-site without having to incur the significant costs associated with off-site transportation costs and construction of rail handling equipment. Tr. Vol. 21, pp. 64-66.

As a result of DEC's unnecessary actions to transport ash off-site from the Dan River facility, witness Moore recommended a total disallowance at the Dan River facility of $59.3 million from DEC's coal ash expenditures during this recovery period. Public Staff Moore Exhibit 4.

Witness Moore summarized the coal ash closure approach taken by DEC at its Riverbend facility. Witness Moore testified that CAMA required the excavation of CCR materials from the Primary Ash Basin and the Secondary Ash Basin, but there were no regulatory obligations that required removal of CCR materials from the Ash Stack Area or the Cinder Pit. Witness Moore did not take exception with DEC's plan to remove this additional material, but he did take exception with DEC's decision to utilize the Brickhaven structural fill facility for off-site disposal. Tr. Vol. 21, p. 70, 72. Witness Moore testified that the Brickhaven facility did not present any scheduling advantages or reduce costs, and instead resulted in increased delays and litigation resulting from community opposition to the proposed project. Witness Moore testified that the DEC-owned on-site landfill at the Marshall Facility should have been utilized for the disposal of all ash from Riverbend. Tr. Vol. 21, p. 86.

Witness Moore did, however, take exception to DEC's decision to haul approximately 17,000 tons of CCR material from the Ash Stack Area by truck to the R&B Landfill in Homer, Georgia. Instead, Witness Moore stated that DEC could have utilized the landfill at the Marshall Facility for the CCR material, resulting in shorter hauling distances and lower disposal costs. Witness Moore recommended that the Commission disallow the $489,600 premium paid to transport and dispose of the 17,000 tons of CCR material to the R&B Landfill, as opposed to the Marshall Station. Tr. Vol. 21, pp. 72-74.

Public Staff witness Garrett focused his testimony on the activities undertaken by DEC at its W.S. Lee site in South Carolina. Witness Garrett agreed with DEC's decision to utilize an on-site landfill to dispose of the ash material in the Primary Ash Basin and Secondary Ash Basin at W.S. Lee, noting that this approach was consistent with Duke Energy's stated guiding principles and provided a lower cost closure solution compared to an off-site landfill. Tr. Vol. 21, pp. 39-40. Witness Garrett also concurred with DEC's decision to take some actions at the Inactive Ash Basin (IAB) and the Old Ash Fill to mitigate risk associated with long-term environmental issues at the site, but he did not agree with DEC's decision to immediately begin excavation and transportation of ash to the R&B landfill in Homer, Georgia. Witness Garrett instead testified that DEC should have followed the recommendations of its consulting engineers, which recommended repair and maintenance on the IAB berm in 2014, rather than immediate excavation. Witness Garrett further stated that DEC failed to provide a regulatory or technical reason to substantiate immediate removal of the ash from the IAB. Witness Garrett therefore recommended that the Commission disallow approximately $27 million from DEC's request, which is the premium associated with the costs incurred by DEC to transport ash to Homer, Georgia, as opposed to excavating and landfilling on-site. Tr. Vol. 21, pp. 40-41.

Witness Garrett also took exception with DEC's plan to excavate and dispose of the coal ash material contained in the Structural Fill area at W.S. Lee, because the area was developed in accordance with all applicable environmental regulations, is not in close proximity to the Saluda River, has been effectively capped in place, and does not pose any environmental concerns in its present state. Id.

F. Public Staff Witness Junis' Equitable Sharing And Coal Ash Adjustment Testimony

Public Staff witness Junis listed three conceptual options for regulatory treatment of coal ash costs. The first option is to allow full recovery of coal-ash related costs on the grounds that the costs have been reasonably incurred to comply with CAMA and the CCR Rule. Tr. Vol. 26, p. 721. This is essentially the approach recommended by DEC, minus fines, penalties, and other specific costs listed in their federal criminal plea agreement as non-recoverable in rate proceedings. Id. The second option is to disallow recovery of costs to comply with CAMA on the grounds that CAMA is the direct consequence of imprudent DEC environmental violations. Tr. Vol. 26, pp. 721-22. The third option is to disallow the costs incurred to defend and remedy environmental violations, except to the extent that CAMA requirements increased the cost of remediation. Tr. Vol. 26, p. 722. Under this approach, which the Public Staff advocates in theory, disallowances would be based on the costs to remediate environmental violations rather than the costs flowing from CAMA compliance. Id.

While the Public Staff supports the third option in theory, witness Junis encountered "complicating factors" that led him to modify this preferred regulatory treatment for practical reasons. Id. He observed that, while some environmental violations are clearly due to Company negligence, others fall into a gray zone where they are neither clearly imprudent nor clearly reasonable. Tr. Vol. 26, p. 723. For instance, decisions to place coal ash in unlined impoundments could have been reasonable based on what DEC knew or should have known at the time the basins were constructed some decades in the past. Tr. Vol. 26, pp. 723-24. At the same time, Public Staff witness Junis explained that it can be unreasonable to impose on ratepayers the costs incurred because those impoundments leaked coal ash constituents and contaminated groundwater outside the compliance boundaries, in violation of state environmental laws and regulations. Tr. Vol. 26, p. 724. Witness Junis also noted that calculating the costs of many environmental violations would be too speculative as such calculations would involve estimations based on scenarios that did not occur (e.g., preventing violations through basin construction or modification some decades earlier, or remedying violations if CAMA had not been enacted). Tr. Vol. 26, p. 725.

Due to the complicating factors, witness Junis offered a more practical approach that would exclude certain coal ash costs from recovery in rates as follows:

(1) DEC litigation costs incurred during the test year in cases where there are environmental violations;
(2) costs to remedy environmental violations where the costs exceed what CAMA would have required in the absence of environmental violations;

(3) fines, penalties, and other costs associated with the federal criminal plea agreement involving the Dan River and Riverbend plants, payments to DEQ to settle the assessment of penalties involving the Dan River plant, and the penalty for groundwater violations at DEC and DEP plants including Belews Creek and Sutton;
(4) the adjustments and disallowances recommended by Garrett and Moore to the extent there is no double disallowance for the same item; and
(5) an equitable sharing of the remaining allowed costs of coal ash management through the deferral and amortization approach recommended by Public Staff witness Maness.

Tr. Vol. 26, pp. 727-28.

Witness Junis noted that DEC has removed the costs listed in item (3) above from its rate request. Tr. Vol. 26, p. 728. Thus, the regulatory treatment of those costs is not in dispute. The disallowances recommended by witnesses Garrett and Moore are discussed elsewhere in this order. The remaining cost exclusions listed by witness Junis include litigation-related expenses in cases of environmental violations. In this category, he recommended exclusion of $2,109,406 (total system, not just NC retail, as shown in Boswell Exhibit 1, Schedule 3-1(n), line 1) of test year outside legal fees for litigation of the state enforcement actions filed by DEQ alleging violations at all of DEC's North Carolina plants and, to any extent they have not already been excluded by DEC, for litigation of the penalties assessed by DEQ for violations at the Dan River plant. Tr. Vol. 26, pp. 730-31. Witness Junis asserted that there is compelling evidence of the environmental violations on which these legal actions were based. Tr. Vol. 26, p. 731. He referenced a number of the exhibits to his testimony detailing DEQ data in support of this assertion. Id.

For the category of costs to remedy environmental violations where the costs exceed what CAMA would have required in the absence of environmental violations, witness Junis identified, to date, $1,288,526 (total system) of expenditures incurred from January 1, 2016, through November 30, 2017, for extraction wells and treatment of groundwater at DEC's Belews Creek plant pursuant to the settlement agreement between DEQ and DEP in the Sutton penalty assessment case. Tr. Vol. 26, pp. 733-34. He took the position that these costs would not have been incurred but for unlawful contamination of groundwater by DEC's Belews Creek ash basins, and that these costs are over and above the lowest reasonable costs of CAMA compliance in the absence of violations. In addition to the costs associated with extraction wells and treatment of groundwater, witness Junis identified $857,350 of expenditures for selenium removal equipment at DEC's Riverbend plant on the grounds that this equipment had not been placed in operation at the time of his testimony. Tr. Vol. 26, p. 734. Witness Junis noted that there could be additional costs in this category in the future. Tr. Vol. 26, p. 732.

The final category for disallowance is based on an "equitable sharing" of all coal ash-related costs not otherwise disallowed. Tr. Vol. 26, p. 738. Witness Junis referred to witness Maness' testimony for description of how the equitable sharing should be implemented and the reasons for it. Id. Witness Junis further testified that "An equitable sharing is particularly appropriate in light of the extent of the Company's failure to prevent environmental contamination from its coal ash impoundments, in violation of state and federal laws." Tr. Vol. 26, p. 738. In support of his opinion, he noted the nature and extent of coal ash environmental problems addressed in the federal criminal plea agreement, unlawful discharges, dam safety deficiencies, and numerous groundwater violations. Tr. Vol. 26, p. 739. He added that the sheer number of legal actions against DEC for coal ash environmental violations, while not evidence of the Company's guilt, is suggestive of the extent of the problem. Tr. Vol. 26, pp. 739-40. Witness Junis asserted that the numerous lawsuits regarding DEC's non-compliance with N.C. Gen. Stat. § 143-215.1 and state groundwater rules would in all probability have led to environmental cleanup costs even if CAMA and the CCR Rule had not been adopted, and that the costs of impoundment closures under CAMA and the CCR Rule overlap what would otherwise have been coal ash cleanup costs under existing state and federal environmental laws and regulations. Tr. Vol. 26, p. 741. Based on DEC's culpability for environmental violations, witness Junis testified that an equitable sharing would be appropriate, whereas it would be unreasonable and unjust to burden ratepayers with all the coal ash-related costs when ratepayers were not culpable for the environmental violations. Tr. Vol. 26, pp. 741-42.

Witness Junis responded to DEC witness Kerin's assertion in his testimony that the EPA's 2015 Effluent Limitations Guidelines (ELG) Rule forced DEC to convert its coal-fired plants to dry ash handling. Tr. Vol. 26, p. 742. Witness Junis noted that conversion to dry ash handling or cessation of operations is a requirement of CAMA, which was enacted in 2014, and, thus, the ELG Rule, which was not promulgated until 2015, was not the driver of this outcome in North Carolina. Tr. Vol. 26, p. 743.

Witness Junis disagreed with Company witness Kerin's testimony that DEC had not done anything to cause it to incur any unjustified coal ash-related costs, and he disagreed with witness Wright's minimization in his testimony of the role of the Dan River spill on the enactment of CAMA. Tr. Vol. 26, pp. 743-44. He stated that Dan River spill "was a large contributing factor to the creation of CAMA, which forced the Company to take expensive corrective actions." Tr. Vol. 26, p. 744. He further noted that Senate President Pro Tem Phil Berger recommended that the spill be discussed in the General Assembly's next meeting in a press release issued four days after the spill, and that the first version of CAMA directly referenced the spill in its preamble. Tr. Vol. 26, p. 745.

Witness Junis also disagreed with Witness Wright's assertion that the Commission should treat DEC the same as it treated DNCP in its 2016 rate case, in which the Commission approved amortization with a return for DNCP's past deferred coal ash costs. Tr. Vol. 26, p. 747. Witness Junis stated that the volume of environmental regulatory action against Dominion was miniscule compared to that against DEC, and that this was borne out by the Company's own responses to Public Staff Data requests in which it failed to produce evidence of environmental violations by DNCP after 1993. Tr. Vol. 26, p. 748.

In supplemental testimony, witness Junis recommended disallowance of an additional $206,553 in expenditures for groundwater extraction and treatment at DEC's Belews Creek plant listed in DEC witness McManeus' second supplemental testimony, which updated coal ash costs through December 31, 2017. Tr. Vol. 26, pp. 752-53. This recommendation is based on the same grounds for the disallowance of groundwater extraction and treatment costs detailed in witness Junis' direct testimony.

In his initially filed and supplemental direct testimony, Public Staff witness Maness identified the following seven adjustments to the Company's proposed recovery of coal ash costs. Some of the adjustments incorporate recommendations from other Public Staff witnesses:

a. Witness Maness incorporated adjustments to reflect a prudent and reasonable level of coal ash expenditures as recommended by Public Staff witnesses Moore, Garrett, and Junis. Tr. Vol. 22, pp. 65-66, 147, 153-54.

b. Witness Maness recommended adjusting the N.C. retail jurisdictional allocation factors to (a) allocate the costs DEC has identified as "CAMA Only" costs by the comprehensive allocation factor, rather than a factor that does not allocate costs to South Carolina retail operations; and (b) allocate all coal ash expenditures by the energy allocation factor, rather than the demand-related production plant allocation factor.

c. Witness Maness recommended addition of a return on deferred coal ash expenditures from December 2017 through April 2018, to bring the total balance up to the expected effective date of the rates approved in this proceeding. Tr. Vol. 22, pp. 69-70. The Company accepted this approach in its Second Supplemental Filing, as noted above. However, the Company has calculated the 2018 net-of-tax debt carrying cost using a Federal income tax rate of 35%; witness Maness recommended using the updated 2018 rate of 21%. Tr. Vol. 22, pp. 149-50.

d. Witness Maness recommended calculation of the return on the deferred coal ash costs be made with a mid-month cash flow convention, rather than the beginning-of-month convention used by the Company. Tr. Vol. 22, p. 70. The Company accepted this approach in its Second Supplemental Filing, as noted above. However, the Company had continued to apply compounding at the end of January each year. Witness Maness continued to recommend compounding carrying costs at the beginning of January each year. Tr. Vol 22, p. 149.

e. In conjunction with the Public Staff's proposal for equitable sharing of coal ash costs between ratepayers and investors, witness Maness recommended amortization of the balance of deferred coal ash expenditures over a 25-year period, rather than the 5-year period proposed by the Company. Tr. Vol. 22, pp. 70-85, 153-54.

f. Also in conjunction with the Public Staff's proposal for equitable sharing of coal ash costs between ratepayers and investors, witness Maness recommended reversal of the Company's inclusion of the unamortized balance of coal ash expenditures in rate base; this reversal, in conjunction with the 25-year amortization period, would produce a 49% ratepayers / 51% investors sharing of the burden of deferred coal ash expenditures. Tr. Vol. 22, pp. 70-85, 153-54, 162.

g. Witness Maness recommended removal of the ongoing annual expense amount, or "run rate," proposed by DEC to recover additional coal ash management costs incurred from the date the rates approved in this proceeding become effective through the date rates become effective in DEC's next general rate case.

G. Company Witnesses – Rebuttal

Rebuttal testimony with respect to the reasonableness and prudence of the Company's coal ash basin closure costs was provided by Company witnesses Kerin, Wright, and Wells. Rebuttal testimony with respect to witness Maness' proposed adjustments was provided by witness McManeus. Rebuttal testimony with respect to the Company's entitlement to earn a return on the unamortized balance of coal ash costs, ARO accounting and the "used and useful" concept, was provided by witnesses Wright, McManeus, and Doss. Such testimony is summarized as follows.

1. Kerin

Company witness Kerin's rebuttal testimony responded to the direct testimony of Public Staff witnesses Garrett, Moore, and Junis, CUCA witness O'Donnell, AGO witness Wittliff, and Sierra Club witness Quarles. As in the DEP proceeding, witness Kerin testified that witnesses Garrett and Moore engaged in a robust analysis and investigation of the costs that DEC incurred to comply with the CCR Rule and CAMA, and he agreed with the majority of their conclusions. He also stated that based on a complete review of the applicable facts and real world conditions, he did not believe their suggested disallowances were warranted, and that they again missed or overlooked key facts in several of their recommendations. Tr. Vol. 24, pp. 90-92.

First, he disagreed with witness Moore's conclusion that it was imprudent and unreasonable for DEC to transport CCR material from Dan River to a landfill in Virginia until the on-site CCR landfill could be constructed, and with their recommended disallowance of $59,320,890, which represents the difference between the cost to transport the material off-site and the cost to dispose of it in what he classified as a hypothetical and impractical on-site landfill along the western property boundary. Witness Kerin stated that witness Moore conceded that the CAMA moratorium prohibited construction of new or expanded CCR landfills located wholly or partly on top of the Primary Ash Basin, Secondary Ash Basin, and the Ash Fill 1 and 2 areas. He also stated that, while witness Moore correctly asserted that the moratorium did not prohibit construction of landfills in other areas of the site, specifically near the western property boundary, based on the Company's exploration of off-site and on-site locations for a CCR landfill for the Dan River ash, locating the on-site landfill on the western property boundary was never a feasible option due to multiple factors that witness Moore did not consider. Tr. Vol. 24, pp. 92, 94-105, 131.

Witness Kerin explained that in June 2015, Duke Energy purchased two tracts of land near Dan River (the Hopkins Tracts), which together with the Dan River plant were subject to a City of Eden zoning ordinance that made landfill construction on those properties cost prohibitive. He explained further that, while DEC and the City of Eden entered into an agreement whereby the City amended its zoning ordinance to allow landfill construction on the Dan River property, several limitations were imposed on the location of an on-site landfill. The landfill could only be located on the Dan River Facility premises, not on the Hopkins Tracts. In addition, the on-site landfill needed to be located near the existing basins, and as remote from residential areas as feasible. Witness Kerin noted that the nearest location to the existing basins is within the footprint of the former ash stack, and that this is the location DEC chose for the landfill. This choice also minimized impacts to surrounding properties by ensuring that the landfill was located as far as feasibly possible from neighboring properties. He stated that, because witness Moore's proposed location, in contrast, was not closest to existing basins or as remote as feasible from residential areas, the City of Eden would not likely have approved the zoning required to construct the landfill in this location. Witness Kerin stated that, if witness Moore had considered the City of Eden agreement, he could not have concluded that his alternative landfill location was reasonable or prudent. Tr. Vol. 24, pp. 95-96.

Witness Kerin maintained further that construction of the landfill in witness Moore's proposed location would require complete excavation of a LCID Landfill on the site. He explained that DEQ had allowed Duke Energy to dispose of asbestos in the Dan River LCID Landfill, and stated his opinion that North Carolina regulators would not allow DEC to disturb a covered landfill containing asbestos. This is because, while asbestos that is covered and in a landfill poses little to no risk to environmental health or safety, when uncovered and disturbed through excavation, it becomes friable and will be released into the air, posing an unacceptable risk to workers and, potentially, neighbors. Witness Kerin also testified that, even if the Company were allowed to excavate the LCID Landfill, disposal of the fill material would have posed additional challenges. While witness Moore asserted that the Company could have disposed of the material at the Rockingham County Landfill, witness Kerin stated that it is not clear that that location would have accepted the volume of asbestos—at least 60,000 cubic yards—required to be excavated from the LCID Landfill. Even if Rockingham would accept the asbestos, because it imposes strict double-bagging requirements for asbestos waste, this requirement would prohibit pursuing this alternative from an operational and labor standpoint. Tr. Vol. 24, pp. 97-98.

Witness Kerin stated that DEC also located the on-site landfill so that it does not interfere with existing streams and wetlands on the Dan River Plant premises. He stated that witness Moore's alternative location would in contrast interfere with two streams and two wetlands and impact several others, which would have required the Company to apply for U.S. Army Corps of Engineers (USACE) and DEQ permits to address those impacts. He also stated that, in the Company's experience, it is not likely that USACE would have approved the requisite permits, or would not have done so in time for the Company to meet the closure deadline of August 2019, especially considering that another on-site location – the one chosen by DEC – would have no impacts to streams or wetlands. He contended that witness Moore's proposal neither avoids nor minimizes impacts to jurisdictional waters, and relies solely on cost as support for his location. He asserted that the location that DEC chose for the landfill allowed it to proceed without litigation or delay, and will allow it to meet its CAMA imposed excavation deadlines. Tr. Vol. 24, pp. 98-100.

Witness Kerin maintained in addition that witness Moore's alternative location did not consider elevation changes and other topographical features, such as the steep slopes on the alternative site that lead to and through streams and wetlands. He also asserted that the steep grading limits the airspace that can be realized for developing a lined landfill of the size needed, and the elevation of witness Moore's proposed location would result in the landfill being in neighbors' line of sight. Witness Kerin also asserted that the land along the western property boundary is not suitable for landfill construction, as the depth to bedrock is fairly shallow, leaving little room for excavation for fill volume, borrowing soil or buffering to groundwater. He asserted further that the slope to stream combination on the western and southern sides of witness Moore's proposed landfill location leaves no area for stormwater management on the low side of the landfill, and that significant borrow resources would be required to fill the toe of the slope to achieve enough buffer from the stream for landfill access and stormwater features, adding expense and time to the project. Further, he maintained that the Company would have needed to obtain a new construction permit and construct an industrial NPDES outfall through the service water pond in order to build witness Moore's proposed landfill, and that both the permit and the outfall would have required substantial time to obtain and construct and would have to be in place before construction on the landfill began. In addition, he maintained that the 100-year flood plain in this area intrudes into portions of witness Moore's proposed location, and would present additional permitting challenges and likely not leave sufficient space for required stormwater management features on the site. Tr. Vol. 24, pp. 100-02.

Finally, with regard to Dan River, witness Kerin maintained that, even if DEC could have overcome all of the obstacles to witness Moore's proposed site, the proposed disallowance was incorrectly calculated. He explained that witness Moore did not correctly calculate the Company's costs for excavating, transporting, and disposing of Ash Stack 1 off-site, and that his proposed $83,531,985 disallowed should be reduced by approximately $3.8 million that is actually attributable to excavation and transportation of ash from the Primary Ash Basin. Witness Kerin also asserted that witness Moore's cost estimates to construct his alternative landfill are too low. He explains that when the presence of asbestos and the need to relocate the warehouse building in the center of the alternative location are accounted for, the cost to build witness Moore's alternative location landfill jumps by $10,790,900 to $35,001,095, thereby reducing witness Moore's proposed disallowance further, to $44,742,265. Witness Kerin emphasized that, because witness Moore's proposed site was not a viable option and never considered by the Company for the myriad reasons he discussed, this recalculation is hypothetical, but that it shows that witness Moore's proposed disallowance is incorrect even if his suggested course of action were possible, which it was not. Tr. Vol. 24, pp. 103-05.

Witness Kerin also disagreed with witness Moore's contention that DEC should have chosen Weatherspoon over Buck as a beneficiation site, and with the recommendation that $10,612,592 associated with beneficiation costs at Buck be disallowed. N.C. Gen. Stat. § 130A-309-216 requires an impoundment owner to: (i) identify two sites by January 1, 2017 and an additional site by July 1, 2017; and (ii) enter into a binding agreement for the installation and operation of an ash beneficiation project at each site capable of annually processing 300,000 tons of ash to specifications appropriate for cementitious products, with all ash processed to be removed from the impoundments located at the sites. Witness Kerin maintained that in keeping with the timing requirements imposed by CAMA, Duke Energy identified Buck, H.F. Lee, and Cape Fear as the three beneficiation sites based on its conclusion that they offered the most feasible alternative and the best economic value to customers while complying with CAMA. While he agreed that reuse of ash at Weatherspoon is appropriate, and noted that the Company is selling Weatherspoon ash for reuse today, he disagreed that Weatherspoon was a possible choice for one of the three beneficiation sites required by CAMA. Tr. Vol. 24, pp. 93, 105-08, 131.

Witness Kerin explained that witness Moore mixes apples and oranges by contending that by selecting Buck as a beneficiation site and therefore supplying an additional 300,000 tons per year of CCR material to the concrete industry, the Company in turn reduced demand for the 70,000 tons per year of CCR material for the same purposes from Weatherspoon for which Duke Energy was unable to find a purchaser. He explained that Weatherspoon ash is sold under contract to cement manufacturers and is used as raw material or aggregate in the manufacture of cement, while beneficiated ash from Buck is used as a replacement for cement in concrete. Because these are separate products that are used for different purposes, the sale of beneficiated ash from Buck has no impact on the demand for ash from Weatherspoon. Tr. Vol. 24, pp. 105-06.

Witness Kerin maintained further that witness Moore's assertion that choosing Buck increased closure costs at that site compared to other closure options misses several key facts that support the decision to select Buck as the third beneficiation site. He noted that Weatherspoon contains only 2.4 million tons of ash, which is approximately one-third the 6.4 million tons at Buck, and that the Company reasonably considered the amount of ash available at the site, and the potential uses for the ash when making decision to invest in beneficiation at a particular location. Witness Kerin also maintained that Weatherspoon is in a poor geographic location in relation to the major markets for ash used in the cement industry. He explained that since trucking the ash is part of the cost of the sales, with its proximity to Charlotte and Greensboro, Buck is in a much better location for beneficiation, and has the highest revenue projection, followed by Cape Fear (Greensboro and Raleigh) and H.F. Lee (eastern North Carolina and Virginia). Witness Kerin noted further that, even after issuing an RFP, Duke Energy has only been able to secure a buyer willing to enter into a long-term contract for 230,000 tons of ash from Weatherspoon, but not the additional 70,000 tons to qualify the site for beneficiation. He also asserted that the statute's specific references to installation and operation of an ash beneficiation project and production indicates the General Assembly's intent that Duke Energy construct and operate technology such as carbon burn-out plants and STAR technology, rather than use the basic drying and screening operations occurring at Weatherspoon. Tr. Vol. 24, pp. 106-07.

Witness Kerin also disputed witness Moore's recommendation that the Commission disallow recovery of $2,000,100 related to DEC's purchase of nine adjacent parcels at Cliffside. He stated that witness Moore's conclusion ignores one of the Commission's and DEC's core policies, which is to encourage and promote harmony between public utilities, their users and the environment. He also noted that the cost of the Cliffside parcels was not included in the costs the Company is seeking to recover in this case, and has never been part of the Company's ARO and as such the recommended disallowance of these costs should not be granted. Tr. Vol. 24, pp. 93, 108.

Witness Kerin also objected to witness Moore's suggestion that the $489,000 in costs to ship ash from Riverbend to Homer, Georgia should be disallowed on the basis that the ash could have been shipped to DEC's Marshall Steam Station. Witness Kerin testified that shipping ash to Homer, Georgia was a reasonable, temporary solution that allowed DEC to begin required ash excavation within the mandatory time frame after Riverbend received its NPDES stormwater permit. He explained that the Company sent Riverbend ash to Marshall once that site became available, but that Marshall was not an available location in May 2015, when the Company began trucking ash from Riverbend pursuant to DEQ directives. Those directives, as contained in an August 13, 2014, letter from DEQ, requested that Duke Energy submit an excavation plan for Riverbend by November 15, 2014, and that it begin removing ash at Riverbend within 60 days of receiving DEQ approvals to do so, which included an NPDES Stormwater Permit. Since DEQ issued the permit on May 15, 2015, DEC had until July 15, 2015, to begin excavating Riverbend ash. He stated that while the Company was exploring long-term options to receive the Riverbend ash, it was still obligated to meet this deadline, and thus it was imperative that the Company find someone to haul and dispose of the Riverbend ash on a short turnaround. Waste Management National Services, Inc. (Waste Management) was able to meet that requirement, and began trucking ash from Riverbend on May 21, 2015, and transported the final load on September 18, 2015 (as opposed to February 2016, as asserted by witness Moore). DEQ approved

Duke Energy's request to dispose Riverbend ash at Marshall on June 19, 2015, which did not allow enough time for the Company to accomplish all of the tasks required to utilize Marshall and still meet the 60-day deadline. Once those tasks were accomplished, DEC did begin transporting Riverbend ash to Marshall on July 22, 2015, seven days after DEQ's excavation deadline. Tr. Vol. 24, pp. 93, 108-10, 131-32.

Witness Kerin also clarified that DEC could not have stopped trucking Riverbend ash to the R&B Landfill once it began trucking to Marshall, as the Company was under contract with Waste Management to dispose of the ash at R&B for 17 weeks, or through September 18, 2015, and would have been in breach of contract if it had halted the ash transport before that date. He also stated that the Company's decision to enter into a 17-week contract was based on several factors, including the short turnaround needed for a contractor to truck and accept the ash, and the knowledge that this would be a temporary disposal site and resulting need to find a contractor willing to accept a limited tonnage of ash. Tr. Vol. 24, pp. 110-11.

Finally, witness Kerin noted that Public Staff witness Garrett agreed with the Company that the Inactive Ash Basin and the Old Ash Fill at W.S. Lee needed to be excavated. Witness Kerin disagreed, however, with witness Garrett's assertion that DEC should have delayed excavation of ash material from the Inactive Ash Basin (IAB) and Old Ash Fill at W.S. Lee in order to undertake a grading and slope stabilization project, excavate the overly steep sections of the IAB berm, and dispose of that ash on-site. Witness Kerin testified that this approach would not have been reasonable or prudent and therefore disagreed with witness Garrett's recommendation that the costs associated with transferring ash to Brickhaven ($27,275,192) should be disallowed. Tr. Vol. 24, pp. 93, 111-12, 132.

Witness Kerin testified that, consistent with a Consent Agreement entered into by Duke Energy and the SCDHEC in September 2014, which required excavation of the IAB, the Company excavated ash from this basin and trucked it to the solid waste landfill operated by Waste Management in Homer, Georgia. He explained that, based on available stability analysis, the IAB did not meet the required CCR Rule dam safety factors for maximum storage pool and liquefaction conditions. He concluded that it was therefore reasonable and prudent for DEC to begin excavation immediately. Witness Kerin also noted that at the time the Company was deciding how to manage the IAB, its priority was to address stability and erosion concerns on the river frontage along the IAB dike. He asserted that, due to the low safety factors of the IAB dike, the Company was already limiting equipment access on the dike crests, which limited work to the very narrow portion of downslope area that extended from the dike toe to the river's edge. Witness Kerin asserted further that the equipment necessary to implement witness Garrett's proposal could not have safety traversed the dike on the downslope, and that moving the heavy equipment to the downstream/river side of the downslope would have created undue risk to bank stability and unnecessarily risked worker safety. In addition, while the Company evaluated interim measures that could offer stability and risk mitigation during excavation, these involved work at and in the river to both access and install the features, and the Company decided not to pursue these measures due to the time needed to obtain a USACE permit for work in the river. He noted that the Company had already initiated the IAB's excavation and that by the anticipated 12-month time period to obtain the permit and 4-6 months to install the required features, the basin would be nearly excavated, and the Company would have to later remove the features to restore the river. Witness Kerin maintained that witness Garrett's proposed two-phased approach would not address these issues, would have unnecessarily put worker and environmental safety at risk, and the delay would have been unacceptable to DEC and to the SCDHEC. Tr. Vol. 24, pp. 112-14, 132.

Witness Kerin disagreed with witness Garrett that the Company should have agreed to different terms in the Consent Agreement with SCDHEC. He explained that, based on SCDHEC's expressed concerns, the deadlines agreed to pursuant to the Consent Agreement were reasonable and allowed the Company to achieve the primary goal of the agreement, which was to excavate ash. SCDHEC's concerns were driven by the IAB abutting the Saluda River and the resulting risk of river impacts, the steepness of the banks, and the heavily wooded nature of the slope. He stated that SCDHEC wanted Duke Energy to take prompt action with respect to excavating the IAB, and that desire is reflected in the Consent Agreement and excavation deadlines. Tr. Vol. 24, p. 115.

Witness Kerin also disagreed with witness Garrett that the Company should have delayed excavation of the Old Ash Fill, noting that the Old Ash Fill was also subject to the Consent Agreement and that the SCDHEC was as adamant that the Company excavate this site immediately as it was with regard to the IAB. Tr. Vol. 24, p. 116.

Finally, witness Kerin testified in response to witness Garrett's criticism of DEC's plan to excavate the Structural Fill Area at W.S. Lee in the future, even though witness Garrett did not suggest any disallowances with respect to this plan. Witness Kerin stated that, in order to resolve the concerns of SCDHEC and environmental groups, the Company agreed to mitigate the future risk of operating two ash management structures by managing all ash at W.S. Lee through a single management structure – the landfill – as opposed to taking a piecemeal approach as suggested by witness Garrett. He stated that if the Company was later required to excavate the Structural Fill area after the landfill project was completed, it would incur greater costs than it will incur by managing the ash while the landfill project is ongoing, and that the decision to excavate this area now is reasonable and prudent approach to mitigating against potential future ash related liability and to reduce future costs for the site. Tr. Vol. 24, pp. 93, 116.

Witness Kerin also testified that Public Staff witness Junis' testimony, similar to witness Lucas in the DEP case, incorrectly asserts that the costs of groundwater treatment wells installed at Belews Creek would not have been incurred absent the Sutton Settlement. Witness Kerin asserted that this conclusion ignores the fact that, while the measures undertaken at Belews Creek were reflected in the Sutton Settlement, they were moved up in time from when they would have otherwise been required, and DEC would have installed extraction wells in order to comply with CAMA even without the Sutton Settlement. Tr. Vol. 24, p. 117.

He also disagreed with witness Junis' contention that the Company should not recover the cost of equipment that could remove selenium at Riverbend. He stated that witness Junis' recommendation does not reflect the reality of managing that facility either at the time of that purchase or at present. He explained that in order to excavate the Riverbend ash, as required by CAMA, DEC had to dewater the impoundments, and that the interstitial water treatment system for the dewatering process was designed to meet NPDES permit limits, including selenium. The environmental consultant hired by the Company to develop this treatment system, WesTech, proposed the SeaHAWK bioreactor system for this purpose. Witness Kerin contended that it was imperative for the Company to have a treatment system that could appropriately treat the site's wastewater and meet future permit selenium limits. He stated that, while the SeaHAWK is important to the Company for staying within its permit limits, it is expensive to operate (approximately $60,000/month), and that the Company will only use it when other physical and chemical extraction methods are insufficient. Witness Kerin emphasized, however, the prudency of having this system in place should it be needed, in order to avoid the need to cease ash removal operations in the case that selenium levels increased and the bioreactor was not on site. He offered the example of a five-month delay to secure a bioreactor would cost the Company several million dollars in delay charges under its contract with Charah. He concluded that it was reasonable and prudent for DEC to purchase a bioreactor system to mitigate against potential violations of NPDES permit limits and to treat decanted wastewater at Riverbend, and that the recommended disallowance of those costs should therefore be rejected. Tr. Vol. 24, pp. 90, 117-19, 132.

Witness Kerin also rebutted AGO witness Wittliff's assertion that the Commission should disallow the Company's coal ash costs, and noted that witness Wittliff's testimony appears to go even further in this case than his recommended disallowance in the DEP case. Witness Kerin testified that witness Wittliff's testimony, with its revisionist history approach to coal ash management and his inability to specify or quantify specific disallowances, is not useful to the Commission. Tr. Vol. 24, pp. 91, 133.

Witness Kerin testified that AGO witness Wittliff's contentions that DEC's management of coal ash has lagged behind the rest of the utility industry, and that the Company has ignored dam safety at its facilities, are incorrect. He asserted that DEC's ash management practices have conformed and evolved with changes in industry practices and regulatory standards. He noted that witness Wittliff based his assertion that the Company knew by 2008 that impoundments were no longer the industry standard in part on excerpts from Duke Energy's 10-K filings around that time. He stated that these excerpts, which pertain to Duke Energy and not to individual utilities like DEC, simply notify the Securities and Exchange Commission of potentially significant coal ash costs that Duke Energy anticipated at that time, and potential new regulatory contingencies to which it could become subject, but were not intended to analyze DEC's coal ash management practices and do not support witness Wittliff's claim that the Company's coal ash management practices were out of step with industry or that the Company knew of any such inconsistency. Witness Kerin also stated that while the 1988 and 1999 EPA Reports cited by witness Wittliff in support of his position show increases in the percentages of new lined landfills and surface impoundments, witness Wittliff acknowledged that the Company last constructed a new ash basin in 1982. In addition, while these reports show an increase in the percentage of basins that were lined from 17 to 28% between 1975 and 1995, 28% is still a minority of new basins being constructed, which is consistent with DEC's practice during this time frame. Witness Kerin stated further that witness Wittliff's assertion fails to account for site-specific conditions, which as the EPA explains in the preamble to the CCR Rule and guidance, is an essential consideration when making CCR unit-specific determinations. Finally, he pointed out that witness Wittliff presented no credible evidence to show that the Company's engineering and design of its impoundments was not consistent with industry practice and regulatory requirements at the time. Tr. Vol. 24, pp. 119-21.

Witness Kerin also rebutted witness Wittliff's assertion that DEC should have built new lined impoundments as opposed to expanding existing unlined impoundments. He testified that witness Wittliff's argument ignores the fact that construction of new lined impoundments would have entailed significant expense to the Company, while not removing the need to maintain existing unlined impoundments. In addition, because such action would have occurred before it was consistent with industry standards, it would have put the Company at risk of disallowance of those costs. Witness Kerin stated that the suggestion that DEC chose not to construct new lined impoundments in order to delay and avoid potential exposure to requirements for more rigorous environmental standards is therefore not only unfounded but also inconsistent with the realities of managing coal ash basins. He noted that, at the hearing in the DEP proceeding, witness Wittliff admitted that the majority of utilities in the country continued to use unlined, wet ash impoundments well after the timeframe in which he alleges the Company should have ceased to do so, because the law allowed them to do it, and the law continued to allow them to do it. Witness Kerin noted the inconsistency between admitting that the Company's use of unlined, wet basins was legal and in line with most utilities in this country, and asserting that DEC was imprudent by doing so. Tr. Vol. 24, pp. 121-22.

Witness Kerin also responded to witness Wittliff's contention that dam safety has not been a priority for the Company, and stated that DEC has a very robust dam safety program, led by a central organization with responsibilities for each site in the system. The program includes weekly documented inspections, and tracking of any corrective actions, as well as episodic inspections to be conducted following heavy rain events or certain seismic events. He stated that the Company also conducts detailed, documented annual inspections of each facility, and that any issues identified are tracked through to resolution. He noted in addition that the Company internally inspects and documents basin discharge piping annually, and again tracks identified issues through to resolution. Any required modifications are managed through a stringent program including plans and specifications submitted to and approved by DEQ's Dam Safety Program. This is all in addition to DEQ's own annual inspections of the basins and all completed modification projects. He stated that the Company provided five-year dam safety inspections dating to the 1970s. He maintained that no instance arose in which the Company failed to act upon a major dam safety issue. He argued that subsequent mentions of certain issues simply show that DEC was monitoring the condition before identifying or confirming the need for longer- term repair, and that these inspections do not show any major issue that threatened the integrity of the dam's ability to retain the ash in the basin. Tr. Vol. 24, pp. 122-24.

Witness Kerin responded to witness Wittliff's criticism of witness Kerin's own CCR experience and qualifications to discuss ash management industry standards, noting the irony of witness Wittliff's position in light of his own limited experience in this area. Tr. Vol. 24, p. 124.

Witness Kerin also testified that, like his testimony in the DEP case, CUCA witness O'Donnell's analysis and recommendation of a 75% disallowance of the Company's coal ash costs relies on multiple analytical flaws that are fatal to his conclusion, and that witness O'Donnell made little effort to address those flaws in his conclusions from the earlier case. Specifically, witness Kerin disagreed with witness O'Donnell's conclusion that his national comparison of CCR assets retirement obligation, or ARO, amounts shows that the Company's ARO is overstated by 75%. He stated that witness O'Donnell appears not to have considered 23 factors that must be accounted for in order to seriously attempt this type of analysis. He also stated that witness O'Donnell made no attempt to quantify DEC's coal ash AROs resulting from CAMA, as compared to its obligations under the CCR Rule, or to determine the impetus for coal ash AROs for the other utilities to which he compares the Company. Witness Kerin argued that witness O'Donnell cannot credibly testify that the Company's ARO coal ash costs are higher because of CAMA when he cannot attribute any specific ARO coal ash costs to CAMA or attribute ARO coal ash costs for other companies to any particular regulatory obligation. He explained that, even if witness O'Donnell had conducted such an analysis, it would not provide an accurate comparison, because other utilities are in very different stages of their coal ash management timeline than DEC. Witness Kerin also maintained that the SNL data relied upon by witness O'Donnell are rough estimates, and that there is substantial uncertainty over the level of actual closure costs for many of those utilities he listed. Witness Kerin therefore recommended that the Commission consider the reasonableness of the Company's ARO amount on its own merits, based on the facts of this case, and without regard to witness O'Donnell's proposal. Tr. Vol. 24, pp. 90, 125-28, 133.

Finally, witness Kerin disagreed with Sierra Club witness Quarles' assertions as to the consistency of DEC's coal ash management practices with industry, the costs of lined landfills as compared to surface impoundments, and Duke Energy's previous pursuits of reuse options for ash. Tr. Vol. 24, p. 91. For the same reasons he presented in response to witness Wittliff's testimony, witness Kerin disagreed with witness Quarles' conclusion that operation of unlined basins after the 1980s was unreasonable, and countered that witness Quarles does not appear to have considered industry standards or regulatory requirements or, like witness Wittliff, to have presented any specific evidence that the Company's impoundment engineering and design was not consistent with industry practice and regulatory requirements at the time. He also testified that witness Quarles' assertion that closure costs for surface impoundments were higher than costs for lined landfills fails to consider the additional costs associated with conversion to lined landfills, in addition to the fact that DEC last constructed a new basin in 1982. Finally, witness Kerin clarified that the Company did make sales of coal ash for reuse during the 1980s, from Marshall in 1986 and Belews Creek in 1988, contrary to witness Quarles' assertion otherwise. Tr. Vol. 24, pp. 128-29, 133-34.

2. Wright

On rebuttal, Company witness Wright testified to several issues related to the recovery of costs associated with coal ash remediation expenses raised in the testimonies of Public Staff witnesses Garrett, Moore, Junis, and Maness, AGO witness Wittliff, and CUCA witness O'Donnell. He stated that, overall, the theories underlying these witnesses' recommended disallowances of these costs are unfounded, do not provide a proper basis on which costs may be disallowed, and should be rejected by the Commission. Tr. Vol. 12, pp. 156-2-3, 161-62.

Witness Wright first disagreed with Public Staff witness Junis' recommendation to disallow approximately 49% of the Company's remaining coal ash costs after accounting for certain other disallowances that he and Public Staff witnesses Garrett and Moore recommend. Witness Wright stated that this recommendation does not align with the appropriate regulatory standard for denial of cost recovery, which he explained is a finding that specifically identified costs are imprudent or unreasonable. He noted that witness Junis did not find the Company imprudent for most of the coal ash-related cost, nor did witness Junis find the Company's costs to be unreasonable. Instead, witness Wright explained, witness Junis asked the Commission to disallow these costs apparently based on the theory that the Company acted poorly in its historical coal ash disposal methods and on speculation of past or future environmental compliance issues.

Witness Wright maintained that it is not proper for the Commission to deny cost recovery based on speculation of future findings of violation, or to impose a sharing of costs based upon an undefined culpability standard. Tr. Vol. 12, pp. 156-4, 162-63.

Witness Wright also explained that the proposed sharing of cost is inconsistent with Commission precedent and with the Public Staff's own position on the recovery of coal ash disposal cost in Dominion's 2016 base rate case. In that case, he recalled, Dominion requested a recovery of CCR Rule compliance costs up to and through 2016. He explained that those expenditures included closure and related costs for the Chesapeake Energy Center, even though a court found past violations of the Clean Water Act at this location. He stated that the Commission concluded that the recovery of these costs, as provided in the stipulation entered into in that case by the Public Staff and Dominion, was just and reasonable. He stated his opinion that the CCR cost recovery methodology applied in the Dominion case was correct and should be applied in the same way for DEC. Tr. Vol. 12, pp. 156-12, 163.

Witness Wright also testified that the Public Staff's suggestion that the Commission's treatment of abandoned nuclear plants supports its proposed cost sharing proposal is not appropriate, because abandoned nuclear plant costs are not comparable to CCR costs. He explained that the Commission has found abandoned nuclear cost not to be used and useful, and thus not eligible for rate-based treatment. In contrast, he noted, the coal plants associated with these costs and the related coal ash disposal facilities have been used and useful in providing low-cost, reliable power to North Carolina customers for more than 70 years, and will continue to be used and useful. He stated that this is consistent with the recent Dominion case, where the Commission found that CCR repositories were and continue to be used and useful, were therefore not abandoned, and were therefore eligible for recovery through amortization and a return on the unamortized balance, similar to other types of used and useful property. Tr. Vol. 12, p. 156-16 – 156-19.

Witness Wright proceeded to state that the Commission's treatment of environmental cleanup of manufactured natural gas (MNG) plants also does not support the Public Staff's proposed cost sharing, and referred to his direct testimony that MNG plant costs differ from coal ash disposal costs, both in terms of the time that elapsed between the actual usage of the facility and the environmental-related cost recovery, and in terms of ownership. In addition, he noted that MNG facilities, like abandoned nuclear plants, were found not to be used and useful. He noted further that there is no need to rely on a 23-year-old cost recovery example from a different industry, dealing with assets last used more than 70 years ago, when the best example of the Commission's treatment of coal ash disposal costs can be found in the Dominion case that was decided one year ago. Tr. Vol. 12, p. 156-18.

Witness Wright also testified that the 25-year amortization period proposed by the Public Staff is not justified by their cost sharing theory, which is based on a culpability theory and by defining these costs as being extremely large. He explained that adoption of this proposal would undermine the basic cost of recovery principles embodied in the North Carolina utility regulation and would subject utilities to an unknowable and ill-defined cost recovery standard. He explained further that it could also result in a perception of the State's utilities as riskier, leading to higher cost of capital and cost of service. Tr. Vol. 12, p. 156-22.

Witness Wright disagreed with witnesses who claimed that Duke Energy substantially caused the CCR Rule and CAMA and that, therefore, all costs incurred to comply with these requirements should be disallowed. He referenced his direct testimony that while the timing of CAMA may have been influenced by the Dan River accident, he cannot conclude that the North Carolina legislature would have adopted a different substantive law without Dan River. He noted in addition that there are numerous examples of North Carolina lawmakers and regulators adopting environmental policies, not only specific to this state, but stricter than national or neighboring states' policies. He also noted that state-specific actions to address CCRs have been adopted in a number of jurisdictions. Based on all these factors, he opined that North Carolina likely would have adopted a state-specific CCR regulation regardless of the Dan River accident. Tr. Vol. 12, pp. 156-24 – 156-27, 163-64.

Witness Wright also argued that CAMA was not intended to be a punitive law. He stressed that CAMA does not contain any punitive limitation on cost recovery except for the provision for certain spills to surface water. He also noted that attempts to further restrict coal ash disposal cost recovery under this law have been tried three times, but in all three cases, amendments or laws to disallow cost recovery were defeated. He stated that the General Assembly has shown that it will, when it wants to, adopt specific cost recovery restrictions with other state environmental laws, as exemplified by the Clean Smokestacks Act. In contrast, he explained, the legislature's affirmative decision not to disallow prudently-incurred costs related to CAMA, and not to adopt subsequent proposals to disallow such costs, indicates that CAMA was not meant to be punitive with regard to cost recovery, but rather intended to leave cost recovery determinations to this Commission's oversight and sound regulatory policy. Tr. Vol. 12, pp. 156-28 – 156-31, 164-65.

With regard to coal ash litigation costs, witness Wright reiterated that DEC has excluded from its recovery request all fines, penalties, and fees related to the Dan River accident. Tr. Vol. 12, p. 156. He also opined, however, that witness Junis' apparent position that all of the Company's costs to defend lawsuits should be disallowed recovery, regardless of whether the Company is ultimately found liable or not, is not supported by precedent or sound regulatory policy. First, the Glendale Water case does not support this theory. In addition, he noted that the Commission has recognized that settlements and litigation defense costs, when reasonable and prudent, are recoverable costs, and that the Commission and the Public Staff have also recognized that settlements are beneficial. Tr. Vol. 12, pp. 156-31 – 156-36, 165.

Witness Wright disagreed with the Public Staff's recommendation of provisional cost recovery for coal ash expenditures prudently incurred from January 2015 through August 2017, based on the argument that the appropriateness of such recovery may depend on the outcome of legal determinations. He noted first that this would appear to be retroactive ratemaking. He also stated that the standard is that the utility makes the best possible decisions on expenditures based on the information available at the time, and determinations of the reasonableness and prudency of these costs should not depend on future outcomes of legal proceedings but what was known or knowable at the time. Tr. Vol. 12, pp. 156-39 – 156-40, 165.

Additionally, witness Wright disagreed with Junis' recommendation that costs to remedy environmental violations where the costs exceed what CAMA would have required be disallowed, including those specifically related to Belews Creek groundwater extraction and treatment and a second related Riverbend selenium removal. Witness Wright, citing to his earlier testimony, stated first, that absent a finding that the Company was guilty or had liability associated with environmental issues that led to additional compliance costs, or that the settlement in question Junis was citing to was imprudent, that environmental costs like the Belews Creek costs noted here should be recovered from ratepayers and not shareholders. Secondly, in regard to Junis' statements that DEC had a duty to comply with groundwater rules, and its failure to comply are a reason to deny the recovery of these costs with or without settlement, witness Wright cited his earlier testimony where he discusses how and why unlined coal ash pond exceedances occur and are not unexpected. Moreover, witness Wright noted his earlier testimony in explaining why witness Junis' theory that DEC had a duty to comply with the North Carolina groundwater rules, Title 15A, Subchapter 2L of the North Carolina Administrative Code (2L rules), without regard to whether it followed accepted industry practices, is misplaced. Tr. Vol. 12, pp. 156-36 – 156-38, 162.

Next, witness Wright stated that he disagreed with CUCA witness O'Donnell's belief that the DEC was responsible for the passage of CAMA and should be responsible for any coal ash costs above that required by the CCR Rule, and cited to his earlier statements disagreeing with such. Witness Wright opined that the Commission should reject witness O'Donnell's recommendation that the Company's environmental compliance costs should be disallowed based on a comparison of the alleged national asset retirement obligations, or ARO, amounts relating to CCRs. He stated further that witness O'Donnell's analysis neither considered the fact that most utilities are behind DEC from a timing perspective in both planning and addressing coal ash pond closure, nor reflected the most recent coal ash CCR costs being reported by various electric utilities. Witness Wright also disagreed with witness O'Donnell's statement that the EPA's reconsideration of aspects of its CCR Rule "direct[ly] conflict[s]" with witness Wright's statements about this country's ever-tightening environmental standards. Witness Wright stated that although it was possible that the EPA could modify its current rule, there is no way for DEC to know if, when, or how such modification might occur. Tr. Vol. 12, p. 156-40 – 156-43.

Finally, witness Wright testified that the Commission should reject AGO witness Wittliff's recommendation that because the Company had a "history" of regulatory violations, and due to the Dan River accident leading to the enactment of CAMA, DEC should be disallowed recovery of coal ash related costs. In reference to his earlier statements on CAMA and his direct testimony, witness Wright reiterated his belief that the North Carolina legislature would have adopted some type of state specific coal ash closure legislation shortly after the passage of CCR, regardless of the Dan River accident. He noted that witness Wittliff did not quantify the disallowance he recommends, but instead assumed that the costs incurred to comply with both the Federal CCR rules and CAMA were unreasonable or imprudent without any underlying support. Additionally, witness Wright identified that witness Wittliff's recommended disallowance was also at odds with his testimony filed in the DEP case. Tr. Vol. 12, pp. 156-43 – 156-44, 163-64.

At the hearing, witness Wright explained in response to questions by counsel for the Sierra Club that, if the Commission approved the Company's request for recovery of ongoing expenses, the Company would then bring its actual costs to the Commission for review and approval annually. Tr. Vol. 12, p. 186. Witness Wright also explained in response to questions regarding EPRI documents from the 1980s that those reports acknowledged that more information was being provided about potential impacts from coal ash, but that the reports also advised that disposal procedures not yet be modified. Id. at 191-92. During cross by counsel for NC WARN, he discussed the decision tree that the Commission uses to determine whether costs are recoverable and how that recovery will occur. Witness Wright explained that the first question is whether the costs were reasonable and prudent in providing service to ratepayers and, if so, the next question is whether they were used and useful and, if so, the last stage is to consider what outcome would be fair and equitable. Witness Wright explained further that it is at the last stage where the Commission has leeway to consider different rate designs to achieve a fair and equitable result. Id. at 202-06.

Witness Wright testified in response to questions by counsel for the Public Staff that the fact that DEC has an exceedance or even a violation is not indicative or necessarily tied to the recoverability of costs DEC is seeking in this case. Witness Wright explained that if DEC has a violation and admitted wrongdoing, or an adjudicated proceeding determined there was wrongdoing, those costs or fines should not be recovered. Witness Wright testified that that is different from DEC having to now comply with new standards; in terms of costs associated with new obligations, he considers those long-term compliance costs. Tr. Vol. 13, pp. 77-78, 91-93. On redirect, witness Wright agreed that it is reasonable to assume that state and federal regulators who understood how soil and water interact with each other would have passed appropriate rules and regulations over time to account for that interaction. Tr. Vol. 13, pp. 95-96.

In response to questions by the Chairman, witness Wright confirmed that, in his opinion, the Commission's primary responsibility pertains to cost recovery rather than regulating how utilities implement state and federal environmental laws, and agreed that DEQ was the agency in charge of approving coal ash remediation plans. Witness Wright also agreed that the Commission is not a court of general jurisdiction, and that it determines the reasonableness and prudence of utility decisions rather than make cost recovery decisions by following a duty of care or any other standard available in tort or other type of law. Witness Wright confirmed that this standard does not consider what could or should be anticipated into the future, but considers what is reasonable and prudent given the information known now. Tr. Vol. 13, pp. 99-102.

3. Wells

Company witness Wells testified on rebuttal to the different approach taken by the Public Staff in this case from the DEP case. In the DEP case, the Public Staff attempted to characterize DEP's compliance with its NPDES permits as poor. In this case, witness Junis did not discuss DEC's compliance with NPDES permit requirements, which witness Wells noted has been outstanding, but rather suggested that the existence of seepage at the Company's CCR impoundments is evidence of the Company's "culpability." Witness Wells explained that the Public Staff's position ignores (1) the fact that the EPA first directed permitting authorities to address seeps in 2010, (2) the Company's attempts to obtain regulatory certainty as to seeps, and (3) DEQ's challenges in implementing EPA's direction. Tr. Vol. 24, p. 226.

Witness Wells testified that Public Staff witness Junis' negative characterization of DEC's compliance record is not justified by the historical record. Tr. Vol. 24, p. 224. He explained that exceedances of groundwater standards and the existence of seeps in the vicinity of the Company's ash basins do not indicate mismanagement or poor compliance programs. Witness Wells stated that the existence of groundwater exceedances at or beyond the compliance boundaries at DEC sites is rather a function of where these sites are on the timeline of groundwater assessment and corrective action under modem laws that have changed the way unlined basins are viewed. Witness Wells testified that the Company's decision to use unlined basins to treat ash transport water was reasonable and consistent with the approach consistently employed across the power industry at the time that the basins were built. Witness Wells noted that each DEC site had been properly and legally operating an unlined basin for at least a decade before the adoption of any regulatory requirements related to groundwater corrective action. Witness Wells noted further that as requirements changed over time, DEC has taken every action required by DEQ's groundwater rules, and later by CAMA and the federal CCR Rule, to address groundwater impacts as they have been identified. Tr. Vol. 24, pp. 227-29, 236, 258.

Witness Wells opposed the suggestion that DEC only engaged in comprehensive groundwater monitoring and remediation when forced to do so by CAMA and other developments. He explained that the Company began monitoring groundwater at Allen in 1978, Belews Creek and Marshall in 1989, Dan River and W.S. Lee Steam Stations in 1993, and the remaining sites in or around 2006. He noted that, in 2011, DEQ prescribed a process to be undertaken by DEQ and utilities upon the identification of a groundwater exceedance near a coal ash pond, which included performance of an assessment to determine the cause of the exceedance and, as necessary, develop a Corrective Action Plan consistent with North Carolina groundwater rules. He stated that under that process, only after a utility failed to undertake corrective action when directed to do so would DEQ consider pursuing enforcement. He noted that, contrary to witness Junis' testimony, all of this activity predates the threat of litigation by environmental groups, the DEQ enforcement suit, the Dan River spill, and CAMA. He also testified that, as witness Junis' testimony and exhibits demonstrate, DEC has always promptly responded to any concerns raised by the relevant regulatory entities and where necessary, implemented appropriate corrective action steps to remedy any issue. He stated that the Company has proactively sought consent orders and written agreements to ensure alignment with the regulatory agency as to appropriate scope and timing of additional investigation and corrective action. Tr. Vol. 24, pp. 230-31, 234-36, 259-60.

Witness Wells disagreed with witness Junis' apparent contention that DEC should have moved well ahead of accepted science, regulatory requirements, and industry practice and begun taking measures to prevent any and all groundwater quality issues without regard to the cost of those measures or whether sufficient and proven technology existed at the time to address the conditions at the site. He explained that the papers cited by witnesses Junis, Wittliff, and Quarles discussing potential issues associated with coal ash disposal, and the importance of developing and implementing appropriate controls, highlight the evolving state of knowledge regarding the risks and best practices related to coal ash disposal management, rather than condemn the use of unlined basins. Tr. Vol. 24, pp. 232-34, 258-59.

Witness Wells also testified that North Carolina's groundwater laws were not intended, as witness Junis contends, to be punitive. While he agreed that the groundwater rules require corrective action without regard to fault, he disagreed with witness Junis' conclusion that responsibility for corrective action is equivalent to any other violation of the law. He stated that the record in this case clearly demonstrates that groundwater contamination resulted from DEC's otherwise lawful use of unlined ash basins in furtherance of its mission to provide low cost electricity, and that the use of ash basins was an accepted and reasonable practice conducted with DEQ and EPA oversight. He explained that, for historical sites such as those at issue in this case, this State's groundwater regulations and the DEQ's practices and policies, as well as the CCR Rule, are focused on environmental protection rather than culpability, that the required corrective action is based upon science and not an assessment of wrongdoing. He stated that, in evaluating Corrective Action Plans, DEQ considers numerous factors, including the extent of any threat to human health or safety, impact on the environment, available technology, potential for natural degradation of the contaminants, and cost and benefits of restoration. He concluded that, if the utility cooperates with DEQ, the applicable law and policies are designed to drive corrective action rather than enforcement action, and he saw no intent for those law and policies to be used to deny cost recovery in regulatory proceedings. Tr. Vol. 24, pp. 237-38, 260.

Witness Wells also stated that witness Junis' characterization of groundwater violations under the 2L rules ignores the iterative nature of comprehensive site assessment. He noted that measuring exceedances at different locations in a plume around an activity may result in multiple exceedances of groundwater standards, but that measurement does not result in multiple violations of the 2L rule's prohibition. He explained that this distinction is important for evaluating the claim that the number of exceedances indicates a "breadth of environmental violations." He stated that it would be more accurate to say that, at seven sites, DEC has lawfully operated ash basins that, after decades of use, resulted in exceedances of groundwater standards at those sites. He pointed out how Duke Energy's coal ash basins are some of the most studied sites in North Carolina, with more than 1,400 groundwater monitoring wells, and that the number of exceedances presented by witness Junis signifies therefore the thoroughness of the evaluation rather than a number of groundwater violations. Tr. Vol. 24, pp. 238-40, 260-61.

Witness Wells also explained that the extraction and treatment activity required by the Sutton Settlement, which costs witness Junis recommends for disallowance, is work that the Company simply agreed to perform earlier than required under the CCR Rule and CAMA in order to address offsite groundwater impacts. Tr. Vol. 24, pp. 241, 260.

Witness Wells also disagreed with witness Junis that the amount of litigation regarding the Company's ash basins suggests that the Company was imprudent in managing ash. He opined that the amount of litigation has been driven by nongovernmental organizations that have been pressing for complete excavation of ash from all basins across the Southeast. He stated that DEC has appropriately been opposed to this, arguing instead that final closure methods should be dictated by the CAMA process and a site-specific balancing of net environmental benefits of various closure options based on science, regulatory policy, and the best interest of the Company's customers. He stated that the positions of the NGOs and the suits do not themselves indicate imprudence. Rather, he explained, the appropriate closure methodology must take into consideration the particular characteristics of each site. He stated that the EPA and North Carolina agree and that, consistent with this principle DEC has settled cases where science and engineering supported closure by excavation, and continues to vigorously litigate cases where other closure methods are more or equally protective of the environment at less cost. He concluded that the volume of filed litigation on its own should not factor into the Commission's determination of whether the Company's CCR costs were prudently incurred. Tr. Vol. 24, pp. 242-44.

Witness Wells also disagreed with the Public Staff's suggestion that any exceedance or violation of water quality regulations, no matter how minor or how long ago, leads to the denial of cost recovery for any activity that acts to "cure" the impacts of the violation. He reiterated that not all exceedances of the 2L standards amount to a violation that requires corrective action under the 2L rules. He also stated that even when an exceedance requires corrective action, the groundwater rules do not treat the exceedance the same way as, for example, the Clean Water Act treats an exceedance of an NPDES permit limit. When the latter is violated, he explained, the permittee is immediately subject to a notice of violation (NOV) and penalty, and must ensure the next discharge complies with the permit limit or risks a new NOV and escalating penalty. He contrasted this with groundwater standards, under which an exceedance does not immediately result in an NOV and penalty. Instead, he explained the owner/operator must report the exceedance and work with DEQ to determine whether it was due to permitted activity, assess the extent of the exceedance, and undertake corrective action. Any newly measured exceedances do not require a further site assessment and do not result in additional or escalating penalties, but are actually expected as additional assessment prior to corrective action is conducted. He testified that the 2L Rules' corrective action provisions are deliberately designed around the idea that older facilities, built before liners were a regulatory obligation, were likely to have associated groundwater impacts, that such impacts were not the result of regulatory noncompliance, and that they should be addressed in a measured process. He concluded that compliance with this process is not mismanagement and should not be held against DEC with respect to cost recovery. Tr. Vol. 24, pp. 244-46.

Witness Wells also addressed seeps. He explained that all earthen impoundments seep, and that DEQ's dam safety regulations acknowledge this.. He stated that EPA first directed permitting authorities to address seeps in 2010, and at that time, the Company engaged DEQ to determine the appropriate approach to address seeps and began including them in permit applications. He asserted that DEQ did not consider seeps to have a significant environmental impact. He also maintained that EPA and DEQ did not appear to agree on the appropriate approach to address seeps. He maintained that, absent the CCR Rule or CAMA, the existence of seeps in a basin would not on its own automatically trigger basin closure and should not, therefore, impact the Company's ability to recover its CCR environmental compliance costs. He asserted that, although closing basins would be one way to address seeps, it would be the most drastic of several possible remedies, and both EPA and DEQ have stated that seeps can be addressed by permitting or rerouting, among other options. Tr. Vol. 24, pp. 246-50, 261.

Accordingly, Witness Wells explained, DEC entered into a special order by consent (SOC) with DEQ to address seeps at the Allen, Marshall, and Rogers (formerly Cliffside) stations. He explained that the SOC provides regulatory clarity and certainty as to the appropriate monitoring frequency, parameters to be sampled and limits with respect to the non-engineered seeps, while requiring the Company to accelerate the schedule for decanting water from the basins, a process that is expected to substantially reduce or eliminate seeps. He further testified that DEC is working with DEQ to develop additional SOCs based on this model to address non-engineered seeps at the remainder of DEC's and DEP's impoundments. He clarified that the SOC requirements to accelerate decanting do not create additional costs for the Company over and above the cost to complete these activities in compliance with CAMA and the CCR Rule. In sum, witness Wells testified that the application for and execution of SOCs to address seeps is not evidence of DEC "culpability," but rather a regulatory mechanism to provide clarity and alignment with respect to scope and schedule for compliance-related activities given a change in circumstances, such as a change in requirements or in operations. Tr. Vol. 24, pp. 251-53, 261.

Finally, witness Wells disagreed with witness Junis' suggestion that DEC caused the creation and adoption of the CCR Rule. He testified that the environmental regulatory regime is an ever-evolving body of law, and the EPA engaged in more than two decades of studies before it finally issued a proposed CCR Rule in 2010. Through this process, he noted, the EPA identified 150 cases in over 20 states involving over 25 utilities and government facilities that involved groundwater damage with at least a potential link to coal ash; but determined that immediately closing basins, which would require shutting down operating coal plants, would be more harmful than taking a measured approach. Tr. Vol. 24, pp. 254-55, 261-62.

At the hearing, in responding to questions by counsel for the Sierra Club, witness Wells responded that the Company did engage in voluntary analysis of its coal ash sites prior to DEQ requirements to do so, as far back as the 1970s at Allen, and determined based on those analyses that no significant impacts to groundwater were occurring, and no significant risk to groundwater going forward. Tr. Vol. 25, pp. 36-37.

In response to questions by the Commission, witness Wells confirmed that while the AGO and Public Staff presented documents in this case addressing the Company's actions going back to the 1950s, the AGO took no action itself with regard to coal ash management until 2014, when the AGO became involved with citizen suits. He opined that the reason for that inaction was that the Company's actions with regard to coal ash were acceptable from a regulatory perspective until much more recently. Tr. Vol. 26, pp. 72-73. He also stated that DEC's recent comprehensive studies of the groundwater surrounding the Company's ash basins conducted pursuant to CAMA have confirmed that, while groundwater has been impacted, there is no evidence of any current or likely future impacts to, for example, off-site drinking wells or other receptors at any of the seven sites, and have validated the Company's measured approach to coal ash management in previous years. Id. at 77-80. He confirmed that the Company currently has installed wastewater treatment equipment where needed at all of its basins to comply with CAMA. Id. at 82-83.

In response to questions by the Chairman, he further confirmed that, absent other considerations, there are a number of remedies to address a seep that could be applied rather than to excavate the basin. Tr. Vol. 26, pp. 85-88. He also stated that substances such as iron, manganese, and pH are classified by the EPA as secondary maximum contaminant levels which are regulated based on aesthetics (e.g., taste, odor, etc.) and are not considered health risks. Witness Wells acknowledged that some recent studies have suggested that exposure to extremely high levels of manganese could pose a health risk, but explained that, typically, those levels are orders of magnitude above where the limit was set for aesthetic purposes. Id. at 88-91. Finally, he addressed the difficulty of monitoring groundwater impacts, especially when dealing with naturally occurring elements, and explained that a single monitoring well is a snapshot of that particular area at that point in time, and that conditions 100 yards away could be very different, yet still be naturally occurring. He stated that this is why the Company's efforts to monitor a large area is an iterative process. Id. at 91-93.

4. McManeus

On rebuttal, witness McManeus responded to witness Maness' proposed adjustments regarding coal ash pond closure costs. She explained that there were two main adjustments, to remove ongoing environmental costs and adjust deferred environmental costs, as listed in Boswell Exhibit 1, Schedule 1, and based upon seven specific adjustments proposed by witness Maness. Witness McManeus explained that although the Company disagrees with the majority of the Public Staff's seven proposed adjustments, it does not disagree with witness Maness' third or fourth adjustments. Witness Maness' third adjustment is to add a return on the deferred balance up through the expected date of new rates in this proceeding. The fourth adjustment is to calculate the return using a mid-month convention rather than a beginning-of-month convention. Tr. Vol. 6, pp. 312-14, 357-58.

In regard to witness Maness' second adjustment recommending that the costs DEC has identified as "CAMA only" be allocated based on an allocator that allocates to all jurisdictions, witness McManeus explained that the Company has identified very specific cost categories that should be treated as an exception to the general allocation rule that costs of a system be borne by all of the users of the system. Witness McManeus explained that these costs are unique to North Carolina and that such an exception is consistent with other examples where the Commission has allowed direct assignment to North Carolina, and cited to the cost allocation methods used in regard to the North Carolina Renewable Energy and Energy Efficiency Standard and the Clean Smokestacks Act. Witness McManeus further explained that the Company disagreed with witness Maness' first, fifth, sixth, and seventh proposed adjustments, and that such adjustments were addressed by other Company witnesses' testimony. Tr. Vol. 6, pp. 312-16, 357-58.

Witness McManeus rebutted the Public Staff's recommendation to exclude the deferred coal ash balance from rate base, and indicated that, to the contrary, it was appropriate for that balance to remain in rate base and for the Company to earn a return on it. She indicated that while witness Doss approached this issue from an accounting perspective, from her viewpoint it was important to recognize that rate base represents the amount of funds supplied by investors. Such funds have been advanced for many purposes, including construction of electric plant, but, she stated, there are other purposes as well – for example, to purchase fuel inventory or to provide cash working capital, etc. Tr. Vol. 6, p. 317. In this particular case, she indicated, investors have advanced funds to pay for coal ash compliance costs, and it is therefore appropriate for the Company to be allowed a return on the deferred coal ash balance during the period for which the Company will amortize and collect these amounts from its customers, as the Company will continue to incur financing costs on the balance of funds that is uncollected. Id. She added that the characteristic that makes the deferred coal ash cost a legitimate component of rate base is the fact that the funds used to pay those costs were supplied by investors. Id. at 318.

Lastly, witness McManeus addressed witness Maness' statement that expenses of operating and maintaining property in rate base in the present or in the future "are allowed to be recovered from the ratepayers on an ongoing basis as operating expenses." Agreeing with his statement, she explained that this is the principle underlying the Company's proposal for recovery of the ongoing annual coal ash basin closure costs, what witness Maness terms the "run rate." Witness McManeus stated that these ongoing compliance costs are no different from other ongoing and recurring expenses the Company incurs in the test year, and that such costs are equivalent to the Company's reasonable and prudent test year coal ash basin closure spend. She further explained how the Company's proposed recovery of these ongoing compliance costs through rates would be subject to true-up in subsequent rate cases so that only actual costs are recovered. In conclusion, witness McManeus cited to Chairman Finley's statements in the recent DEP rate case proceeding that a rider could be an alternative mechanism for cost recovery of on-going compliance costs, and stated that the Company agrees that a rider would be an appropriate alternative mechanism to recover such costs. Tr. Vol. 6, pp. 315-16, 357-58.

5. Doss

Witness Doss rebutted the Public Staff's positions regarding ARO accounting that the Company employed for its deferred coal ash compliance costs, and, in particular, witness Maness' characterization of those costs as a deferred expense. Witness Doss provided a detailed explanation of the GAAP and FERC accounting rules with respect to the ARO established in connection with the Company's coal ash basin closure obligations, as well as the deferral orders issued by the Commission in Docket No. E-7, Sub 723. Tr. Vol 12, pp. 61-71. He noted that the Company had simply accounted for these costs as required under GAAP and FERC Uniform System of Accounts, and had deferred the impacts of ARO accounting, as authorized by the Commission's deferral orders. Id. at 70-71.

Witness Doss also responded to witness Maness' opinion that coal ash costs should not be classified as "used and useful" costs. He indicated that, to the contrary, under GAAP and FERC accounting guidance, the asset created when a Company initially recognizes an ARO is considered part of the property, plant and equipment for the assets which must be eventually retired. Id. at 71. He noted further that such costs are used and useful in that they are intended to provide utility service in the present or in the future through achieving their intended purpose: environmental compliance, the retirement of the ash impoundments and the final storage location for the residuals from the generation of electricity, and that the achievement of those three purposes is used and useful as the utility has the obligation to comply with CAMA and the CCR Rule. Id. at 73.

Commission Determinations

General Cost Recovery Principles

A central operating principle underlying utility rate regulation in North Carolina (and virtually all other jurisdictions) is that the utility's costs are recoverable in rates. As two of the leading modern commentators on utility regulation put it in the opening paragraphs to a chapter (titled "The Role of the Revenue Requirement") in their treatise on utility regulation:

> No firm can operate as a charity and withstand the rigors of the marketplace. To survive, any firm must take in sufficient revenues from customers to pay its bills and provide its investors with a reasonable expectation of profit .... Regulated firms are no exception. They face the same constraints ....
>
> A basic concept underlying all forms of economic regulation is that a regulated firm must have the opportunity to recover its costs. ... Without the opportunity

> to recover all of its costs and earn a reasonable return, no regulated private company can attract the capital necessary to operate.

Jonathan A. Lesser & Leonardo R. Giacchino, Fundamentals of Utility Regulation 39 (Pub. Utils. Reports, Inc., ed., 2007) (Lesser & Giacchino).

Lesser & Giacchino refers to the concept of cost recovery as the "revenue requirement" (id.), and the North Carolina Supreme Court has also acknowledged its central role in utility ratemaking. See, e.g., State ex rel. Utils. Comm'n v. Thornburg, 325 N.C. 484, 490, 385 S.E.2d 463, 466 (1989) (Thornburg II) and State ex rel. Utils. Comm'n v. Thornburg, 325 N.C. 463, 467 n.2, 385 S.E.2d 451, 453 n.2 (1989) (Thornburg I), in which the concept is stated to be embedded in the statutory rate making formula, and, indeed, expressed formulaically:

> This statute [N.C. Gen. Stat. § 62-133] requires the Commission to determine the utility's rate base (RB), its reasonable operating expenses (OE), and a fair rate of return on the company's capital investment (RR). These three components are then combined according to a formula which can be expressed as follows:
>
> (RB x RR) + OE = REVENUE REQUIREMENT

Costs are not recoverable simply because they are incurred by the utility. The utility must show that the costs it seeks to recover are (1) "known and measurable"; (2) "reasonable and prudent"; and (3) where included in rate base "used and useful" in the provision of service to customers. Lesser & Giacchino, at 41-43. But once it has shown that these metrics are met, the utility should have the opportunity to recover the costs so incurred. This is what North Carolina's ratemaking statute requires (see N.C. Gen. Stat. § 62-133(b)(5)), and to do otherwise would amount to an unconstitutional taking.

In this case, no party has questioned whether the coal ash basin closure costs for which the Company seeks recovery are "known and measurable"; indeed, the Company documented these costs and has shown that they were in fact incurred. Rather, the arguments raised by Intervenors challenging the inclusion of the Company's coal ash basin closure costs in rates center on whether those costs are "reasonable and prudent" and whether they are "used and useful." These concepts have been framed by this Commission and the North Carolina Supreme Court.

A. Reasonable and Prudent

The seminal treatment of "reasonable and prudent" costs is this Commission's order entered in Docket No. E-2, Sub 537 (the 1988 DEP Rate Case), in which the Commission approved with some exceptions costs the Company incurred in connection with the construction of Unit 1 of the Shearon Harris nuclear plant. See 1988 DEP Rate Order. The Commission there articulated the following principles governing the question of "reasonable and prudent":

First, the standard for judging prudence is "whether management decisions were made in a reasonable manner and at an appropriate time on the basis of what was reasonably known or reasonably should have been known at that time. ... [T]his standard ... must be based on a contemporaneous view of the action or decision under question. Perfection is not required.

Hindsight analysis – the judging of events based on subsequent developments – is not permitted." 1988 DEP Rate Order, p. 14.

Second, challenging prudence requires a detailed and fact intensive analysis, and the challenger is required to (1) identify specific and discrete instances of imprudence; (2) demonstrate the existence of prudent alternatives; and (3) quantify the effects by calculating imprudently incurred costs. Specifically,

- A decision cannot be imprudent if it represents the only feasible way to accomplish a necessary goal.
- The Commission can only disallow imprudent expenditures – that is, actions (even if imprudent) with no economic impact upon customers are of no consequence. Thus, identification of an imprudent action or inaction is not by itself sufficient; rather, there must be a demonstration of the economic impact.
- The proper amount chargeable to customers is what the expenditure would have been absent the imprudent acts or decisions of management.

Id. at 15. The North Carolina Supreme Court upheld the Commission's prudence determination. See Thornburg II, 325 N.C. at 489, 385 S.E.2d at 466 (finding "no error" in that portion of the Commission's decision).

B. Used and Useful

"Used and useful" is a concept directly embedded in the ratemaking statute – N.C. Gen. Stat. § 62-133(b)(1) states that the Commission must "Ascertain the reasonable original cost of the public utility's property used and useful, or to be used and useful within a reasonable time after the test period, in providing the service rendered to the public within the State, less that portion of the cost which has been consumed by previous use recovered by depreciation expense ...." In general, the Supreme Court's treatment of the concept has been in the negative, i.e., asserting as a basis for its decision that something is not "used and useful" – for example, excess common facilities are not "used and useful" as a matter of law, see Thornburg II, 325 N.C. at 495-96, 385 S.E.2d at 469, and a water treatment plant that was not in service as of the end of the test year and would never again be in service was not "used and useful" within the meaning of N.C. Gen. Stat. § 62-133(b)(1). State ex rel. Utils. Comm'n v. Carolina Water Serv., Inc., 335 N.C. 493, 508, 439 S.E.2d 127, 135 (1994). The reverse, of course, is that if the expenditures do support and provide service to customers, the costs are "used and useful."

C. Burden of Proof

The Commission must address arguments on the burden of proof. DEC argues that it incurred the CCR remediation costs at issue, meeting its prima facie burden and that Intervenors have failed to justify discrete disallowances. The AGO argues DEC bore the burden of quantifying the disallowances the AGO deems appropriate. DEC argues that the substantive standard is imprudence. Others argue that the standard is one of due care. The CCR remediation costs DEC seeks to recover in this docket and that are being challenged by Intervenors consist of 2015-2017 costs to dewater, remove, and transport CCRs from unlined repositories and store them in lined ones or to install caps. DEC incurs these costs pursuant to requirements of EPA CCR Rule and North Carolina CAMA provisions or other requirements of DEQ. In compliance with this Commission's authorization, these costs have been accounted for in an Asset Retirement Obligation account and have been deferred to permit appropriate ratemaking treatment in this case.

The AGO argues that DEC should bear the burden to disprove why disallowances to its 2015-2017 CCR remediation costs should not be accepted.

> The AGO does not agree that the factors the Commission found appropriate for an approach taken by an independent auditor in the 1988 DEP Order should have been applied in the 2018 DEP Rate Order as a prudence framework, and similarly in this general rate case, the prudence framework is inappropriate because it essentially puts the burden of proof on intervenors, contrary to settled law. As the Commission observed in the 2018 DEP Order, because costs are site-specific, establishing a past cost would be a "near impossibility." 2018 DEP Order p. 200. As discussed in detail in Part I.B below, there is extensive affirmative evidence that Duke's imprudent management of coal ash disposal and coal ash sites, and its delays in addressing known problems, have driven up the costs now being incurred and have shifted the costs onto future customers unfairly. It is not appropriate to require ratepayers to prove that costs are unrecoverable; rather it is up to Duke to prove that some or all of the detailed costs are not attributable to the poor history of operations; that prudent alternatives that would have reduced the costs were not available when problems became known; and that these factors support the reasonableness of the costs Duke seeks to recover.

AGO's Brief, pp. 9-10.

The AGO cites no authority for this argument, nor does it argue that cases and precedent relied upon by DEC and the Commission in the 2018 DEP case to the contrary are wrongly decided or should be ignored. While asserting that the Commission's reliance on established evidentiary principles in the 2018 DEP case is "contrary to law," the AGO cites no authority to back up its assertion. The AGO asserts in response to DEC's petition to recover 2015-2017 CCR remediation costs -- costs no party asserts DEC did not incur -- that these costs should be disallowed due to DEC's imprudence in years prior to 2015. These are the AGO's allegations, not DEC's. The AGO's novel theory that a petitioner should bear the burden to disprove Intervenor allegations unsupported by evidence is one the Commission does not accept. The AGO's theory of its case, at least in its brief, appears to be that if DEC had acted to remediate CCR disposal and storage issues in years prior to 2015, DEC's costs would have been lower, so the 2015-2017 costs are excessive.

To prevail, the AGO must quantify what the costs of the actions not taken should have been. The AGO argues DEC failed to act appropriately before 2015. DEC cannot be expected to provide costs of acts not taken. The AGO has not undertaken this task.

While some of the costs to comply with the requirements of environmental regulators are challenged by Intervenors as excessive, i.e., unreasonable, most of the costs being challenged are questioned on the theory that DEC is in breach of a standard classified as a "duty to exercise due care." The challenge equates failure to meet a due care standard with management imprudence. According to this theory, even though no environmental regulatory requirement imposed a duty to remove CCRs from unlined impoundments before EPA CCR rules or CAMA, management was imprudent in not doing so. The challenge does not address DEC's decisions to initially place the CCRs in unlined impoundments between 1945 and 1982, but its failure to remove the CCRs thereafter or alternatively to cease to sluice CCRs to these unlined impoundments at a time when trends within the industry suggested that leachate finding its way into groundwater from the bottom of the unlined repositories posed potential risks to the environment and human health.

The Commission has not been cited any case to support the theory that, in determining the recovery through utility rates, costs of environmental remediation incurred by management to comply with express requirements of environmental regulators, management's decisions should be assessed against a standard of due care. The Commission's duty is not to determine liability to and assess damages for torts committed by management for injury to the environment or to receptors of contaminants. Environmental regulators and courts of general jurisdiction are the appropriate arbitrators of those disputes. DEC's unlined impoundments at issue operated pursuant to environmental permits as wastewater treatment facilities by DEQ or its predecessor. That agency's statutory mandate is environmental protection and would be the agency to rectify a breach of a duty of due care, if any, such as that advocated by certain Intervenors in this case. The issue before this economic regulatory tribunal is imprudence - who should bear the remediation costs - the utility's stockholders or its consumers and on the basis of what justification.

According to the U.S. Supreme Court:

> Good faith is to be presumed on the part of managers of a business. ... In the absence of showing of inefficiency or improvidence, a court will not substitute its judgment for theirs as to the measure of a prudent outlay.

West Ohio Gas Co. v. Ohio Pub. Utils. Comm'n., 294 U.S. 63, 72, 55 S. Ct. 316, 321 (1935).

In a case cited with favor in Priest, Principles of Public Utility Regulation:[1]

> Only where affirmative evidence is offered challenging the reasonableness of the operating expenses incurred, on the grounds that they are exorbitant, unnecessary, wasteful, extravagant, or incurred in the abuse of discretion or in bad faith, or are of a nonrecurring character not likely to recur in the future, has the commission a reasonable discretion to disallow any part of the expenses actually incurred.

[1] A.J.G. Priest, Principles of Public Utility Regulation 1969, Vol. I, pp. 422-23.

Alabama Pub. Serv. Comm'n v. Southern Bell Tel. & Tel. Co., 253 Ala. 1, 42 So.2d 655, 674 (1949) cited with approval, State ex rel. Utils. Comm'n. v. Intervenor Residents, 305 N.C. 62, 77, 286 S.E.2d 770, 779 (1982).

This standard against which costs recovery challenges are measured has elements qualitatively and quantitatively distinct and more rigorous than a tort standard of due care. The expert witnesses sponsored in this case failed to support allegations of discrete actions constituting imprudence. For its equitable sharing disallowance, the Public Staff proceeded on an equitable sharing theory, not on a theory of imprudence. AGO witness Wittliff on cross-examination failed to show what DEC should have done differently to remediate CCR, when it should have acted, and what the cost of such alternative conduct should have been. While AGO witness Wittliff filed forceful allegations on paper in the prehearing filings, much as was the case in the DEP rate hearing, his support of that testimony from the stand on cross examination was not persuasive.[1] Public Staff witness Junis likewise could not identify costs DEC would have incurred to remediate prior to 2015.[2] Without record evidence from parties advocating disallowances for failure to take CCR remediation steps prior to 2015 pursuant to the burden of proof theory or an unsupported "failure to exercise due care standard" of what action DEC should have taken, when it should have acted, and what the costs would have been, the Commission cannot approve such specific disallowances. Attempts to identify years-old hypothetical past costs, for example, by allocating

[1] Q. Beginning on line 16, you state, "However, when it came to making changes to its own unlined surface impoundments, the Company chose not to move forward with the industry, but instead chose to add more and more coal ash to the unlined impoundments despite the longstanding seepage and groundwater issues at its facilities."

Did I read that correctly?

A. You did.

Q. Mr. Wittliff, despite your 30 years of experience as an engineer, I am correct, am I not, that if I look through the entirety of your testimony in this case and all of your exhibits, I will not find any engineering analysis of what exactly that DEC should have done, when it should have done it, where it should have done it, and how much it would have cost with respect to the lines in the testimony that I just read you, will I?

A. Say that again, please.

Q. Yes, sir. You make a contention, on page 10 of your testimony, on line 17 through 20 that I just read, alleging that DEC chose not to move forward with the industry, but instead chose to move more and more coal ash to unlined impoundments.

My question is, if I want to look at how I should have moved forward with the industry, where I should have done it, when I should have done it, how much it should have cost me - and by "me," I'm referring to DEC - I cannot find those answers anywhere in your prefiled testimony, can I?

A. No.

Tr. Vol. 11, pp. 283-84

[2] "The coal ash-related environmental violations have a cost. Corrective actions to address environmental impacts under CAMA and the Environmental Protection Agency's (EPA) Coal Combustion Residuals Final Rule (CCR Rule), including ultimately closure of all DEC ash basins, will remedy the environmental violations. Therefore, it is not feasible to identify all the costs that would have been incurred to remedy violations under the pre-existing environmental regulations and laws, such as 15A NCAC 02L (2L rules) and North Carolina General Statute 143-215.1, if CAMA and the CCR Rule were not in effect. . . . There is no doubt that substantial assessment and remedial costs would have been incurred without CAMA and the CCR Rule, but, in my opinion, those costs cannot be quantified without undue speculation."
Tr. Vol. 26, pp. 646-47

tons of CCRs to formulate inexact allocation percentages to be applied to 2015-2017 costs is to rely upon guesswork that simply is legally and equitably deficient.[1]

Coal ash located within basins above levels saturated by water and unaffected by the contours of the bottom of the impoundment can be removed at a cost lower than coal at lower levels. Costs of replacement repositories will vary depending on land costs, location, regulatory requirements and site preparation costs. Transportation costs will vary depending on distance, market conditions, regulatory requirements and timing of incurrence.

Efforts to identify what DEC should have done prior to EPA CCR and CAMA, when it should have done so and what the costs should have been even with the benefit of 20/20 hindsight pose insurmountable obstacles. CCR remediation even under the supervision of NC DEQ is a site-specific undertaking with procedures that have evolved over time and continue to do so. Without statutory or regulatory standards and guidelines to follow, no one can say what the prudent course would have been even if one acts on the assumption that DEC was imprudent to await promulgation of the definitive environmental regulatory requirements.

Under EPA CCR regulations and CAMA requirements, the prevalent remediation remedy is dewatering, excavation and removal or cap-in-place. These explicit, express requirements depend heavily on NC DEQ oversight and supervision. The remediation steps must be completed in compliance with deadlines and substantial collaboration between NC DEQ and DEC with respect to permitting. Compliance will occur as far into the future as 2028. No one can predict today how compliance will be accomplished or what these future compliance costs will be. The decision by NC DEQ on whether cap-in-place for eligible impoundments versus CCR removal has yet to be made. Yet Intervenors ask the Commission to look backward where the regulatory requirements were not in place and therefore unknown and speculate what it would have cost to comply so as to impose the imprudence disallowance. Having failed to even attempt to quantify such a disallowance, Intervenors' theory is without probative support and must be rejected.

Without any requirement such as EPA CCR rules or CAMA to remediate CCRs stored in unlined pits simply because unlined pits posed "potential" threats to the environment, Intervenors must "pick a date" when in their opinion such remediation should have been undertaken. Likewise, Intervenors apparently assume the remediation remedy would have been dewatering, excavation and removal or perhaps cap-in-place, even though they do not agree on which of these alternatives is appropriate for each basin. No support for this assumption exists. Without requirements such as those of EPA CCRs and CAMA, DEC logically would have attempted to investigate each unlined repository to determine insofar as possible the extent to which contamination was occurring or had the potential to occur. Absent evidence of actual or probable future contamination, DEC would have been remiss in spending millions of dollars to remediate or to choose the most expensive remediation alternative.

As to impoundments where contamination was occurring or potentially would occur, remedies far short of complete excavation such as installing water extraction methods beyond the

[1] When quantifying quantities of CCR for purposes of cap-in-place, utilities rely upon linear measurements, not tonnage.

impoundment to remove water or to excavate contaminated soil were available and arguably should have been employed as a least cost solution.

Any CCR impoundment leaks, whether lined or unlined. The underlying soil composition and subsurface groundwater flow direction for each site are significant considerations in assessing risk of harmful contamination from CCR constituents. Piedmont red clay acts as a natural sealant. Unless CCR contaminants in excess of proscribed levels migrate beyond boundaries outside repositories, no actionable threat occurs. Monitoring wells provide tools to measure migration of harmful constituents. Determinations of naturally occurring levels of CCR contaminants must be made to determine whether measurements in excess of published standards, if any, originate at the impoundment.

Determining the number and placement of monitoring wells, not an inexpensive endeavor (Tr. Vol. 26, p. 92), is an inexact science. The prevalent and cost-effective process is to install monitoring wells iteratively to best identify harmful groundwater contamination. Tr. Vol. 26, pp. 92-93. Evidence of excessive constituent levels up gradient of impoundments tells nothing about impoundment contamination but is necessary to identify naturally occurring constituents that may or may not exist down gradient. Unlike synthetic contaminants like dry cleaning fluid or nuclear waste where evidence of its presence in groundwater can be tied to a source of pollution, all the potentially harmful elements from coal ash occur naturally in the ambient environment. Tr. Vol. 26, pp. 92-93. Underground water flows may dissipate excessive levels of CCR contaminants through natural attenuation to those below standard thresholds. There may be no receptors in the vicinity of the impoundment.

The best evidence of the difficulty in determining what DEC should have done, when it should have done so and what the cost should have been prior to 2015 is the significant dispute that arises in this case over what DEC should have done, when it should have done so and what the costs should be with respect to the actual 2015-2017 costs. DEC actually has incurred these costs in its efforts to comply with EPA CCR and CAMA published standards and requirements undertaken under NC DEQ's supervision and guidance. Parties to this case hotly dispute where replacement repositories should be constructed, when and how CCRs should have been transported, and which CCRs should have been designated for beneficial reuse.

Consequently, the Commission determines that efforts to recreate the past as no party has been able to do so is a fruitless endeavor that the Commission is unable and unwilling to undertake.

Additional complications to certain Intervenors' theory that disallowances to 2015-2017 CCR remediation costs should be made because DEC failed to begin remediation or alternative CCR storage earlier magnify the fatal flaw in the theory. From an accounting cost recovery perspective, the Commission authorizes establishment of an ARO, defers costs for remediation, and later amortizes these deferred costs over five years. DEC began to incur the remediation costs in 2015 and will continue to do so under EPA CCR and CAMA regimes until 2028. Consequently, under procedures being followed, cost recovery will occur through 2033. If, under certain Intervenors' theory, DEC should have begun remediation in 2006 (hypothetically, because Intervenors cannot identify the starting date under their theory), DEC would still have been incurring CCR remediation costs during the test year and would have been amortizing CCR remediation costs from prior years. Consequently, ratepayers paying rates established in this case could very well face the possibility of being no better off under Intervenors' alternative, unsubstantiated theory. Perhaps, arguably, DEC should have established a coal ash remediation cost ARO earlier in anticipation of a future requirement to undertake remediation efforts, and costs not so accounted for should be disallowed. However, the Commission's practice is not only to approve the establishment of the ARO but to defer the costs accounted for in the ARO for later recovery in a general rate case. Theories relied upon to recreate the past based on hypothetical scenarios all depend on guesswork and subjective factual constructs that are beyond the ratemaking standards this Commission must employ.

The burden of proof to show that rates are just and reasonable is always on the utility. See N.C. Gen. Stat. § 62-134(c). Intervenors, however, have a burden of production in the event that they dispute an aspect of the utility's prima facie case. See, e.g., State ex rel. Utils. Comm'n v. Conservation Council, 312 N.C. 59, 64, 320 S.E.2d 679, 683 (1984) (utility's costs are "presumed to be reasonable" unless challenged); State ex rel. Utils. Comm'n v. Intervenor Residents of Bent Creek/Mt. Carmel Subdivisions, 305 N.C. 62, 76-77, 286 S.E.2d 770, 779 (1982) ("The burden of going forward with evidence of reasonableness and justness arises only when the Commission requires it or affirmative evidence is offered by a party to the proceeding that challenges the reasonableness of expenses...."). If the Intervenor meets its burden of production, the ultimate burden of persuasion reverts to the utility, in accordance with N.C. Gen. Stat. § 62-134(c).

The Commission has consistently followed this shifting burden framework. See, e.g., DEC Remand Order, (Docket No. E-2, Sub 1142) p. 34. In practice this means that Intervenors may not rest merely on arguments and theories, they must adduce actual evidence challenging some aspect of the Company's cost recovery case. Further, that evidence must support the Intervenor's challenge under the substantive standard established by North Carolina law. Evidence predicated on 20/20 hindsight is insufficient to effectuate a prudence challenge, inasmuch as the substantive prudence standard forbids hindsight analysis.

D. Conclusion with respect to January 1, 2015 - December 31, 2017 Costs

The Commission determines that the Company has met its burden – both the prima facie burden of production and the ultimate burden of persuasion – of showing that the coal ash basin closure costs it actually incurred from January 1, 2015 through December 31, 2017 are recoverable and that a return, but one reduced to recognize a mismanagement penalty, is warranted, and that the Commission with contrasting evidence on the merits, with exception addressed below, authorizes recovery.

First, Company witness Kerin demonstrated that the Company's coal ash management historical practices (i.e., pre-CCR Rule and pre-CAMA) have generally comported with industry practices and then-applicable regulations, especially in this region of the country. See, e.g., Tr. Vol. 14, pp. 99-100, 135. The Commission determines that compliance with industry standards is an important but not the sole criterion in determining the recoverability of CCR remediation costs. As part of his work to bring DEC into compliance with the new CCR Rule and CAMA, witness Kerin helped establish and participated in an industry peer group consisting of representatives of, for example, Dominion and Southern Company, and his interaction with that group and his investigation of practices at other Duke Energy Corporation-affiliated utilities confirm his conclusion that the Company's practice was not out of line with the overall industry practice. Id. at 96-97. As witness Kerin testified, when he looked at all of the practices at the Duke Energy Corporation utilities, in multiple states, "Indiana, Ohio, North Carolina, South Carolina, and Florida, all those practices were the same, so that led me to believe that all those [companies], prior to becoming Duke Energy companies, were managing their ash and their ash basins in the same manner." Id. at 158-59. He made the same observation concerning the peer group of companies – AEP, Dominion, the Southern Companies and TVA – and "their practices were similar." Id. at 159. He concluded: "So that whole group of states across the eastern part of the United States, we were operating our basins in the same fashion." Id.

Witness Kerin's testimony on this point was not seriously or credibly controverted by any Intervenor. Indeed, AGO witness Wittliff was not able to specify exactly how the Company should have acted differently in managing its coal ash to be consistent with industry, at which sites it should have taken those actions, and how much those actions would have cost the Company. Tr. Vol. 11, pp. 283-89. Witness Wittliff also presented no credible evidence showing DEC's engineering and design of its impoundments was not consistent with industry practice and regulatory requirements at the time other than his own, subjective allegations. Tr. Vol. 24, p. 121.

Moreover, key documents that Intervenors used in cross-examination in an effort to rebut witness Kerin's testimony contain provisions that in part support, to some extent at least, his testimony and these findings. For example:

- Los Alamos Laboratory Report (1979): "Much of the ash produced by coal ash combustion is discharged into ash ponds." Sierra Club – Kerin Cross Ex. 3, p. 6.
- EPRI Coal Ash Disposal Manual (1981): No coal ash was landfilled in either North or South Carolina; rather, all of it was stored in ponds. Sierra Club – Kerin Cross Ex. 4, Table 3-1, pp. 3-7. Further, 81% of the coal ash produced in the Southeast was placed in ponds. Id. at 3-8.
- EPA Report to Congress (1988): This Report (Sierra Club – Kerin Cross Ex. 5) confirms that the Company's disposal of coal ash in ponds conformed in large measure to industry practice. The Report refers to ponds as "surface impoundments" Id. at 4-11, and notes that CCR waste management practices varied by region, and that in the South (EPA Region 4, which includes North and South Carolina) 95% of the plants manage their CCRs on-site. Id. at 4-23. The Report continues, "On-site management is common because utilities in this region often use surface impoundments, which are typically located at the power plant." Id. It noted further that "access to abundant, inexpensive supplies of water ... [in Region 4] often made it economical to use this management option." Id. at 4-20.

The 1988 EPA Report also indicates that "until recently, most surface impoundments and landfills used for utility waste management have been simple unlined systems," and that "liner use has been increasing in recent years." Id. at 4-33. Intervenors point to these statements to argue that the Company's continued use of unlined ponds was outside standard industry practice and is otherwise imprudent. The Commission disagrees. The Report notes, for example, that 87% of surface impoundments were unlined (id. at 4-33), and that neither North Carolina nor South Carolina required liners. Id. at 4-3. It also notes that one-fifth of waste generated by coal-fired power plants was reused, and "the remaining four-fifths are typically disposed in surface impoundments or landfills." Id. at ES-2. The Report thus validates witness Kerin's testimony that "unlined basins were the industry standard" at that time. Tr. Vol. 24, pp. 128-29. As he stated, "the EPA report focused on new landfills and surface impoundments, while DEC last constructed a new ash basin in 1982." Id. at 129 (emphasis in original). This was six years before the EPA Report was submitted to Congress. As witness Kerin stated further, in the DEP case AGO witness Wittliff testified that the majority of utilities continued to use unlined wet ash impoundments even after this timeframe, "because '[t]he law allowed them to do it, and the law continued to allow them to do it.'" Id. at 122. Finally, witness Kerin's conclusion is supported by the preamble to the CCR Rule itself. See Public Staff Kerin Cross-Examination Ex. 4.

Based upon similar evidence in the DEP case, the Commission found that "[s]ince the 1950s, standard industry practice at least in the Southeast, has been to deposit in coal ash basins, and such basins were constructed and used at all of the Company's coal-fired generating units." 2018 DEP Rate Order, p. 142. This finding and witness Kerin's testimony are also consistent with the Commission's findings in the 2016 DNCP Rate Order: "DNCP, like many electric utilities in the United States, has for decades generated electricity by burning coal. During those decades, the widely accepted reasonable and prudent method for handling CCRs has been to place them in coal ash landfills or ponds (repositories)." 2016 DNCP Rate Order, p. 60.

It is undisputed that there will be a natural flow from an unlined basin into groundwater. This is a function of basic science. Tr. Vol. 13, p. 58. As Company witness Wells testified:

> Earthen basins and dike walls are prone to the movement of liquid through porous features within those structures through a process known as seepage. Such seepage is common, and, to a degree, is necessary to maintain the stability of an earthen dam or dike wall; otherwise they become saturated, which may reduce margins of safety with respect to their structural integrity.

Tr. Vol. 24, p. 246. Accordingly, seepage from the Company's unlined ash basins – basins that complied with industry standards and the then-applicable regulatory requirements – is part of the "normal operation" of the basins. This evidence of the Company's historical compliance establishes that, except in limited fashion, its past coal ash management practices did not cause it to incur in the January 1, 2015 – December 31, 2017 timeframe unjustified costs to comply with current laws and regulations. Tr. Vol. 14, pp. 100-01.

Second, witness Kerin's testimony established that in large measure the costs were reasonable and prudent. In light of the evidentiary presumptions and shifting burden of production and persuasion, and based on the Commission's assessment of the credibility of the witnesses opining on the facts and policy considerations at issue, the Commission relies heavily on his testimony. The testimony of other Company witnesses, including witness Wells, will be discussed in greater detail in the sections of this order dealing with the Public Staff's specific disallowance recommendations. Witness Kerin's testimony was credible, demonstrated command of the subject matter (he testified, after all, that he had "lived" with that "company-specific subject matter every day for the past four years" (Tr. Vol. 24, p. 92), and the Commission determined in the 2018 DEP Rate Order that he has "'lived' this project since its inception," (2018 DEP Rate Order, p. 187), and the Commission concludes that his conclusions were not dislodged after being subjected to vigorous cross-examination.

Third, witness Kerin's testimony establishes that the capitalized costs for which the Company seeks recovery are eligible for a return and, at least to the extent they are capital in nature, were used and useful. These costs were expended to comply with the CCR Rule and CAMA, along with consent agreements that require the Company to implement corrective actions consistent with either or both of those regulatory requirements. Tr. Vol. 14, p. 115. Capital expenditures undertaken to enable compliance with the law qualify as "used and useful," in that the Company does not have the option to fail to comply, and, as indicated in the testimony of Company witness Wright, are routinely recoverable in rates. Tr. Vol. 14, p. 115; Tr. Vol. 12, p. 131. Further, witness Kerin's testimony (see Tr. Vol. 14, p. 135 and Kerin Ex. 10 and Ex. 11) details the "core components" of the costs incurred. These include, for example:

- With respect to the Allen and Belews Creek Plants' coal ash basins, oversight and environmental health and safety (EHS) activities, engineering and basin closure projects;
- With respect to the Buck Plant's coal ash basins, EHS activities, basin closure costs, mobilization and beneficiation costs;
- With respect to the Cliffside Plant's coal ash basins, mobilization and infrastructure costs, water management, ash processing, basin support projects, inspections and maintenance, and EHS activities;
- With respect to the Dan River Plant's coal ash basins, mobilization and infrastructure costs, water management, ash processing, landfill construction, engineering closure costs, and EHS activities;
- With respect to the Marshall Plant's coal ash basins, EHS activities, inspections and maintenance;
- With respect to the Riverbend Plant's coal ash basins, ash processing, water management, and EHS activities; and
- With respect to the W.S. Lee Plant's coal ash basins, mobilization, ash processing, and engineering closure plans.

Witness Kerin testified further that mandated closure of the existing coal ash basins meant that the modifications had to be made to their associated power plants, so as to direct storm water flow away from the ash basins and to cease bottom ash and fly ash sluice flow to the basins. Tr. Vol. 14, p. 133. In addition, other process streams must be directed away from the coal ash basins to facilitate de-watering and closure. Id.

Witness Kerin and his supporting exhibits describe costs expended to facilitate the Company's handling and storage of coal ash, so as to conform to the new legal requirements imposed on the Company resulting from the promulgation of the CCR Rule and the passage of CAMA. DEC is subject to these new legal requirements and must handle and store coal ash in a manner that complies with them. As such, except as detailed below, the capital costs of compliance are "used and useful," and the Company is authorized to recover them along with other costs accounted for in the ARO, along with a return as adjusted below on its outlay of these funds.

1. Intervenor Challenges to Cost Recovery

Intervenors have mounted challenges to the Company's recovery (with a return) of its already-incurred coal ash basin closure costs on two levels. First, in a manner that departs from the prudence framework the Commission established in the 1988 DEP Rate Case, the AGO, through witness Wittliff; CUCA, through witness O'Donnell; and the Public Staff, through witness Maness, all advocate that costs be disallowed even without a detailed analysis of the specific costs the Company has submitted for recovery.[1] Second, the Public Staff (and only the Public Staff) proposes to disallow specific costs incurred through the testimony of witnesses Garrett and Moore, and Junis, thus at least attempting to follow the Commission's prudence framework.

However, the Commission determines that these approaches are not appropriate, and these proposed specific disallowances are not approved.

2. AGO/CUCA Approach: The Company "Caused" CAMA

At the hearing, in response to questions by counsel for the Company, witness Wittliff admitted that, while his testimony stated that he would support a Commission finding that the coal ash costs incurred by DEC were unreasonable and imprudent, his actual position is that the Company should be able to recover its costs to comply with the CCR Rule, but nothing more. Tr. Vol. 11, pp. 279-81. He stated that costs incurred by the Company to comply with the CCR Rule are reasonable and prudent. Id. at 282-83. In contradiction to its witness, the AGO in its brief asserted that all the CCR cost recovery DEC seeks in this case is imprudent. Not only has the AGO been unable to quantify the costs DEC should have incurred prior to 2015, it has failed to sponsor a witness that can support its theory of the case. While purporting to represent consumers, the AGO's theories and recommended disallowances are inconsistent with those of the Public Staff, tasked with representing the same constituency.

Witness Wittliff admitted that he did not identify any specific costs that could have been lower or should be disallowed. Id. at pp. 287-89. However, witness Wittliff continued to pose the theory that the Company "caused" CAMA, and while he cannot point to imprudent action on the part of DEC in undertaking to comply with CAMA, the fact that the Company "caused" the statute to be enacted affects its ability to recover its CAMA-related costs. Tr. Vol. 11, pp. 239, 248-50, 272. CUCA witness O'Donnell agrees. Tr. Vol. 18, pp. 59-60 (Company caused CAMA and therefore should not recover any CAMA cost).

In these witnesses' view, CAMA sets a more aggressive coal ash basin closure schedule for certain of the Company's basins than would have been set under the CCR Rule alone, and the

[1] Sierra Club witness Quarles asserted that continued storage of coal ash at Allen and Marshall poses significant environmental risks, and concluded that closure in place at these basins would allow continued contamination of downgradient groundwater and violate the technical standards of the CCR Rule, and that removal of coal ash from DEC's ash basins would reduce the concentrations and extent of this contamination. Tr. Vol. 6, pp. 17-118; 119-27. Witness Quarles made no effort to quantify the economic impact of his recommendation, which would increase cost to customers. The Commission is persuaded by the evidence presented by witness Kerin and witness Moore that the closure plans for the Allen and Marshall Plants are appropriate. DEQ will be responsible for determining which closure plans are appropriate for Allen and Marshall. The Commission determines that the associated expense for Allen and Marshall is reasonable and prudent.

more aggressive schedule leads, again in their view, to higher costs. Witness Wittliff testified that he "[didn't] know quantitatively, because [he] didn't do that kind of analysis," in regard to what costs the Company would have eventually been required to undertake by the CCR Rule and CAMA, despite any exceedances, violations, criminal prosecutions, and civil and administrative lawsuits. Tr. Vol. 11, pp. 282-83.[1] Accordingly, the Commission determines that witness Wittliff's opinion cannot legitimately support disallowances, because it fails with respect to the prudence review framework the Commission established in the 1988 DEP Rate Case: (1) it fails to identify specific and discrete instances of imprudence; (2) it fails to demonstrate the existence of prudent alternatives; and (3) most importantly, it fails to quantify the effects by calculating imprudently incurred costs.

Witness O'Donnell proposes a 75% disallowance, but he does so predicated not on a calculation of "imprudently incurred costs" as required by the Commission's framework, but rather based on what he terms a "financial analysis" through comparison of the size of the ARO established by the Company to capture coal ash basin closure expense associated with CCR Rule and CAMA compliance with the AROs established by other utilities to capture their coal ash basin closure expense. This "calculation" is unpersuasive, however, as demonstrated by witness Kerin, (see Tr. Vol. 24, pp. 124-28), and as the Commission determined in the DEP case. See 2018 DEP Rate Order, p. 196. In particular, the analysis lacks any attempt by witness O'Donnell to account for the differences in which different utilities may have valued their closure cost estimates, or the differences in the timing of their estimates. As the Commission held in the 1988 DEP Rate Order, industry comparisons, even if relevant, are "of little value in determining specific acts of imprudence." 1988 DEP Rate Order, p. 56. The Commission agreed with the Company's witness that "[t]he flaw in industry comparisons ... is that there are unique conditions on every nuclear project so that no projects are exactly comparable" (id.), and the same applies to AROs established by different utilities to capture their specific coal ash basin closure costs. Witness Kerin indicates, and the Commission agrees, that this renders witness O'Donnell's "analysis" without significant probative value – it is not a true apples-to-apples comparison of the utilities' AROs.

A more fundamental reason demonstrates why the Commission determines it should not accept the opinions of witnesses Wittliff and O'Donnell – the notion that the Company was the direct cause of CAMA is of limited legal basis. Witness O'Donnell presents no evidence of such direct causation, and witness Wittliff appears to base his opinion on a draft preamble to the Senate bill (Tr. Vol. 11, pp. 240, 248-50), notwithstanding the fact that this preamble is not present in the final ratified bill.[2] Moreover, in North Carolina, legislative intent is ascertained by the plain words of the statute. Rhyne v. K-Mart Corp., 149 N.C. App. 672, 562 S.E.2d 82 (2002). "Legislative history" of the type seemingly relied upon by witness Wittliff is legally impermissive. In State v. Evans, 145 N.C. App. 324, 550 S.E.2d 853 (2001), the Court stated:

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[1] The AGO complains that the Commission imposes an inappropriate burden upon it to offer evidence to quantify the disallowances it advocates. The AGO cannot legitimately assert that the burden is unfair when it has failed to undertake the task of attempting to elicit that evidence. The AGO has undertaken substantial discovery of DEC in this case. Based on the omissions in its presentation, the AGO apparently failed to "close the loop" in seeking to elicit evidence on what it would have cost to take the remediation steps it alleges DEC should have taken prior to 2015.

[2] See N.C. Gen. Stat. § 130A-309.200, et seq.

> While the cardinal principle of statutory construction is that the words of the statute must be given the meaning which will carry out the intent of the Legislature .... [t]estimony, even by members of the Legislature which adopted the statute, as to its purpose and the construction intended to be given by the Legislature to its terms, is not competent evidence upon which the court can make its determination as to the meaning of the statutory provision.
>
> Thus, "[e]ven the commentaries printed with the North Carolina General Statutes, which were not enacted into law by the General Assembly, are not treated as binding authority by this Court." Accordingly, press releases and commission recommendations offered by defendant as evidence of the punitive purpose behind [the statute] are in no manner binding authority on this Court.

145 N.C. App. at 329-30, 550 S.E.2d at 857 (citations omitted). Accord. Elec. Supply Co. of Durham v. Swain Elec. Co., 328 N.C. 651, 657, 403 S.E.2d 291, 295 (1991); Styres v. Phillips, 277 N.C. 460, 472, 178 S.E.2d 583, 590 (1971) ("The intention of the legislature cannot be shown by the testimony of a member; it must be drawn from the construction of its acts.").[1]

Even if the actions or inactions of DEC or one of its sister companies was a direct cause of CAMA as these witnesses allege, such direct causation alone is not sufficient legal basis for disallowing otherwise recoverable costs. If the North Carolina General Assembly had intended to give the Commission the authority to deny otherwise recoverable environmental compliance costs due to some punitive theory of causation, it could have said so – and it did not. The legislature does not operate in a vacuum. Rather, it operates within the context of N.C. Gen. Stat. § 62-133, in which prudently incurred costs are recoverable. Had it intended to disavow the routine cost recovery standard, it can be expected that the legislature would have had to do so explicitly. Accordingly, witnesses Wittliff and O'Donnell theories of punitive causation do not comport with the controlling law of this state.

3. The Public Staff's "Equitable Sharing" Concept

In this case, as in the 2018 DEP Rate Case, the Public Staff advocates an "equitable sharing" of coal ash basin closure costs. The Public Staff's equitable sharing proposal is supported by witness Maness. Tr. Vol. 22, pp. 70-85. Witness Maness achieves the sharing in the same manner in which he implemented the Public Staff's 50-50 sharing proposal in the 2018 DEP Case. First, he removes the unamortized coal ash basin closure costs from rate base, thereby, through that step, eliminating any return on that unamortized balance. Id. at 72. The second step is to choose an amortization period that will result in the desired level of "sharing." Id. The sharing level that the Public Staff and witness Maness deem "equitable" is 51% to the Company and 49% to

[1] In Styres v. Phillips, the Supreme Court also stated that "the rule is that ordinarily the intent of the legislature is indicated by its actions, and not by its failure to act." Styres, 277 N.C. at 472, 178 S.E.2d at 590. Accordingly, the suggestion through cross-examination questions by the AGO (see, e.g., Tr. Vol. 13, p. 22) that as CAMA does not contain an express provision mandating cost recovery of compliance costs, the General Assembly did not intend for the statute to allow such costs, is also without any basis. To the extent that any such evidence is competent, the most relevant evidence regarding the General Assembly's failure to act is the fact that on two separate occasions the General Assembly was presented with the opportunity to mandate non-recoverability of compliance costs, and on both occasions the provision so stating did not pass.

customers. Id. at 84. Mathematically that results in a 27-year amortization period (id.), although, when adjusted for the rate of return to which the Company and the Public Staff agreed, subject to the Commission's approval, was appropriate in this case, the amortization period is reduced to 25 years. Id. at 153. Even under the 25-year amortization period, however, the sharing level remains 51% to the Company and 49% to customers. Id. at 162.

The Commission chose not to accept the "equitable sharing" concept in the 2018 DEP Case, and does so again, on the same basis.

First, the concept is standard-less, and, therefore, from the Commission's view arbitrary for purposes of disallowing identifiable costs – there is no rationale that supports a substantially large 51% disallowance. The Public Staff chose a desirable equitable sharing ratio, then backed into the mechanism to achieve that level of disallowance, leaving the allocation subject to an arbitrary and capricious attack, particularly as it provides no explanation as to why the "equitable" split for DEP in the 2018 DEP Case was in its view 50-50, while the "equitable" split in this case is 51-49. As the Commission held in the 2018 DEP Case, the "Public Staff provides insufficient justification for the 50/50 [split] as opposed to 60/40 or 80/20 ...." 2018 DEP Rate Order, p. 189.

Black's Law Dictionary defines an "arbitrary and capricious" decision as one which, inter alia, is "without determining principle." See Tate Terrace Realty Investors, Inc. v. Currituck Cty., 127 N.C. App. 212, 222-23, 488 S.E.2d 845, 851 (1997). The Commission can discern no "determining principle" in the Public Staff's "equitable sharing" proposal. As such, were the Commission to adopt it, the Commission's action would be subject to an arbitrary and capricious attack and likely subject itself to reversal. An illustrative case is Sanchez v. Town of Beaufort, 211 N.C. App. 574, 710 S.E.2d 350 disc. review denied, 365 N.C. 349, 718 S.E.2d 152 (2011), in which the Court held that it was arbitrary and capricious for a municipal body to "cherry pick" a standard without providing any basis of any particular determining principle. Sanchez, 211 N.C. App. at 580, 710 S.E.2d at 354. In this case, the Beaufort Historic Preservation Commission (BHPC) attempted to limit the construction of petitioner's home to 24 feet in height "without the use of any determining principle from the BHPC guidelines." Id. at 582, 710 S.E.2d at 355. Rather, the BHPC members based the standard "on their own personal preferences," with each member providing a manner of re-working the project's construction to comply with a 24-foot height maximum, but none providing a reason as to why 24 feet when the height "could be a different number ...." Id. at 581 (emphasis in original). Thus, while the BHPC members could provide a way to arrive at the height maximum, they could not provide a "why" for that particular height maximum. Failure to provide a determining principle for the height maximum itself rendered the BHPC's decision arbitrary and capricious. Id. at 582.

Ultimately, the Public Staff, through witness Maness, indicates that "what is and what is not allowed in rate base is within the legal discretion of the Commission to decide." Tr. Vol. 22, p. 73. The Public Staff overstates the Commission's discretion, and to the extent the Commission possesses such discretion, the Commission chooses not to exercise it in the manner the Public Staff advocates. To understand exactly how, it is necessary first to examine the Public Staff's purported rationales for its sharing proposal. There are two: first, the Company's alleged past failures, as detailed in the testimony of Public Staff witness Junis, to prevent environmental contamination from its coal ash basins, and, second, an asserted "history of approval of sharing of extremely large costs that do not result in any new generation of electricity for customers." Id. at 71-72.

As to the first asserted predicate, the Company disputes such "failures," as set out in the testimony of Company witness Kerin. The Commission credits Kerin's testimony, as detailed below, but whether or not the Company were guilty of some sort of violation is insufficient to justify the Public Staff's 51/49 sharing proposal. Witness Maness admitted that these alleged acts or failures to act are related to past operations. Tr. Vol. 22, p. 80. No persuasive evidence exists that any of these actions or inactions caused discrete expenditures by the Company to comply with its CCR Rule and CAMA obligations, which are the costs that the Company seeks to recover. Past actions, even if imprudent in this context must result in quantifiable costs, which the Public Staff has not shown. Therefore, identification of an imprudent action or inaction is not by itself sufficient; rather, there must be a demonstration of the economic impact. 1988 DEP Rate Order, p. 15. The Public Staff has made no such demonstration in this case, and no such demonstration with respect to the Public Staff's 51/49 sharing arrangement.

Apart from his specific recommendation regarding disallowance of groundwater remediation expense (discussed below), witness Junis' testimony does not link the past actions of the Company to the costs it seeks to recover. As Company witness Wright indicates, to link alleged past "violations" to current compliance costs in the factual context of this case is to "put the Company in an untenable situation." Tr. Vol. 13, p. 39.

Past violations may well be imprudent, but with respect to the "question of responding to new regulations and new standards, that is a totally separate question." Id. The Commission agrees with this distinction. In keeping with its decision in the 1988 DEP Rate Order, this aspect of which was affirmed by the North Carolina Supreme Court, to permit disallowance there must an actual expenditure shown to be imprudently incurred.

The Public Staff's position, simply stated, is that it does not matter if the Company's actions in incurring the CCR Rule and CAMA compliance costs were prudent – the Public Staff's equitable sharing proposal would still apply. As witness Maness testified, "[E]ven if 'prudent'" (Tr. Vol. 22, p. 126), the Public Staff would still find it "appropriate to have the shareholders of those companies bear a greater share of the cleanup costs under an equitable sharing approach." Id. Accordingly, the predominant rationale for the Public Staff's proposal is witness Maness' second predicate: the proposition that the Commission has a "history of approval of sharing of extremely large costs that do not result in any new generation of electricity for customers." Id. at 72.

Witness Maness overstates his position – as witness Wright notes, there is "no provision of Chapter 62 requiring different treatment for 'extremely large costs'" (Tr. Vol. 12, pp. 156-21-156-22), and, witness Wright detailed any number of "extremely large cost" items not associated with new generation for which cost recovery is routinely allowed. Id. The Commission determines that this is another example of the arbitrariness inherent in the Public Staff's sharing proposal.

It appears that witness Maness' rationale for the sharing proposal is grounded in the Public Staff's view of the discretion available to the Commission. He states first that pursuant to N.C. Gen. Stat. § 62-133(b)(1), and with the exception of construction work in progress under certain circumstances, "the only costs that the Commission is required to include in rate base are ... the 'reasonable original cost of the public utility's property used and useful, or to be used and useful within a reasonable time after the test period ....'" Tr. Vol. 22, p. 73. He indicates that he is advised by counsel that "beyond these requirements what is and what is not in rate base is fully within the Commission's discretion to decide, as long as the rates set thereby are fair and reasonable to both the utility and the consumers." Id.

DEC and the Public Staff stridently debate whether the 2015-2017 CCR remediation costs if found used and useful and otherwise meet the test for amortization with a return on the unamortized balance "must" or "may" be approved. The Public Staff argues that approval of a return is discretionary. The Commission determines it unnecessary to determine whether the costs must receive a return on the unamortized balance. In its discretion, as expressly authorized by N.C. Gen. Stat. § 62-133(d), with the exception addressed below, it approves a return.

DEC argues that deferred 2015-2017 CCR remediation costs accounted for in an ARO as authorized by the Commission in its 2018 order should be amortized over five years and should earn a return on the unamortized balance. The Public Staff argues that these ARO costs should be amortized over 25 years with no return based primarily on an equitable sharing theory. In support of these parties' contrasting positions and in order to challenge the merits of their opposition, the parties laboriously debate issues of used and useful, "entitled" versus "eligible" for earning a return, plant in service versus working capital, capital costs versus expenses, etc. The parties arduously debate the applicability to this issue of cases addressing an abandoned sewage treatment plant, costs of discontinued nuclear projects, and manufactured natural gas remediation costs.

No witness argues that the Commission lacks the discretion to follow the precedent it established in the two previous cases, DNCP and DEP, where it addressed the issue of amortizing deferred ARO CCR remediation costs over five years and a return on the unamortized balance. No witness argues that the law forbids the Commission to authorize a return on the unamortized balance. The Commission chooses to exercise its discretion and authority under N.C. Gen. Stat. § 62-133(d) and follow its precedent here - amortize the ARO costs over five years and authorize a return on the unamortized balance. The Commission will address the lengthy arguments and debate, but determines that by and large the arguments are not particularly germane or dispositive to the Commission's decisions. The Commission will not accept the Public Staff equitable sharing argument primarily because the Commission determines in its discretion that amortization of the deferred ARO costs over 25 years is inequitable and finds inadequate support for a 50-50 or 51-49 sharing versus some other ratio. The justification for disallowance of 50% of the ARO costs is not persuasive. The Commission concludes that the Public Staff relies on the equitable sharing principle because it, like other Intervenors, has been unable to quantify a disallowance on the basis of the alleged DEC acts and omissions prior to 2015 providing the predicate for the requested disallowance. Instead, the Commission relies upon some of the evidence offered to support the equitable sharing theory to impose a management penalty as discussed below.

While arguments by the parties through analogy to cases on other issues provide some helpful context, the issue of amortization of deferred CCR remediation costs required to comply with EPA CCR requirements and CAMA is sui generis and distinguishable. These expenditures, as FERC and GAAP refer to them, are "costs" or an "asset" of remediation. They have been deemed by the Commission without objection as extraordinary, as not being recovered through current rates and have for those reasons been deferred. As such, they are investor-supplied funds; not ratepayer-supplied funds and under principles of equity, law and fairness are eligible for a return. Otherwise the investor supplying these funds is deprived of the time value of money and is inadequately compensated resulting in an increased risk and ultimately increasing the Company's cost of capital. The Commission in its discretion hereby authorizes a return, but discounts it as discussed below.

The nuclear discontinued plant costs, to the extent relevant to the issues in this case, are primarily so with respect to the Public Staff argument in support of equitable sharing. The Commission determines on balance that the support for equitable sharing the Public Staff argues these cases provide is unpersuasive. This is not to say that the Commission is of the opinion it could not approve an equitable sharing remedy in a given case outside the context of a nuclear plant discontinuance case, but this is not a nuclear plant discontinuance case and not one the Commission chooses to rely upon to authorize equitable sharing. The costs the electric utilities incurred at issue in those cases were for nuclear plants, that had they been placed on line and generated electricity would have been added to rate base as used and useful plant in service. Some of the costs were for plants actually placed on line but sized to serve more units than the units actually generating electricity and therefore constituted excess capacity or plant not "useful." The costs had never been placed in rate base as plant in service prior to the general rate cases at issue, and to the extent they were costs in abandoned nuclear facilities, they were facilities never used to generate electricity. Those are not the facts at issue here. None of the nuclear plant discontinuance cases either before the Commission or the courts on appeal held that to the extent a portion of the costs could be recovered, they were ineligible for any return on the undepreciated balance, just that the costs should not be added to rate base. In fact, in the past, the Commission has approved a return. Order dated September 24, 1982, Docket No. E-2, Sub 444. (Commission authorized recovery of costs associated with cancelled Harris Units 3 and 4 over a ten-year period with inclusion of the interest arising from the debt financing portion of the unamortized balance.)

The costs of the sewage treatment plant at issue in Carolina Water were classified as abandoned plant. The plant long having been in service had been taken out of service, and it would never be used again because service would be provided by contract with a governmental agency. A portion of the original costs to build the plant had not been recovered through depreciation at the time of abandonment. That is not the factual situation in this case. Here there is a deferral of ARO CCR remediation costs. New costs were incurred in 2015-2016 in addition to creation or maintenance of the impoundment in prior years.[1]

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[1] The issues of earning on the abandoned wastewater treatment plant was not the major issue before the Court in the Carolina Water case. The ultimate issue before the Commission was whether the unrecovered costs of the sewage treatment plant should be treated as plant held for future use of abandoned plant. Discussion of this issue consisted of less than two pages in a 126-page order. The monetary consequences amounted to a few thousand dollars per year. Docket No. W-354, Sub 111, Order dated July 31, 1992, pp. 56-58. The facts at issue in the case are unlikely to be repeated. Under the Uniform System of Accounts, the costs of individual components, in many instances, are

The MFG case is somewhat analogous, but does not address billions of dollars of CCR remediation costs incurred to comply with EPA and CAMA requirements accounted for in a deferred Commission approved ARO. The Commission is unable to discern whether the natural gas utility was required to construct lined landfills in which to place contaminated materials or construct caps over any existing repositories. The MFG case was a Commission decision, one the Commission may follow or not as it determines appropriate. For reasons fully explained herein, it determines not to follow it.

As to Public Staff arguments that the ARO costs or assets were all "capitalized expenses," the Commission, were it necessary to resolve this issue, would disagree. For example, a significant portion of the costs compiled in the asset retirement obligation has been or will be spent on creation of lined landfills with synthetic liners or impermeable caps over existing impoundments. These structures are examples of long-lived assets and are capital in nature- not expenses. Another significant portion, had they not been accounted for in an ARO and deferred, would have been operating or other expenses.[1] However, while expenditure of costs outside of the ARO context that are deferred may include what otherwise would be classified as "expenses," e.g., operating costs, when they are capitalized and by order of the Commission are deferred, they lose for ratemaking purposes the attributes of test year recurring "expenses" deemed recoverable through the rates then in effect that do not qualify for a return. To the extent they qualify for recovery "of" (versus recovery "on") test year expenses in a general rate case through N.C. Gen. Stat. § 62-133(b)(3), they are recoverable as "actual investment currently consumed through reasonable actual depreciation" (amortization) rather than traditional test year, recurring "reasonable operating expenses." The Commission determines that while sui generis these ARO costs in totality are more closely related to deferred production plant costs than deferred storm damage costs, for example.

In Footnote 2 on page 5 of the Public Staff brief, the Public Staff contends:

> [2] Thornburg I provides that the Commission has discretionary authority to award or deny a return on the unamortized balance. A subsequent decision of the North Carolina Supreme Court indicates such deferred operating expenses are not eligible for a return on the unamortized balance: "Costs for abandoned property may be recovered as operating expenses through amortization, but a return on the investment may not be recovered by including the unamortized portion of the property in rate base." State ex rel. Utils. Comm'n v. Carolina Water Serv., 335 N.C. 493, 508 (1994) (Carolina Water Service). This decision did not expressly overrule Thornburg I, but nonetheless suggests that a return on unamortized balance of a regulatory asset is not a discretionary matter for the Commission; instead it

combined into classes for calculating depreciation rates and net salvage value. Within these classes many individual components retire before or after the end of their projected useful lives. These retirements affect the recalculated depreciation rates, but the individual components are not classified as abandoned plant. See Tr. Vol. 2, Doss Ex. 3. Hahne & Aliff, Accounting for Public Utilities § 6.04 pp. 6-8, 6-10, § 6.05[3] pp. 6-12.

[1] 2016 is the twelve month test year in this case. To the extent the Commission had not authorized deferral of the ARO in 2016, the non-capital portion of the CCR remediation costs to the extent reasonable and prudent would be recoverable dollar-for-dollar in the revenue requirement. The portion spent on capital projects to the extent comprising completed projects would be added to rate base and eligible to earn a return.

may be prohibited by law.[1] For purposes of the present Post-Hearing Brief, the Public Staff position is that under either the Thornburg I holding or the Carolina Water Service holding, there is no DEC entitlement to a return on the unamortized balance of its deferred coal ash costs.

The Commission finds the contention inaccurate that the cited cases deny the Commission discretion to authorize a return on a deferred CCR remediation ARO. The nuclear plant discontinuance costs at issue in Thornburg I were not "deferred operating expenses" like deferred CCR ARO costs, and the abandoned water treatment plant costs at issue in Carolina Water likewise were not deferred "regulatory asset" costs comparable to either deferred nuclear plant discontinuance costs or deferred CCR ARO costs.[2] The Commission notes that it has authorized deferral of capital costs in utility plant (e.g., combined cycle natural gas fired electric generating plants) completed and placed in service prior to the test year or prior to the end of the test year of a general rate case to prevent loss of recovery of costs. The costs so deferred are not test year recurring operating expenses but deferred capital costs, added to rate base and eligible for a full return. A used and useful analysis is appropriate to determine recovery of these costs. Docket No. E-22, Sub 532 (Dec. 22, 2016) (2016 DNCP Rate Order)

The Public Staff also argues inaccurately and misleadingly that "it generally makes no regulatory sense to defer to a regulatory asset a cost that could be placed in rate base – deferral is used when necessary to prevent significant erosion of earnings, which is applicable to expenses but not to property that can be put in rate base; . . . ." In the Commission's December 22, 2016 order in the most recent DNCP general rate case, Docket No. E-22, Sub 532, the Commission approved a stipulation between the Company and the Public Staff to defer the post-in-service costs of the Warren County CC and the Brunswick County CC. These plant-in-service electric production assets had been placed in service prior to the end of the general rate case test year, and the deferral postponed the date on which depreciation costs began and permitted return on the full costs of the assets. This deferral related to property, not expenses.

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[1] While the Public Staff suggests that authorizing a return on the unamortized balance might not be discretionary, this suggestion is belied by the Public Staff's alternative remedy for disallowing CCR remediation costs set forth on page 422 of its proposed order:

> Consequently, the Commission in the exercise of its judgment and discretion, determines that a management penalty in the approximate sum of $72.3 million is appropriate with respect to DEC CCR remediation expenses accounted for in the earlier established ARO with respect to costs incurred through the end of the test year as adjusted. . . . Had the Commission not imposed this penalty, the deferred coal ash costs would have been amortized over five years with a full authorized return on the unamortized balance. The penalty will be imposed by reducing the resulting annual amortization expense by approximately $14.46 million (from the return on the unamortized balance in the rate base portion) for each of the five years, resulting in an approximate $72.3 million management penalty.

[2] While the regulatory accounting concepts of creation of a "regulatory asset/liability" and "deferral" include a wide spectrum of cost categories, this Commission views differently costs incurred before the test year of a general rate case (like extraordinary storm costs) and costs otherwise recognizable as test year costs or expenses but deferred for non-traditional future recovery such as nuclear plant discontinuance costs that are not added to rate base but are nonetheless amortized over future years. Costs in the former category are deferred to prevent loss of recovery. Costs in the latter category generally are deferred to limit, reduce or postpone recovery.

From the outset, the Public Staff has acknowledged and recognized that the ARO costs do not fit into traditional categories: "The Public Staff believed that the non-capital costs and depreciation expense related to compliance with state and federal requirements ... these very unique deferred expenses . . . the unusual circumstances of these costs . . . the unique nature of the costs and the complexity of the issues surrounding the determination of ultimate rate recovery." Tr. Vol. 18, pp. 300-01, Docket No. E-2, Sub 1142.

In the Commission's attempt to obtain a classification of the types of costs included in the ARO in the DEP case, witness Maness listed among others, site preparation, site infrastructure, construct a landfill, cap-in-place, capital expenditures related to equipment and facilities." Tr. Vol 19, p. 58. Under any analysis, these are not expenses but capital items. Had DEC not sought establishment of an ARO and deferral, it is incorrect that they would not have been added to plant in service and depreciated over their useful lives.

In Docket No. E-2, Sub 1142, witness Maness was asked why certain ARO capital costs were not appropriately classified as used and useful.

Q. Just to be clear, one of the things we are doing -- we showed it up on the screen here yesterday - we are putting liners under these coal ash pits, right?
A. Yes, sir.
Q. And that's - and we are putting caps or proposing to put caps over some coal ash basins?
A. Yes.
Q. Isn't that used and useful expenditure to keep the coal ash where it belongs?
A. Well, that raises a number of interesting questions, and I can't pretend to be able to answer them in detail. I have been searching for some answers in the accounting literature and haven't found anything direct yet."
Tr. Vol. 19, pp. 65-66.

Upon being questioned and when given the opportunity to support its position that the deferred ARO costs are "expenses," the Public Staff simply was unable to do so.

When witness Maness was asked whether classifying the ARO costs as used and useful made any difference to the outcome of the case, he responded, "I don't think it makes any difference in this case." Tr. Vol. 19, p. 66. The Commission agrees.

The Commission does agree with the Public Staff and others that even if the ARO deferral costs are found used and useful and that a 9.9% rate of return on rate base is appropriate, the Commission nevertheless has authority to disallow a portion of the return on the ARO costs due to mismanagement. This is what the Commission has required, and it is legally justified in doing so.

As expressed through witness Maness' testimony, the Public Staff looks to the Commission's Order Granting Partial Increase in Rates and Charges in Docket No. E-2, Sub 526 (Aug. 27, 1987) (1987 DEP Rate Order) and its affirmance by the Supreme Court in Thornburg I, 325 N.C. 463, 385 S.E.2d 451 (1989) as precedent for its equitable sharing concept. The Commission determines that Thornburg I provides less support for the equitable sharing the Public

Staff advocates when viewed within the context of other cases addressing nuclear plant discontinuance costs. Greater context is found in Thornburg II, the 1988 DEP Rate Order and the Commission's Order Denying Motions for Reconsideration in the 1988 DEP Rate Case (Docket No. E-2, Sub 537) (1988 DEP Reconsideration Order), and the Supreme Court's reversal in part of those orders in Thornburg II, 325 N.C. 484, 385 S.E.2d 463 (1989).

The principal issue in the 1987 DEP Rate Case/Thornburg I was whether the Company could recover in rates any portion of the costs associated with the abandoned Units 2, 3, and 4 of the Shearon Harris nuclear plant. The Commission had previously decided that the Company could amortize the costs associated with these abandoned units over a ten-year period, but that "no ratemaking treatment should be allowed which would have the effect of allowing ... [the Company] to earn a return on the unamortized balance." 1987 DEP Rate Order, p. 61. Over the objections of the AGO, the Commission decided to continue to follow that process in the 1987 case – it allowed amortization of abandonment costs over a ten-year period, what the court classified as an operating expense[1] for the purposes of rate recovery under N.C. Gen. Stat. §§ 62-133(b)(3) and 62-133(c), but no return. The Supreme Court, in a passage extensively quoted in witness Maness' testimony (Tr. Vol. 22, pp. 75-76), affirmed the Commission's decision, holding that N.C. Gen. Stat. §§ 62-133(b)(3) and 62-133(c) were elastic enough to include non-recurring abandonment costs as utility test year "expense," and that N.C. Gen. Stat. § 62-133(d), which allows the Commission to factor in "all other material facts of record that will enable it to determine what are just and reasonable rates," also provided support for the Commission's decision. The Court further held that as a matter of policy a return of, but not a return on, the abandonment costs was appropriate. Thornburg I, 325 N.C. at 476-81, 385 S.E.2d at 458-61. The Commission had not authorized a return on the costs at issue. The contested issue was recovery of not recovery on the nuclear investment costs.

In Thornburg I, the Court held specifically that the Commission's recovery of but no return on decision was "within the Commission's discretion" and would not be disturbed. Id. at 481. That decision effected a "sharing" between the Company's shareholders, on the one hand, and its customers, on the other – shareholders received a return of the costs, but no return on the costs. It is based upon this holding that the Public Staff, through witness Maness' testimony, contends that "reasonable rates can include a sharing between ratepayers and investors with regard to plant cancellation costs" (Tr. Vol. 22, p. 75), and that the Commission possesses discretion to implement this sharing.

There are, however, distinctions between the 1987 DEP Rate Case/Thornburg I and the present case. First this case does not involve "abandoned plant" or cancellation costs. Rather, it involves an asset retirement obligation and whether or not the unamortized balance is eligible for a return. As such, the authority that the Public Staff relies upon to support its "equitable sharing" concept is not directly on point. This is illustrated by examining the prior orders of this

[1] While the Court's use of the term "operating expense" is technically correct as referenced in the statute, the more precise term should have been "actual investment currently consumed through reasonable actual depreciation" (amortization) in N.C. Gen. Stat. § 62-133(b)(3). The costs at issue are not recurring operating and maintenance or other "expenses" expended in the test year. They are ever decreasing costs allowing a "return of," but not a "return on" the nuclear plant costs. See Tr. Vol. 9, pp. 115-131; Vol. 10, pp. 14-28.

Commission and the subsequent Thornburg case: the 1988 DEP Rate Order, the 1988 DEP Reconsideration Order, and Thornburg II.

In the 1988 DEP Rate Case, the principal issue for decision was the reasonableness and prudence of the costs of constructing and placing into service Unit 1 of the Shearon Harris nuclear plant. The Commission found that for the most part, Harris Unit 1 costs were reasonable and prudent, and that determination in the 1988 DEP Rate Order was upheld by the Supreme Court. Thornburg II, 325 N.C. at 488-89, 385 S.E.2d at 465-66 (finding "no error" in that part of the Commission's Order). However, a part – $570 million-worth – of the costs the Commission considered were incurred in connection with facilities to be shared with Units 2, 3, and 4, units that the Company had ceased to construct to completion. The Commission found that while these $570 million in costs were prudently incurred, they should be shared between the Company's customers and its shareholders. The Commission found that approximately $180 million of those costs were properly classified as "abandonment" costs and should be borne by shareholders. 1988 DEP Rate Order, pp. 112-14. The remaining $390 million were left in rate base.

Responding to the Public Staff's request that the Commission reconsider this decision and remove the entire $570 million from rate base on the grounds that all of it related to abandoned plant, the Commission reaffirmed its decision in the 1988 DEP Reconsideration Order and provided additional explanation for its ruling. It stated that the Public Staff's request that the full $570 million for the common facilities be treated as abandonment costs was based upon a "misunderstanding" of the 1988 DEP Rate Order and the Commission's objective in splitting this $570 million item into $390 million of rate base and $180 million of cancellation costs. 1988 DEP Reconsideration Order, pp. 2-3. The Commission did not (it says in the 1988 DEP Reconsideration Order) intend to treat the "excess common facilities" as abandoned plant; rather, it effected an "equitable sharing" (emphasis added) of the $570 million between customers and shareholders. The Commission reiterated that the Company's choice of the cluster design – which engendered the shared facilities – was reasonable and prudent, and that except as specifically indicated in the 1988 DEP Rate Order, the costs of the Shearon Harris plant were "reasonable and prudently incurred." Thus, the Commission found, the $570 million at issue was also reasonably and prudently incurred.

Nevertheless, the Commission held, (id. at 4-5), that it was appropriate to share the $570 million at issue, and it indicated that it came up with the allocation (essentially one-third to cancellation costs and two-thirds to rate base) on its own and adopted it "for reasons of fairness and equity." The Commission held that it continued "to believe that a reasonable and equitable apportionment of the burden and risks associated with ... [the Company's] prudent investment in common facilities is appropriate." It stated further that its assignment of $180 million as the value of the Company's prudent investment in common facilities to be treated as cancellation costs for ratemaking purposes was an appropriate exercise of its "regulatory discretion."

The Supreme Court disagreed. It held that the Commission did not have the discretionary power to effectuate its "equitable sharing" decision. Rather, the facilities were either "used and useful," and therefore in rate base, or they were not. The Court looked to the Commission's finding that the facilities in question were "excess common facilities," and held that "excess" facilities were not "used and useful" as a matter of law. Thornburg II, 325 N.C. at 495. Accordingly, looking to the broader spectrum of Commission and Supreme Court precedent, the Commission determines not to approve the Public Staff's "equitable sharing" concept through reliance on the nuclear plant discontinuance cost cases.

4. ARO Accounting and "Used and Useful"

In the 2018 DEP Rate Case, the Public Staff argued that the Commission had the discretion to implement the "equitable sharing" concept based upon the Public Staff's interpretation of prior Commission orders and decisions of the North Carolina Supreme Court that permit equitable sharing in the case of abandoned nuclear plants or long out-of-use manufactured gas plants. As noted above and in the 2018 DEP Rate Order, the Commission determines not to approve the Public Staff equitable sharing recommendation. In the 2018 DEP Case, the Commission held to the contrary that

> Costs placed in an ARO account are eligible for deferral and amortization and for earning on the unamortized balance. As such, even if the remediation costs are ARO expenditures, they are eligible for ratemaking treatment as though they are used and useful assets.

2018 DEP Rate Order, p. 196. In this case, Public Staff disputes this as a matter of accounting, and concludes on the basis of its interpretation of the accounting standards that the Company's coal ash basin closure expenditures cannot be classified as "used and useful." As it did in the 2018 DEP order, the Commission determines that it can authorize a return on the unamortized ARO costs.

The Public Staff's position is advanced by witness Maness. Starting from the premise that the Company "chose" to account for its coal ash basin closure costs through ARO accounting, witness Maness makes three basic points. First, he indicates that the Company's deferred coal ash basin closure costs placed in the ARO are more properly categorized as deferred expenses, in that the ARO is "a regulatory accounting and ratemaking method that does not explicitly account for any coal ash compliance costs, either in the past or in the future, as the capitalized costs of property, but instead accounts for them as ongoing expenses ...." Tr. Vol. 22, p. 79. Second, he states that the fact that the Company classifies these costs as "working capital" is irrelevant, and merely a matter of convenience. Id. at 81. Third, he asserts that these costs cannot possibly be classified as "used and useful," because (in his view) that term applies only to utility plant, not expenses. Id. at 77. The Commission disagrees, but as the Public Staff agrees that the Commission possesses the discretion to approve a return on the unamortized balance of the deferred CCR remediation ARO costs, the Commission finds the debate for purposes of this case to be for the most part an academic one.

First, the Commission disagrees that the Company "chose" ARO accounting. The Commission has already so held in the 2018 DEP Case: "Once it became clear that the new laws and regulations governing coal ash would require closure of the Company's existing coal ash basins, GAAP required that an ARO be established, and the Company had no choice in the matter." 2018 DEP Rate Order, p. 194.[1] Further, as Company witness Doss testified, in addition to

[1] As the Public Staff and the Commission have noted previously, "Statements of the FASB are officially recognized by the Securities and Exchange Commission (SEC) as authoritative with regard to GAAP in the United States, and the requirements included in those Statements are essentially mandatory for any publicly traded entity."

GAAP requirements "the Company was also required to (and did) adhere to and apply the accounting guidance under ... [the] Federal Energy Regulatory Commission ('FERC') Code of Federal Regulations ('CFR'), as well as Orders of this Commission." Tr. Vol. 12, p. 62. The Company's ARO accounting complies with the authoritative statements of GAAP, FERC, and this Commission.

Witness Doss provided an extended explanation of the GAAP, FERC, and deferral directives that govern the manner in which the Company established the ARO and has accounted for coal ash basin closure costs in the ARO. The Commission credits his explanation and testimony, which are un-contradicted.

a. GAAP

The CCR Rule and CAMA were new laws that compelled basin closure under GAAP.[1] As Company witness Doss indicated, "The closure obligation triggered ARO accounting requirements." Tr. Vol. 12, p. 63. He elaborated:

> Statement of Financial Accounting Standard ("SFAS") No. 143 (now codified as ASC 410) was effective for and implemented by the Company in 2003 for financial reporting purposes. This guidance requires recognition of liabilities for the expected cost of retiring tangible long-lived assets for which a legal retirement obligation exists. GAAP (in ASC 410-20-20) refers to these costs as an "Asset Retirement Obligation" or an ARO, and defines a "legal obligation" as an "obligation that a party is required to settle as a result of an existing or enacted law ...." (Emphasis added). Each of CAMA and the CCR Rule qualify as an "enacted law" under this guidance.

Id. As he explained further (id. at 64-65), GAAP requires ARO accounting for the closure costs under ASC 410-20-15. Specifically, Subtopic 15-2 indicates that the guidance applies to the following transactions and activities:

a) Legal obligations associated with the retirement of a tangible long-lived asset that result from the acquisition, construction, or development and (or) the normal operation of a long-lived asset, including any legal obligations that require disposal of a replaced part that is a component of a tangible long-lived asset.
b) An environmental remediation liability that results from the normal operation of a long-lived asset and that is associated with the retirement of that asset. The fact that partial settlement of an obligation is required or performed before full retirement of an asset does not remove that obligation from the scope of this Subtopic. If environmental contamination is incurred in the normal operation of a long-lived asset and is associated with the retirement of that asset, then this Subtopic will apply (and Subtopic 410-30 will not apply) if the entity is legally obligated to treat the contamination.

See Order Granting in Part and Denying in Part Request for Deferral Accounting, Docket E-7, Sub 723 (April 4, 2003), pp. 11-12.

[1] The applicable GAAP guidance is contained in Doss Rebuttal Ex. 1.

c) A conditional obligation to perform a retirement activity. Uncertainty about the timing of settlement of the asset retirement obligation does not remove that obligation from the scope of this Subtopic but will affect the measurement of a liability for that obligation (see paragraph 410-20-25-10).

Here, the coal ash basins being retired are tangible long-lived assets, and so Subtopic 15-2(a) applies. In addition, to the extent that retirement involves any environmental remediation, that remediation is the result of the normal operation of the basins, which is the subject of Subtopic 15-2(b). As noted in Company witness Kerin's testimony, the use of ash impoundments as a storage location for coal ash and other CCR was in accordance with industry standards and then-applicable regulations. Finally, under Subtopic 15-2(c), the retirement requirements are a conditional obligation to perform a retirement activity as the nature, timing and extent of the closure depends on various determinations. In CAMA those determinations revolve around the legislative or the North Carolina Department of Environmental Quality assessed risk rankings. Under the CCR rule, those determinations revolve around the evaluation of certain criteria by specific deadlines.

Upon recognition that ARO accounting is required, GAAP further indicates that the entity "shall capitalize an asset retirement cost by increasing the carrying amount of the related long-lived asset by the same amount as the liability." ASC 410-20-25-5; see also Tr. Vol. 12, p. 20.

The reference in ASC 410-20-15-2(b) to environmental compliance costs in connection with "normal operation" highlights an important distinction in this case with respect to the Company's coal ash basin closure costs. GAAP distinguishes between costs associated with "normal" and "costs associated with improper" operation. The Company has demonstrated that "normal" operation applies.

The distinction is detailed in witness Doss' testimony. Subtopic 410-20 of the ARO guidance applies to "normal operation" (see ASC 410-20-15-2(b); Doss Rebuttal Ex. 1, p. 2 of 28), and permits their inclusion in an ARO. Subtopic 410-30 applies to improper operation (see ASC 410-20-15-3(b); Doss Rebuttal Ex. 1, p. 2 of 28), and excludes them from an ARO. For example, as witness Doss testified, "Costs associated with the Company's Dan River spill ... are covered by Subtopic 15-3(b), and, therefore, are not included in the coal ash basin closure ARO." Tr. Vol. 12, p. 66. This comports with the GAAP guidance itself, which notes that "a certain amount of spillage may be inherent in the normal operations of a fuel storage facility, but a catastrophic accident caused by noncompliance with an entity's safety procedures is not." See ASC 410-20-15-3(b); Doss Rebuttal Ex. 1, pp. 2-3 of 28. The guidance notes further that the spillage costs are properly within the ARO, while costs resulting from the catastrophic accident are excluded. Id.

GAAP guidance notes that "whether an obligation results from the normal operation of a long-lived asset may require judgment." See ASC 410-20-55-7; Doss Rebuttal Ex. 1, p. 11 of 28. Witness Doss acknowledged this. Tr. Vol. 12, p. 111. But it is not unbridled or arbitrary judgment. To the contrary, the exercise of judgment is carefully circumscribed through internal and external controls.

Witness Doss described these controls at length in his testimony. He noted that "DEC has implemented a Coal Ash ARO Charging Committee whose purpose is to evaluate costs to be incurred for determination as to whether they qualify for ARO accounting treatment ... [and that decisions] of the Coal Ash ARO Charging Committee are summarized in a charging guidelines document." Id. at 66-67. These decisions are reviewed internally by the Company's "Coal Combustion Products (CCP) group to ensure that 1) all relevant facts were appropriately communicated by CCP and understood by the Committee, and 2) that the CCP group understands the decisions to properly categorize actual project costs." Id. at 67. Finally, any ARO-related cost classification is also reviewed by the Company's external auditor, Deloitte & Touche LLP, which in the course of its annual audit issues its opinions that the Company's financial statements are presented fairly in all material respects and in accordance with GAAP, and that the Company has effective internal control over financial reporting. Id. at 67-68.

The Commission determines that the evidence that the coal ash basin closure costs incurred by the Company, and for which it seeks recovery in this case, result from the "normal," non-catastrophic operation of the Company's coal ash basins is compelling. It is detailed above in connection with the Commission's discussion of the Company's prima facie case, and need not be repeated. The Company has demonstrated that its coal ash management practices, storage of CCR in unlined ash basins, complied with the then-applicable regulations and with industry practice. Seepage from unlined basins is therefore part of the "normal operation" of those basins.

b. FERC

Witness Doss also explained the FERC accounting guidance. He noted that the Company is regulated by FERC, and therefore required to use the FERC Uniform System of Accounts, which states, in relevant part:

> An asset retirement obligation represents a liability for the legal obligation associated with the retirement of a tangible long-lived asset that a company is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel. An asset retirement cost represents the amount capitalized when the liability is recognized for the long-lived asset that gives rise to the legal obligation. The amount recognized for the liability and an associated asset retirement cost shall be stated at the fair value of the asset retirement obligation in the period in which the obligation is incurred.

Tr. Vol. 12, p. 68. He noted further that the FERC Uniform System of Accounts General Instruction No. 25 requires that:

> a utility initially record a liability for an ARO in Account 230 — Asset Retirement Obligations, and charge the associated asset retirement costs to the electric utility plant that gave rise to the legal obligation in Account 101- Electric Plant in Service. The asset retirement cost is to be depreciated over the useful life of the related asset that gives rise to the obligation by recording a debit to Account 403.1- Depreciation Expense for Asset Retirement Costs and a credit to Account 108 Accumulated Provision for Depreciation of Electric Utility Plant. In periods

> subsequent to the initial recording of the ARO, the utility shall recognize the period-to-period changes of the ARO that result from the passage of time due to the accretion of the liability by recording a debit to Account 411.10 — Accretion Expense, and a credit to Account 230.

Id. at 68-69.

Commission's Deferral Order and Summary of Accounting Rules and Deferral

In 2003, after the Financial Accounting Standards Board required the implementation of the ARO accounting guidance, the Commission ruled in Docket No. E-7, Sub 723 "That the implementation of SFAS 143 [now codified as ASC 410] for financial reporting purposes and the deferrals allowed in this docket shall have no impact on the ultimate amount of costs recovered from the North Carolina retail ratepayers for nuclear decommissioning or other AROs, subject to future orders of the Commission." See Order Granting Motion for Reconsideration and Allowing Deferral of Costs, Docket E-7, Sub 723 (August 8, 2003), p. 12. As witness Doss explains,

> The cash outflows to settle the ARO are not recorded as an expense of DE Carolinas. The Company has already recognized depreciation expense through the life of the asset and accretion expense over the period of expected settlement of the ARO, and these costs were capitalized previously as part of the Asset Retirement Cost related to the ARO. See ASC 410-20-25-5. However, in the case of DE Carolinas and pursuant to the Commission's Order in Docket No. E-7, Sub 723, the depreciation and accretion expenses were deferred. The amount spent related to the coal ash basin closure ARO is effectively the portion of the deferred depreciation and accretion expense which has now been incurred as a cash outflow and which is "subject to the future orders of the Commission" as stated in the Order. Therefore, the Company's deferral request of costs incurred and the recovery request in this rate case are in accordance with the deferral Order the Commission issued in Docket No. E-7, Sub 723.

Tr. Vol. 12, p. 70.

While the accounting rules detailed herein are complex, in simplified terms, both GAAP and FERC accounting guidance require the recognition of a liability (the ARO) upon the requisite triggering event – the legal obligation to retire the Company's coal ash basins. Recognition of the liability carries with it recognition of a corresponding asset – the capitalized cost of settling the liability, which under both GAAP and FERC rules is considered part of the property, plant and equipment for the assets that must be retired. While under ordinary circumstances these recognition events would be reflected over time in the Company's income statements, because of the deferral order in Docket No. E-7, Sub 723, the income statement impacts are deferred into regulatory assets "pending further orders of the Commission." The Company in this case is seeking such a further order, so as to reflect in rates the outflow of cash that it has incurred – and that its investors have funded – as it proceeds to settle the asset retirement obligation created by the CCR Rule and CAMA.

c. The Savoy Letter

The Company's accounting of its coal ash costs has not occurred in a vacuum. Over 20 months before DEC filed its application to increase rates in this docket, it sent a letter to the Commission, copying the Public Staff, in which the Company detailed exactly how it was accounting for its coal ash basin closure costs. See Letter dated December 21, 2015 from Brian D. Savoy, the Company's SVP, Chief Accounting Officer, and Controller to Gail L. Mount, Chief Clerk (Savoy Letter), filed in Docket No. E-7, Sub 1110.[1] The Savoy Letter:

- Describes the GAAP and FERC accounting requirements regarding AROs;
- Describes the triggering events for the creation of the ARO, noting the promulgation of the CCR Rule and the passage of CAMA;
- Indicates that an ARO related to the closure of coal ash basins was recorded on the Company's balance sheet;
- Indicates further that a corresponding asset was recorded "as part of the associated coal plant in the property, plant and equipment (PP&E) accounts, or if associated with a retired coal plant, recorded in regulatory assets"; and
- Noted that "[c]onsistent with the requirements of the Commission's Order dated August 8, 2003 in Docket No. E-7, Sub 723 ... all income statement impacts relating to the AROs ultimately reside in regulatory asset accounts."

Witnesses Fountain and McManeus were examined at length regarding the Savoy Letter at the evidentiary hearing. Tr. Vol. 9, pp. 117-24. That examination established, inter alia, that basin closure costs, whether they be denominated capital costs, O&M costs, general administration costs are nevertheless capitalized in connection with the establishment of the ARO; that such costs are extraordinary and not reflected in the Company's then-current rates; and, therefore, needed to be set aside and deferred so that the Company would not lose recovery of those costs "to the detriment of the stockholder." Id. at 123-24.

No party takes issue with the Company's accounting of coal ash basin closure costs in an ARO, as detailed in the Savoy Letter. Certainly, the Public Staff does not – witness Maness' testimony does not challenge the basis for or the propriety of the accounting treatment, he comes to a different conclusion regarding the effect of such treatment upon the Company's entitlement versus its eligibility to earn a return on the unamortized balance of those costs. As noted previously, Intervenors have a burden of production when challenging the Company's costs. This principle equally applies to the accounting for costs. The Commission determines that the Company has met this burden. The Public Staff challenge makes the issue ripe for the Commission to address the issue on the merits. The Company has met its burden of showing that the costs it seeks to recover are not only reasonably and prudently incurred, but also appropriately accounted for in ARO

[1] This Docket was established on March 28, 2016 by order of the Commission, and the Savoy Letter placed therein, so as to acknowledge the Letter and allow other parties with interest to be made aware of it. See Order Acknowledging Receipt of Filing, Docket No. E-7, Sub 1110 (Mar. 28, 2016). The order recited that no filings were made in response to the letter as of the time the Docket was established, and indeed, no substantive filings were made thereafter until the Company filed its Petition for Accounting Order on December 30, 2016, formally seeking deferral of coal ash basin closure costs. The Sub 1110 Docket has been consolidated with this rate case docket.

accounting, and the Commission agrees that based on its determinations on the merits that recovery is appropriate except as addressed below.

Several consequences flow from this determination. First, deferred costs are costs "that have been paid for by the ... [utility] but have yet to be included for ratemaking purposes ...." Lesser & Giacchino, p. 52. Through the Savoy Letter, the Company told the Commission and the Public Staff, and the Commission told all interested parties, exactly how the Company's coal ash basin closure costs were being accounted for, and explicitly indicated that the costs were being deferred pursuant to the Commission's orders in Docket No. E-7, Sub 723. Neither the Public Staff nor anyone else, including the AGO, raised any objection.

Nor did the Public Staff or the AGO raise any objection when the Company made its formal deferral request in 2016. Tr. Vol. 9, p. 126. The Public Staff however asserts that deferral for regulatory accounting purposes is appropriate, given the magnitude of the costs and their potential impact upon the authorized rate of return. The nature of the deferral is such that all costs, no matter how classified, related to the Company's coal ash basin closure obligations are accounted for in the ARO. Id. p. 125. The ARO was established for this purpose, as the Savoy Letter makes clear. As such, the Commission determines that even were it necessary to resolve this issue, witness Maness' classification of these costs as "deferred expenses" is not persuasive, not supported by authority and not determinative, given the nature of deferral.

It is also incorrect as a matter of accounting. As witness Doss testified, "The Company has accounted for these costs as required under GAAP and FERC Uniform System of Accounts." Tr. Vol. 12, p. 71. Under GAAP, the costs (no matter what their classification) are capitalized pursuant to ASC 410-20-25-5. Id. at 70. Under FERC accounting, they are capitalized as well. Id. at 68-69. Accordingly, when properly accounted for in an ARO, the specific classification of costs is not determinative, because under GAAP and FERC guidance ARO costs are capitalized. The nomenclature relied upon in GAAP and FERC is costs, assets, and liabilities, not "expenses."

Likewise, witness Maness' criticism that these costs are placed in "working capital" is also not determinative. Witness Maness, without support and solely as a matter of opinion, states that the Company's inclusion of the deferred balance of coal ash basin closure costs in the "working capital" portion of rate base is merely a matter of convenience. Tr. Vol. 22, p. 81. He does not state that their inclusion in working capital is incorrect, merely that such inclusion is not determinative of the issue of whether the Company is entitled to a return on the unamortized balance. It appears that witness Maness has misunderstood the Company's position, as is evident from the testimony of witness McManeus, which the Commission also credits. She testified:

> [I]t is important to recognize that rate base represents the amount of funds supplied by investors. Such funds have been advanced for many purposes. Certainly, construction of electric plant is one such purpose, but there are others – for example, to purchase fuel inventory, to provide cash working capital, etc. Further, to accurately determine the amount of investor-supplied funds, one must consider whether any amounts that have been used for such purposes have been advanced by customers, rather than investors. In this particular case, investors have advanced funds to pay for coal ash compliance costs.

Tr. Vol. 6, p. 317. She elaborated further, indicating that the "characteristic that makes the deferred coal ash cost a legitimate component of rate base" is the fact that the funds used to pay those costs were supplied by investors. Id. at 318.

The point of a deferral is that the costs to be deferred are of a magnitude that they need to be taken out of the normal ratemaking accounting process and set to one side for later inclusion in rates, lest the Company lose its ability to recover them. Tr. Vol. 9, pp. 123-24. Should the Company's ability to recover such costs be impaired, it will not be able to earn at its authorized rate of return. Id. at 124. Setting them to one side means that unless a return is allowed, the Company's ability to earn its authorized rate of return is again impaired. Further, if in the process of bringing the deferred costs into rates the costs are amortized over a period of years, not allowing a return on the unamortized costs again impairs the Company's ability to earn at its authorized rate of return. Rates that impair the Company's ability to earn its authorized return are not just and reasonable, unless the Company should be penalized due to mismanagement, for example, and the Commission would act contrary to law were it to order them.

Finally, the Public Staff's notion that costs accounted for in an ARO, at least to the extent they relate to long lived capital assets, are expenses and therefore ineligible to be characterized as "used and useful" is inconsistent with ARO accounting, and also inconsistent with the law. The Commission has already decided that the Public Staff's legal position that "used and useful" property is confined to "plant" is incorrect. It held in the 2018 DEP Rate Case:

> As a matter of law, it is not necessary that something be classified as "plant" in order to be properly included in rate base. Rather, the issue is the source of the funds. In State ex rel. Utils. Comm'n v. Virginia Elec. & Power Co., 285 N.C. 398 (1974) (VEPCO), for example, the Supreme Court held that working capital (which is not "plant") could be included in rate base, so long as it was provided by the utility:
>
> > Like any other business, a public utility must at all times have on hand a reasonable amount of materials and supplies and a reasonable amount of funds for the payment of its expenses of operation. While Chapter 62 of the General Statutes makes no reference to working capital, as such, the utility's own funds reasonably invested in such materials and supplies and its cash funds reasonably so held for payment of operating expenses, as they become payable, fall within the meaning of the term "property used and useful in providing the service" ... and are a proper addition to the rate base on which the utility must be permitted to earn a fair rate of return.
> >
> > Conversely, the utility is not entitled to include in its rate base funds which it has not provided but which it has been permitted to collect from its customers for the purpose of paying expenses at some future time and which it actually uses as working capital in the meantime.
>
> 285 N.C. at 414-15. As the Company appropriately accounted for coal ash basin closure costs in the working capital section of rate

> base, and as these funds were investor-furnished, not customer-furnished, VEPCO holds that they are "used and useful" within the meaning of N.C. Gen. Stat. § 62-133(b)(1) in the provision of service. As such, the Company is entitled to earn a return on those funds over the period in which the costs are amortized.

2018 DEP Rate Order, pp. 194-95.

In addition, however, witness Maness is incorrect in his view of the appropriate accounting outcome. He indicates, "It is appropriate to state that the actual costs capitalized by a utility as the costs of used and useful property itself may be included in rate base and thereby earn a return, as long as those costs are reasonable and prudently incurred, and are intended to provide utility service in the present or in the future; however, the expenses of operating and maintaining that property in the present or in the future do not get capitalized as part of the cost of the property." Tr. Vol. 22, pp. 77-78 (emphasis added.) It is less than clear what witness Maness means by this qualification.

However, as witness Doss testified, in ARO accounting, "Under both GAAP and FERC guidance the asset created when a Company initially recognizes an ARO is considered part of the property, plant and equipment for the assets which must be eventually retired." Tr. Vol. 12, p. 71 (emphasis added.) Accordingly, such costs are used and useful in that they are intended to provide utility service in the present or in the future through achieving their intended purpose: environmental compliance, the retirement of the ash impoundments and the final storage location for the residuals from the generation of electricity. As witness Doss concluded, "The achievement of those three purposes is used and useful as the utility has the obligation to comply with CAMA and the CCR Rule." Id. at 73.

When the coal ash basins at issue in this matter were constructed, they were capital assets "used and useful" in the provision of service to customers – their function was to store coal ash, a byproduct of the generation of electricity. Even if closed as a result of CAMA and the CCR Rule, the basins at all but high priority sites will remain, although they may be capped in place or have other remedial measures taken to comply with the current regulatory requirements. As such, they will remain used and useful, because they will still store coal ash, a byproduct of electricity generation. The basins at high priority sites will no longer exist, but in the case of Dan River, a new landfill is being constructed, which is a capital asset and used and useful – it, too, will store coal ash. The landfill will have a long-lived synthetic liner, a cost that even outside the concept of ARO accounting is not an "expense." Other expenses of a more O&M or general administration variety were incurred yet deferred under the deferral orders of this Commission, meaning that the Company is afforded the opportunity to recover them in rates at a later time. The funds used to pay for those costs were furnished by the Company and its investors, and the costs are eligible for a return on, not merely a return of, those funds, lest its earnings be impaired. In this sense, just like "classic" working capital, these funds are "property" of the Company, used and useful in the provision of electric service to its customers. Such funds, properly accounted for in an ARO, are eligible "deferral and amortization and for earning on the unamortized balance." The Commission so orders in this case.

The question to be decided is the amount of the funds so eligible. That depends upon the Commission's analysis of the reasonableness and prudence of the costs incurred.

5. Procedure for Establishing the Deferral

The AGO, in its brief, argues that establishment of the ARO is unlawful on several grounds. The AGO argues that the 2015-2017 CCR remediation costs accounted for in the ARO if recovered through rates constitute retroactive ratemaking. The AGO argues that the deferral should not be permitted because DEC failed to obtain prior approval. The AGO argues that deferral of the CCR remediation costs does not meet the test established by the Commission because DEC has not shown that its earnings would have been sufficiently harmed when the ARO was established.

As to the assertion of retroactive ratemaking, the fundamental purpose of creating a deferral is to recognize that the costs were not being recovered in rates when incurred. Moreover, the test period in this case is the 12 months ending December 31, 2016 adjusted for known and measurable charges through December 31, 2017. Consequently, many of the costs are within the test period as adjusted. As to the 2015 costs, the Commission determines they along with subsequently incurred costs have been properly deferred for recovery in this case, were extraordinary when incurred, and were not being recovered in rates in effect at the time incurred. DEC notified the Commission of its decision to establish the ARO in December 2015 and sought permission to defer in December 2016. The AGO commented on the DEC request and did not object to the timing of the request.

The Commission customarily requires contemporaneous approval of deferral accounting for extraordinary expenditures incurred between general rate cases. The Commission prefers this procedure over efforts to recover pre-test year costs recovery in the general rate case where no contemporaneous approval had been sought. This is not a case where DEC failed to seek contemporaneous approval. DEC sought deferral in 2016 after giving earlier notification in 2015. It was in 2016 that the Company had information permitting a quantification of the costs at issue. Just as a utility cannot request prior approval of extraordinary storm damage costs before the storm occurs, no requirement exists of pre-event approval of CCR costs such as these - only reasonably contemporaneous approval, and the Commission has waived even this requirement in the past. See Order Granting General Rate Increase, (Dec. 21, 2012), Docket No. E-22 Sub 479, addressing DNCP's request for deferral of costs of the Bear Garden generating plant. Significantly, any AGO complaint as to timing of the deferral request should have been raised at the time DEC sought approval of the deferral. The AGO made no such complaint.

Similarly the AGO's argument that the deferral should be disallowed because DEC's earnings in 2015 and 2016 were such that deferral was unjustified should have been made at the time the deferral was sought. Moreover, the AGO's untimely evidence to support its theory of lack of economic harm to justify deferral is deficient. The AGO has referred to surveillance reports showing what DEC was earning in 2015 and 2016. These are returns that do not reflect the CCR remediation costs. DEC's December 21, 2015 notification of ARO accounting and its surveillance reports expressly state that the ARO costs are not reflected. Without showing what the returns would have been without deferral, the surveillance report returns tell little about the financial justification for the deferral. Moreover, 2016 is a test year. Financial data fully adjusted after general rate case changes should be used if looking backward at what DEC's earnings were in 2016. The Commission determines that the CCR remediation in the ARO were properly deferred and that the costs so deferred are appropriately amortized over five years and that the unamortized portion is eligible for a return.

6. The Public Staff's Specific Cost Disallowance Proposals

The Commission must undertake a detailed analysis before any costs can be disallowed on the basis of findings of imprudence. 1988 DEP Rate Order, p. 15. The Public Staff undertook such an analysis of the Company's coal ash costs, and based on that analysis presented three discrete and specific proposed sets of disallowances. Two were presented through witness Junis: first, $2,109,406 of legal expenses associated with the defense of litigation matters regarding alleged environmental violations and, second, $2,352,429 reflecting groundwater extraction and treatment costs that witness Junis asserted exceed what CAMA would have required absent alleged environmental violations. Finally, Public Staff witnesses Garrett and Moore recommended a disallowance totaling $97,698,274 relating to the cost of the Company's compliance activities at Buck, Dan River, Riverbend, and W.S. Lee, on the grounds that those activities were more costly than other reasonable alternatives.

a. Junis: Alleged Environmental "Violations"

The Public Staff, through witness Junis, asserts that disallowance of the Company's litigation expense and groundwater costs is justified because these costs flow from "violations" of the law. Tr. Vol. 26, pp. 728-34. For the reasons discussed below, the Commission based on its assessment of the evidence and in the exercise of its discretion determines not to authorize the Public Staff's proposed disallowances of legal expense and groundwater extraction and treatment costs. The evidence does not support a finding that DEC violated the law (with the exception of the federal plea agreement, the costs related to which are not at issue here), nor does it support a finding of imprudence with respect to these costs.

i. Junis: Legal Expenses

Witness Junis cites the Glendale Water case (State ex rel. Utils. Comm'n v. Public Staff, 317 N.C. 26, 343 S.E.2d 898 (1986)) for the proposition that the legal expense should be excluded. In that case, the North Carolina Supreme Court held that legal expense associated with a penalty proceeding in which the utility had been found to have violated the law should be excluded. Witness Junis suggests that the same rationale would apply to his exclusion of the Company's litigation expense related to what he terms DEC's failure to comply with environmental laws and regulations. He claims that "compelling evidence" of such violations is shown by the SOCs and DEQ reports of exceedances. Tr. Vol. 26, pp. 728-29.

The distinction between this case and Glendale Water is that, with the exception of the federal plea agreement with respect to the Dan River spill and Riverbend (for which the Company is not seeking to recover any costs of penalties and fines), there is no finding in the other litigation brought against the Company, or admission by the Company in that litigation, that any "violation" actually occurred. No Intervenor introduced evidence in this case that any "violation" actually occurred. Witness Junis' testimony that the Company's legal expenses for state litigation of coal ash complaints resulted from "violations" is based on the DEQ reports of groundwater exceedances and the fact that DEC sought SOCs to address seeps at the Allen, Marshall, and Rogers (Cliffside) stations, both of which Junis interprets as "compelling evidence of DEC's violations." Tr. Vol. 26, pp. 730-31.

The Commission determines that the facts of this case are distinguishable from Glendale Water. Litigants settle disputed matters frequently for many reasons that are unrelated to the settling parties' underlying view of the merits of the dispute. In this case, for example, the Company and the Public Staff have entered into a Partial Settlement which includes a rate of return on equity of 9.9% (versus the Public Staff's recommendation of 9.1%), and a capital structure of 52% equity and 48% debt (versus the Public Staff's recommendation of 50/50). This settlement, which the Commission has approved, therefore results in millions of dollars paid by customers over and above the Public Staff's pre-settlement position, but that does not mean that the Public Staff somehow ceased to believe in that pre-settlement position. It means that the Public Staff, on balance, determines that its constituency (the using and consuming public) is better off with the Partial Settlement than without, despite the fact that the rate of return on equity and capital structure provisions of the settlement will cause increased rates. Likewise, an SOC is a regulatory mechanism intended to provide clarity and certainty with respect to scope and schedule for compliance-related activities given a change in circumstances, such as a change in requirements or in operations. The Company's willingness to enter into an SOC, therefore, is not premised upon an underlying admission of culpability. Furthermore, as explained by witness Wells, a DEQ report of an exceedance does not equate to a violation of environmental law or regulation.

Witness Junis has attempted to expand the applicability of Glendale Water by applying its holding beyond a litigated finding of liability to include (1) resolutions of complaints that do not involve any finding of liability and (2) pending legal claims of environmental violations, where there is "compelling evidence of environmental violations." Tr. Vol. 26, pp. 729-30. The Commission disagrees with the Public Staff position. Glendale Water applies where there is a finding of liability and the Commission declines to extend its holding further. In addition, the Commission does not find DEQ exceedance reports or SOCs to constitute compelling evidence of environmental violations.

The Commission determines, as it did in the 2018 DEP Rate Order, that entering into a settlement does not equate to an admission of guilt or wrongdoing. 2018 DEP Rate Order, p. 180. Conflating the existence of a settlement agreement or an SOC with an admission or other proof of guilt or wrongdoing is inconsistent with both the law and public policy of North Carolina. The North Carolina Rules of Evidence, for example, prohibit parties from using the existence of a settlement as evidence of liability.[1] Likewise, in other matters before the Commission, the Public Staff has defended the regulatory policy of encouraging reasonable and prudent settlements. In 2016, NC WARN filed a Petition for Rulemaking seeking to require settlements between the Public Staff and utilities to be made open to the public. Tr. Vol. 12, p. 156-34; see also Order

[1] N.C. R. Evid. 408 ("Evidence of (1) furnishing or offering or promising to furnish, or (2) accepting or offering or promising to accept, a valuable consideration in compromising or attempting to compromise a claim which was disputed as to either validity or amount, is not admissible to prove liability for or invalidity of the claim or its amount. Evidence of conduct or evidence of statements made in compromise negotiations is likewise not admissible.").

Declining to Adopt Proposed Settlement Rules, Docket No. M-100, Sub 145 (Mar. 1, 2017) (Settlements Order). The Public Staff opposed NC WARN's petition, arguing that public policy favors settlements:

> [T]he Public Staff submits that settlements promote the informal exchange of ideas and information among the parties, the elimination of insignificant or noncontroversial issues ahead of an evidentiary hearing, informed decision making and the efficient administration of justice, especially in the complex matters that are typically before the Commission. Moreover, settlements result in savings to consumers by reducing litigation expenses that would otherwise be recoverable by utilities as a component of the cost of providing utility service.

Tr. Vol. 12, p. 156-35. See also Settlements Order, p. 3.

Further, in its opposition to NC WARN's petition, the Public Staff cited to North Carolina case law "touting the benefits of settlements" in business litigation. Tr. Vol. 12, p. 156-35. See also Settlements Order, p. 3 (citing Knight Pub. Co., Inc. v. Chase Manhattan Bank, N.A., 131 N.C. App. 257, 262, 506 S.E.2d 728, 731 (1998) (Knight)). The Public Staff relied on the principle articulated in Knight that North Carolina "law favors the avoidance of litigation," and a compromise made in good faith "will be sustained as not only based upon sufficient consideration but upon the highest consideration of public policy as well." Tr. Vol. 12, p. 156-35 (quoting Knight, 131 N.C. App. at 262, 506 S.E.2d at 731 (emphasis added) (internal quotations omitted)). As in the 2018 DEP Rate Order, the Commission again determines not to approve a disincentive to settle pending or future lawsuits. 2018 DEP Rate Order, p. 180. The Commission therefore rejects the Public Staff's proposed disallowance of the Company's legal.

ii. Junis: Groundwater Treatment Costs

Similar considerations apply to the groundwater extraction and treatment costs witness Junis seeks to disallow, which he characterizes as costs to remedy environmental violations that exceed what CAMA would have required absent such violations. He cites as examples of such costs those resulting from (1) the DEQ Settlement Agreement (also referred to as the Sutton Settlement), which Junis contends result in costs greater than would have been necessary to pay for CAMA compliance without violations, and (2) resolutions of lawsuits alleging environmental violations where the outcome involves remedial action that costs more than the risk classification warrants, and "compelling evidence" shows the outcome resulted from environmental violations. Tr. Vol. 26, pp. 731-32. Witness Junis applies this theory of disallowance to include the Company's expenditures for groundwater extraction and treatment at Belews Creek, made pursuant to the September 2015 Sutton Settlement between DEQ, DEC, and DEP. See Junis Exhibit 29, Official Exhibits Vol. 26 (DEQ Settlement Agreement). He also applies this theory to include the Company's expenditures for selenium removal equipment at the Riverbend plant. Tr. Vol. 26, pp. 733-34.

Consistent with the 2018 DEP Rate Order, the Commission again declines to find that the DEQ Settlement Agreement evidences violation of environmental obligations. The DEQ Settlement Agreement references in its recitals a DEQ "Policy for Compliance Evaluations" promulgated in 2011, and it appears from the recitals and their description of that Policy that there was a very serious question as to whether any violation of the State's groundwater standards had occurred. See DEQ Settlement Agreement, at 3, 4-5. The recitals also indicate, with the passage of CAMA, that the Company would be required to close its coal ash basins, and that CAMA "dictate[d], in detail a procedure for assessing, monitoring and where appropriate remediating groundwater quality in areas around coal ash impoundments in North Carolina ...." Id. at 3-4. Further, in the recitals the DEQ acknowledged that the CAMA requirements were "designed to address, and will address, the assessment and corrective action" associated with alleged groundwater contamination. Because CAMA would require the Company to implement certain actions, the Commission determines as it did in the 2018 DEP Rate Order (see 2018 DEP Rate Order, p. 181) that it was reasonable for the parties to settle irrespective of whether the Company had committed violations of 2L Standards. Had the Company continued to litigate the matter in this circumstance, its actions may have been deemed by the Public Staff and this Commission to be imprudent, with a disallowance of the legal costs incurred in connection with continued litigation.

The Commission finds the testimony of Company witnesses Wells and Kerin to be instructive with respect to the Public Staff's proposed disallowance of groundwater treatment costs, and entitled to substantial weight. Witness Wells' testimony demonstrates that DEC has in most instances adequately managed its coal ash and that the Company's management and appropriate responses to seeps and groundwater issues do not equate to environmental violations. Witness Kerin's testimony demonstrates that costs related to groundwater extraction and treatment at Belews Creek and its purchase of wastewater treatment equipment at Riverbend were reasonable and prudent and are recoverable.

Witness Wells testified that exceedances of groundwater standards and the existence of seeps in the vicinity of the Company's ash basins do not indicate mismanagement or poor compliance programs. He explained that the existence of groundwater exceedances at or beyond the compliance boundaries at DEC sites is rather a function of where these sites are on the timeline of groundwater assessment and corrective action under modern laws that have changed the way unlined basins are viewed. He testified further that the Company's decision to use unlined basins to treat ash transport water was reasonable and consistent with the approach consistently employed across the power industry at the time that the basins were built, and noted that each DEC site had been properly and legally operating an unlined basin for at least a decade before the adoption of any regulatory requirements related to groundwater corrective action. He stated that as requirements changed over time, DEC has taken action required by DEQ's groundwater rules, and later by CAMA and the federal CCR Rule, to address groundwater impacts as they have been identified. As he noted, witness Junis did not contend that either DEC or the state of North Carolina was an outlier by using unlined basins during this timeframe, and no such contention could reasonably be made given well-published facts about coal power generation practices at that time. Tr. Vol. 24, pp. 227-29, 233, 236, 258.

Witness Wells adequately rebutted the Public Staff's suggestion that DEC only engaged in comprehensive groundwater monitoring and remediation when forced to do so by CAMA and other developments. He testified that the Company began monitoring groundwater at Allen in 1978, Belews Creek and Marshall in 1989, Dan River and W.S. Lee Steam Stations in 1993, and the remaining sites in or around 2006. He noted that, in 2011, DEQ prescribed a process to be undertaken by DEQ and utilities upon the identification of a groundwater exceedance near a coal ash pond, which included performance of an assessment to determine the cause of the exceedance and, as necessary, develop a Corrective Action Plan consistent with North Carolina groundwater rules. He stated that under that process, only after a utility failed to undertake corrective action when directed to do so would DEQ consider pursuing enforcement. He noted that, in contravention of witness Junis' testimony, all of this activity predates the threat of litigation by environmental groups, the DEQ enforcement suit, the Dan River spill, and CAMA. He also testified that, as witness Junis' testimony and exhibits demonstrate, DEC has always promptly responded to any concerns raised by the relevant regulatory entities and where necessary, implemented appropriate corrective action steps to remedy any issue. He stated that the Company has proactively sought consent orders and written agreements to ensure alignment with the regulatory agency as to appropriate scope and timing of additional investigation and corrective action. Tr. Vol. 24, pp. 230-31, 234-36, 259-60.

Witness Wells also disagreed with the Public Staff's suggestion that any exceedance or violation of water quality regulations, no matter how minor or how long ago, leads to the denial of cost recovery for any activity that acts to "cure" the impacts of the violation. In addition to reiterating that not all exceedances of the 2L standards amount to a violation that requires corrective action under the 2L rules, witness Wells stated that even when an exceedance requires corrective action, the groundwater rules do not treat the exceedance the same way as, for example, the Clean Water Act treats an exceedance of an NPDES permit limit. When the latter is violated, he explained, the permittee is immediately subject to an NOV and penalty, and must ensure the next discharge complies with the permit limit or risks a new NOV and escalating penalty. Tr. Vol. 24, pp. 244-45.

Witness Wells contrasted this process with groundwater standards, under which an exceedance does not immediately result in an NOV and escalating penalty. Instead, he explained the owner/operator must report the exceedance and work with the DEQ to determine whether it was due to permitted activity, assess the extent of the exceedance, and undertake corrective action. Any newly measured exceedances do not require a further site assessment and do not result in additional or escalating penalties, but are actually expected as an additional assessment prior to corrective action is conducted. He testified that the 2L rules' corrective action provisions are deliberately designed around the idea that older facilities, built before liners were a regulatory obligation, were likely to have associated groundwater impacts, that such impacts were not the result of regulatory noncompliance, and that they should be addressed in a measured process. He concluded that compliance with this process is not mismanagement and should not be held against DEC with respect to cost recovery. Tr. Vol. 24, pp. 245-46. The Commission agrees.

The Commission is further persuaded by witness Wells' testimony that witness Junis' characterization of groundwater violations under the 2L rules ignores the iterative nature of comprehensive site assessment. He noted that measuring exceedances at different locations in a plume around an activity may result in multiple exceedances of groundwater standards, but that does not result in multiple violations of the 2L rule's prohibition. He explained that this distinction is important for evaluating the claim that the number of exceedances indicates a "breadth of environmental violations." It would be more accurate to say, he explained, that, at seven sites, DEC has lawfully operated ash basins that, after decades of use, resulted in exceedances of groundwater standards at those sites. He pointed out how Duke Energy's coal ash basins are some of the most studied sites in North Carolina, with more than 1,400 groundwater monitoring wells, and that the number of exceedances presented by witness Junis signifies therefore the thoroughness of the evaluation rather than a number of groundwater violations. Tr. Vol. 24, pp. 238-41, 260-61. The Commission notes in particular witness Wells' testimony at the hearing that the iterative (and difficult) nature of monitoring groundwater impacts is illustrated by the fact that two wells located a short distance from each other could present very different conditions, including different naturally occurring constituents. Tr. Vol. 26, pp. 91-93.

Witness Wells also persuasively argued that the groundwater extraction and treatment costs that witness Junis recommended for disallowance relate to activity that DEC agreed to undertake pursuant to the DEQ Settlement Agreement to accelerate, but that would have been required in the normal course as part of the groundwater correct action under the CCR Rule and CAMA. Tr. Vol. 24, p. 241. Although CAMA borrows heavily from the 2L Rules, including by incorporating the substance of its corrective action requirements, one key difference between the two laws is that CAMA's groundwater assessment and corrective action provisions are triggered by exceedances – not violations – of the 2L groundwater standards.[1] In other words, unlike the 2L Rules, CAMA requires utilities to perform groundwater assessment and corrective action for all identified exceedances of the 2L groundwater standards regardless of whether the exceedance amounts to a violation of the applicable groundwater standard.

The Commission is also persuaded by the evidence presented by Company witness Kerin in response to the Public Staff's position, which shows that the groundwater treatment wells installed at Belews Creek would have been installed even without the DEQ Settlement Agreement, because while the time frame for that installation was moved up pursuant to the Agreement, the Company would have installed the wells in order to comply with CAMA even absent the Agreement. Tr. Vol. 24, p. 117.

Based on the credible and persuasive testimony of the Company's witnesses, the Commission determines, with exceptions addressed below, that there is insufficient evidence that DEC would have had to engage in any groundwater extraction and treatment activities absent the obligations imposed upon it by CAMA and/or the CCR Rule. Witness Wells' testimony in particular shows that the assertion that DEC's "violations" resulted in the DEQ Settlement Agreement and in groundwater extraction and treatment costs that would not otherwise have been incurred is incorrect and not supported by the evidence.

The Commission determines that Witness Kerin also successfully rebutted witness Junis' position that the cost of equipment to remove selenium at Riverbend should be disallowed. He explained that it was imperative for the Company to have a system to appropriately treat the site wastewater and to meet future permit selenium limits. He also noted that while this system is important for those reasons, because it is also expensive to operate, the Company will only use it when other physical and chemical extraction methods are insufficient. He emphasized the

[1] Id.; see also N.C. Gen. Stat. § 130A-309.211. When preparing a corrective action plan, CAMA does not require the utility to describe any 2L violation and instead required only a "description of all exceedances of the groundwater quality standards, including any exceedances that the owner asserts are the result of natural background conditions." N.C. Gen. Stat. § 130A-309.211(b)(1)a (emphasis added).

prudency of having this system in place should it be needed, in order to avoid the need to cease ash removal operations if selenium levels increased and no bioreactor was on site. He noted that such a delay would cost the Company millions of dollars of delay charges. Tr. Vol. 24, pp. 90, 117-19, 132. The Commission agrees that it was reasonable and prudent for the Company to purchase the bioreactor system to mitigate against potential violations of permit limits and declines to accept witness Junis' recommended disallowance of these costs.

No party disputes the reasonableness of the amount of groundwater assessment and treatment costs the Company seeks to recover in rates. The dispute relates instead to the fact that the groundwater assessment and treatment costs were incurred pursuant to a settlement with DEQ and in response to DEQ reports. The testimony of witnesses Kerin and Wells demonstrates that these costs – amounting to $2,352,429 – were reasonably and prudently incurred to comply with the Company's obligations under CAMA and the CCR Rule. The Commission determines that they therefore are recoverable in rates, as are the $2,109,406 in legal fees that witness Junis also proposed excluding.

The AGO, Sierra Club, and other Intervenors make similar arguments to the Public Staff that DEC has failed to keep pace with industry standards and should therefore not be allowed to recover current environmental compliance costs in rates. As in the DEP case, these Intervenors argue that the Company should have done more, in contradiction to other witnesses that DEC should have done less, than just comply with the current environmental regulations at the time.

As an initial matter, based upon the evidence presented in this case, with the exception of the federal criminal case to which DEC pled guilty, the Company has not been found liable for violations of the law. As stated above, the Commission will not use settlement agreements to find liability. The AGO witness asserts that the Commission should consider all of the seeps located at DEC's ash basin sites and deny recovery of CCR costs except – as clarified at the hearing – those which are incurred to comply with the CCR Rule. However, as stated in the criminal case that covered engineered seeps, DEQ and DEC have been in long-standing negotiations as to whether seeps are a violation of the law and since 2014, whether seeps should be covered by the NPDES permit. AG-Kerin Direct Cross Examination Exhibit 6, pp. 78, 95; AG-Kerin Direct Cross Examination Exhibit 5, p. 44. According to statements made in the criminal case, DEQ has currently not made a determination on this issue. AG-Kerin Direct Cross Examination Exhibit 5, p. 44.

In addition, the Commission finds the testimony of Company witness Kerin informative as to Intervenors' claims. Witness Kerin explained that the securities filings cited by AGO witness Wittliff simply notified the SEC of potentially significant coal ash costs that Duke Energy anticipated at that time, and potential new regulatory contingencies to which it could become subject; they were not intended to analyze the Company's coal ash management practices and do not support any claim that such practices were out of step with industry, much less that DEC was aware of any such inconsistency. Witness Kerin also rebutted the AGO's assertion that the Company should have built new lined impoundments rather than expand existing unlined impoundments, citing the significant expense that new lined impoundments would entail, while not eliminating the obligation to maintain existing unlined impoundments. He pointed out that such action would have put the Company at risk of disallowance of costs. He recalled witness

Wittliff's testimony in the DEP proceeding that utilities continued to use unlined wet ash impoundments because the law continued to allow them to do so, and noted the inconsistency between admitting that such a practice was legal and asserting that it was also imprudent. Witness Kerin also enumerated the ways in which the Company has practiced dam safety and explained that the five-year dam safety inspections demonstrate careful monitoring of issues as well as a lack of any major issue threatening dam integrity. Tr. Vol. 24, pp. 119-24. For many of the same reasons, witness Kerin demonstrated the inaccuracy of Sierra Club witness Quarles' assertions regarding the consistency of the Company's coal ash management practices with industry standards and the costs of lined landfills as opposed to surface impoundments. Tr. Vol. 24, p. 91.

The limitations of the Intervenors' and the Public Staff's approach is the fact that the kinds of actions they appear to have favored – such as lining ash ponds when others in the industry were not lining them, or creating dry ash basins when the Company's industry peers were sluicing coal ash into wet basin impoundments, would (a) have increased costs that would have been charged to customers, or (b) would have left the Company open to credible claims of "gold-plating," and therefore cost disallowance, which would have prevented the Company from moving forward with these suggested improvements in the first place. These parties advance inconsistent positions. They fault the Company for not undertaking steps that others were not, but at the same time disavow any responsibility of paying for that which they – in 20/20 hindsight – wish the Company had undertaken. As noted at the hearing during questioning of Company witness Wells, these parties criticize the Company's coal ash management practices dating back decades, yet took no actions themselves to address coal ash until within the past five years. For all of these reasons and based on the evidence presented, the Commission is not persuaded, with exceptions noted below and later in this the order, that any past violations by DEC, or many of its past coal ash management practices, support the discrete amounts of cost disallowances advocated by the Intervenors and the Public Staff in this case.

The AGO and the Sierra Club further assert that all of the coal ash closure costs are the result of unlawful discharges and are not recoverable pursuant to N.C. Gen. Stat. § 62-133.13. The Commission rejects the AGO and Sierra Club's reading of N.C. Gen. Stat. § 133.13. The costs being incurred are not resulting from an unlawful discharge as defined by the statute, which is a discharge that results in a violation of State or federal surface water quality standards. Rather, DEC is incurring the costs to comply with the federal CCR rule and CAMA.

Lastly, with respect to the bottled water expense DEC is seeking cost recovery of, although no party requested a specific disallowance for the cost of bottled water, the Commission finds that DEC shall remove from its request for recovery any costs for bottled water.[1]

b. <u>Garrett and Moore: Overview</u>

The Public Staff, through witnesses Garrett and Moore, asserts that the Company acted imprudently and unreasonably with respect to the management of CCRs from the Buck, Dan River, Riverbend, and W.S. Lee Plants, and contends that the Company should have selected different

[1] The total amount spent on bottled water through the end of August 2017 is $1,606,185. These costs include the bottled water itself, the delivery company and personnel associated with the delivery, and the consulting firm that is managing the overall bottled water delivery program for Duke Energy. Tr. Vol. 14, pp. 220-21.

management approaches, thereby saving costs. The Public Staff recommends that a $10,612,592 disallowance be applied with regard to Buck Plant ash (Tr. Vol. 21, p. 61), a $59,320,890 disallowance be applied with regard to the Dan River Plant ash (Tr. Vol. 21, p. 67), a $489,600 disallowance be applied to Riverbend Plant ash (Tr. Vol. 21, p. 74), and that a $27,275,192 disallowance be applied with regard to W.S. Lee ash (Tr. Vol. 21, pp. 34-34), for a total recommended disallowance of $97,698,274.

The Commission determines not to accept this discrete disallowance, based upon the testimony of Company witness Kerin, which the Commission credits and to which the Commission attaches substantial weight. In the 1988 DEP Rate Order, this Commission stressed the importance of carefully examining the Company's explanations of the decisions it made, as of the time they were made, and emphasized the credibility of the decision-makers, particularly in juxtaposition to after-the-fact analyses presented by Intervenor-retained consultants. See, e.g., 1988 DEP Rate Order, p. 29. The Commission does not question the bona fides or expertise of Garrett and Moore. The Commission is persuaded, however, by witness Kerin's testimony that Garrett and Moore missed or overlooked pertinent facts and real world conditions in their recommendations, and that their discrete disallowances are therefore unwarranted. Witness Kerin's testimony regarding the Company's decisions is entitled to substantial weight – more weight than after the fact evaluations from Garrett and Moore. Witnesses Garrett and Moore's recommended disallowances were challenged at the hearing through cross-examination. These witnesses were unable effectively to support their positions while on the witness stand. The Commission determines their recommendations deficient on the basis of a lack of credibility. In this regard, the Commission is not persuaded to discount witness Kerin's testimony by witness Wittliff's challenges to witness Kerin's expertise. As concluded in the 2018 DEP Rate Order, witness Kerin has "lived" this project since its inception (2018 DEP Rate Order, p. 187), and demonstrated competent understanding of the subject in pre-filed testimony and at the hearing. Witness Witliff's testimony from the witness stand likewise suffered from a lack of credibility.

i. Moore: Location of On-Site Landfill at Dan River

Witness Moore asserted that, while he agreed with DEC's decision to construct an on-site landfill at Dan River, he disagreed with the Company's chosen location for the onsite landfill. Tr. Vol. 21, pp. 90-91. Instead of locating the landfill within the footprint of the Ash Fill areas – which required first excavating and transporting off-site ash from those area – witness Moore contended that DEC should have considered locating the landfill along the western property boundary of the site, Id. at 91-92, even though he conceded that the CAMA moratorium prohibited construction of new or expanded CCR landfills located wholly or partly on top of the Primary Ash Basin, Secondary Ash Basin, and the Ash Fill 1 and 2 areas. Tr. Vol. 24, p. 94. Witness Kerin's rebuttal testimony demonstrates that witness Moore's proposal was not feasible in the time frames available to the Company, and in likelihood impossible from an engineering perspective.

Witness Moore illustrated his proposed landfill site location with a chalk-line, ovaloid drawn on top of an existing jurisdiction water designation map for the Dan River Plant. Tr. Vol. 21, p. 44; Moore Direct Exhibit 4. This drawing is the totality of the engineering work papers and documentation offered in support of his proposal in his direct testimony. Tr. Vol. 21, p. 92. To agree with witness Moore's recommended disallowance, the Commission would have to conclude that DEC should and could have constructed his proposed landfill in compliance with

North Carolina law. The Commission cannot reach that conclusion based on the dearth of supporting documentation from witness Moore regarding his proposed landfill, as well as the volume of evidence presented by witness Kerin in opposition to witness Moore's suggestion. An alternative proposed action must have been feasible in order to be a valid alternative. 1988 DEP Rate Order, p. 15.

Witness Moore admitted that he did not conduct a site suitability study for his proposed landfill location, nor did he conduct a hydrogeologic study of the conditions at the western portion of the Dan River Plant property. Both studies are required under North Carolina law before a landfill can be permitted or constructed. See 15A N.C. Admin. Code 13B §§ .0503-.0504. He did not analyze soil borings of that area of the property, did not visit the portion of the property where he proposed siting the landfill, despite having the opportunity to do so when he made a site visit to the property, and did not make an attempt, at the time he submitted his direct testimony, to calculate the height of his proposed landfill. Tr. Vol. 21, pp. 92-93. Witness Moore only did this after witness Kerin filed his testimony. Tr. Vol. 22, p. 26. His testimony and workpapers, or lack thereof, would not satisfy North Carolina's landfill permit application requirements, let alone justify construction of his landfill.

The Commission concludes that DEC engineers reached the reasonable and prudent decision to reject the western portion of the property as a feasible location for an onsite landfill. As witness Kerin discussed in his rebuttal testimony, there are many engineering and other obstacles to the construction of an onsite landfill along that portion of the property.

First, construction of witness Moore's proposed landfill would have required excavation of an LCID Landfill containing asbestos. The fact that the LCID Landfill contained asbestos was not known to witness Moore when he filed his testimony, but could have been discovered had he pulled the publicly available permit for that landfill. Tr. Vol. 21, pp. 97-99. In his direct testimony, witness Moore suggested that the LCID Landfill could have been excavated and transported to the Rockingham County Landfill. As the Rockingham County Landfill no longer accepts asbestos, witness Moore conceded that his proposal with regard to the LCID Landfill was no longer possible. Tr. Vol. 21, p. 99. Even if there was a location that could accept the materials containing asbestos in the LCID Landfill, the Commission is persuaded by witness Kerin's testimony that it was prudent for the Company to avoid unnecessarily exposing workers or neighbors to asbestos by locating the onsite landfill in a location that would have required excavation of the asbestos. Tr. Vol. 24, pp. 97-98.

Witness Moore's proposal was also infeasible in that it would have significant wetland and stream impacts as compared to the minimal impacts to streams and wetlands posed by the Company's chosen onsite landfill location. Witness Moore's testimony gave too little attention to stream and wetland impacts, suggesting that mitigation of on-site streams is not uncommon to allow for construction of landfills. Tr. Vol. 21, p. 65. However, witness Moore made no attempt in his testimony to identify the stream and wetland impacts, to prepare a permitting timeline for those impacts, or to analyze the likelihood that those impacts could be permitted. As witness Kerin stated in his rebuttal testimony, and witness Moore acknowledged during live testimony, the U.S. Army Corps of Engineers (Army Corps) will conduct an alternatives analysis demonstrating the practicality of other options that would not impact streams or wetlands, and that permit applicants are required to avoid and minimize aquatic resource impacts to the maximum extent practicable. Tr. Vol. 21, pp. 104-05; DEC-Garrett and Moore Cross Ex. 1, Tab 6; Tr. Vol. 24, pp. 98-100. As compared to witness Moore's proposal, the Company's selected landfill location avoided and minimized impacts to onsite streams and wetlands. Therefore, permitting witness Moore's selected location for stream and wetland impacts would have been challenging based on the Army Corps' alternative analysis criteria. In order to meet CAMA's deadlines, it was reasonable and prudent for DEC to avoid the permitting uncertainty created by witness Moore's proposal by avoiding impacts altogether.

Witness Moore's proposal raises additional permitting uncertainties. Witness Kerin testified that the stream combination on the western and southern sides of witness Moore's proposed landfill would have required the Company to obtain a new construction permit to construct an industrial NPDES outfall through the service water pond, and that both the permit and the outfall would have required substantial time to obtain and construct. Both the new permit and outfall would have to be in place before construction on the landfill could begin, potentially jeopardizing compliance with CAMA's deadlines. The CAMA deadlines provide the overarching framework by which prudency must be assessed. 2018 DEP Rate Order, p. 185. In addition, witness Kerin noted that the 100-year flood plain in this area intrudes into portions of witness Moore's proposed location, and would present additional permitting challenges and likely not leave sufficient space for required stormwater management features on the site. Tr. Vol. 24, pp. 100-02. Witness Moore did not dispute these conclusions.

The evidence shows that had witness Moore visited the site of his proposed landfill, he would have confronted dramatic elevation changes and other topographical features, such as steep slopes, that would have made his proposed site difficult. Further, had witness Moore conducted a site suitability or hydrogeologic study, he would have discovered that the depth to bedrock on the western portion of the property is fairly shallow, leaving little room for excavation for fill volume, borrowing soil or buffering to groundwater. While witness Moore agreed that a landfill owner should minimize potential impacts to neighbors, wetlands, and dangerous materials as much as possible, (Tr. Vol. 21, p. 108), the above site-specific conditions unique to the western property boundary, which witness Moore did not consider in his analysis, would have resulted in a landfill that was in the neighbors' line of sight and more intrusive than the Company's selected location. Tr. Vol. 24, pp. 100-02.

DEC's decision to minimize impacts to neighboring properties in siting its onsite landfill was consistent with an agreement that the Company would ultimately reach with the City of Eden regarding the Dan River site. As a condition of allowing DEC to construct an onsite landfill, the City of Eden required that the landfill be located near the existing basins, and as remote from residential areas as feasible. Tr. Vol. 21, p. 106; DEC-Garrett and Moore Cross Ex. 1, Tab 7. Witness Moore did not dispute the City of Eden agreement's conditions. Tr. Vol. 21, p. 107-08. The nearest location to the existing basins is within the footprint of the former ash stack, and this is the location DEC chose for the landfill. This choice also minimized impacts to surrounding properties by ensuring that the landfill was located as far as feasibly possible from neighboring properties. In contrast, as witness Moore acknowledged, his selected location was not closest to existing basins or as remote as feasible from residential areas. Id. Therefore, had DEC selected witness Moore's proposed landfill location, Mr. Kerin testified, the City of Eden likely would not have approved the zoning required to construct the landfill in this location. See 15A N.C. Admin. Code 13B § .0504(1)(e) (requiring local government approval for construction of a landfill). Witness Kerin stated that, if witness Moore had considered the City of Eden agreement, he could not have concluded that his alternative landfill location was reasonable or prudent. Tr. Vol. 24, pp. 95-96. The Commission agrees.

Infeasible options do not support a finding of imprudence. 1988 DEP Rate Order, p. 15. Witness Kerin's testimony demonstrates that the Company's actions and real-time decisions regarding the Dan River site were in fact reasonable and prudent, and the costs were prudently incurred. The Commission therefore rejects the Public Staff's proposed disallowance of these costs.

ii. Moore: Buck as Beneficiation Site

Witness Moore contended that DEC should have chosen Weatherspoon over Buck as a beneficiation site, and recommended disallowance of beneficiation costs of $10,612,592 incurred within the test period at Buck. The Commission rejects witness Moore's discrete recommendation. Witness Kerin's testimony shows that witness Moore's analysis is based on a faulty interpretation of CAMA, and that DEC's selection of Buck was reasonable and prudent because it satisfies market demands and maximizes capital investment in the required beneficiation equipment.

CAMA requires the Company to: (i) identify two sites by January 1, 2017 and an additional site by July 1, 2017; and (ii) "enter into a binding agreement for the installation and operation of an ash beneficiation project at each site capable of annually processing 300,000 tons of ash to specifications appropriate for cementitious products, with all ash processed to be removed from the impoundments located at the sites." N.C. Gen. Stat. § 130A-309-216 (emphasis added). Witness Kerin testified that DEC satisfied CAMA's requirements by identifying Buck, H.F. Lee, and Cape Fear as the three beneficiation sites based on its conclusion that they offered the most feasible alternative and the best economic value to customers while complying with CAMA. Tr. Vol. 24, pp. 93, 105-08, 131.

At each of the three sites, the Company has contracted to install and operate STAR technology units to process the onsite ash. Tr. Vol. 21, p. 112. The Company has also contracted to sell 230,000 tons of ash from Weatherspoon as aggregate in the manufacture of cement. Id. at 59, 116; Tr. Vol. 24, p. 107.

Witness Moore suggests that the Company could have selected Weatherspoon as a beneficiation site if it had only found a buyer for another 70,000 tons of ash from this location to qualify under CAMA. By selecting Buck, witness Moore contended, Duke Energy supplied an additional 300,000 tons per year of CCR material to the concrete industry, in turn reducing the demand for the 70,000 tons per year of CCR material for the same purposes from Weatherspoon for which Duke Energy was unable to find a purchaser. While the Company agrees that reuse of ash at Weatherspoon is appropriate – and the Company is selling Weatherspoon ash for reuse today – it contends that the Weatherspoon ash would not satisfy CAMA. Based on the testimony of witness Kerin, the Commission agrees.

Contrary to Public Staff witness Moore's suggestions otherwise (Tr. Vol. 21, pp. 111-12), the Commission concludes that the most reasonable reading of N.C. Gen. Stat. § 130A-309-216 indicates that the General Assembly intended that Duke Energy install and operate technology, such as carbon burn-out plants and STAR technology, to process and transform ash to a usable product rather than use the basic drying and screening methods occurring at Weatherspoon. Tr. Vol. 24, pp. 106-07. It is here where witness Moore's theory becomes problematic.

Witness Moore's testimony suggested that the Company's handling of Weatherspoon ash, which does not involve beneficiation processing or much of any processing beyond excavation, would satisfy the CAMA beneficiation requirement. At the hearing, however, witness Moore admitted that the DEP sites chosen for beneficiation under CAMA – Cape Fear and H.F. Lee – and the DEC site, Buck, have and will use the STAR technology to beneficiate ash, and that the ash being sold from the Company's Weatherspoon site is not being beneficiated with STAR technology. He confirmed that installation of a STAR facility to convert ash for cementitious purposes is a reasonable and prudent method of executing the requirements of CAMA, and that ash from the ponds is run through the STAR unit and burned to lower the carbon content of the ash. The process changes the physical and chemical characteristics of the ash, thereby creating a stronger product that can be used in the ready-mix market. Tr. Vol. 21, pp. 111-13, 115; DEC-Garrett and Moore Cross Ex. 1, Tab 12, p. 6. As witness Moore agreed on cross examination, the Weatherspoon ash and the ash that is beneficiated with such technology, as at Buck, are "apples and oranges." Id. at 117.

Witness Moore did not object to Duke Energy's beneficiation approach at H.F. Lee and Cape Fear. Having concluded that installing STAR units at H.F. Lee and Cape Fear was a reasonable and prudent "method of executing the requirements of CAMA," (Id. at 113), the Commission determines that he cannot creditably argue that Duke Energy could have simply excavated, dried, and sold ash from Weatherspoon and still satisfied CAMA's beneficial reuse requirements. Id. at 112. In other words, witness Moore admitted that STAR units accomplish the following: "the installation and operation of an ash beneficiation project at each site capable of annually processing 300,000 tons of ash to specifications appropriate for cementitious products." N.C. Gen. Stat. § 130A-309-216. His recommended disallowance, however, in this rate case, depends on a reading of CAMA that does not require installation of a STAR unit or similar technology. The Commission determines that the Public Staff position is inconsistent. The Commission concludes that CAMA contemplates the installation of STAR units or other ash processing technology that changes the physical and chemical characteristics of ash to specifications appropriate for cementitious products.

In addition, witness Kerin pointed out that, even after issuing an RFP, Duke Energy has only been able to secure a buyer willing to enter into a long-term contract for 230,000 tons of ash from Weatherspoon, but not the additional 70,000 tons. Tr. Vol. 24, pp. 105-06. Witness Moore made no attempt to identify a potential buyer for the 70,000 tons. Tr. Vol. 21, pp. 118-19. While the Weatherspoon ash is sold under contract to cement manufacturers and is used as raw material or aggregate in the manufacture of cement, the processed ash from Buck is used as a replacement for cement in concrete. Because these are separate products that are used for different purposes, the sale of beneficiated ash from Buck has no impact on the demand for ash from Weatherspoon. Id. at 105-06. The Commission determines that finding a buyer for 70,000 tons of ash from Weatherspoon would not solve the compliance problem witness Moore identifies. Under his proposal, none of the ash would be processed through a STAR Unit or similar technology, and would therefore not meet CAMA's beneficiation requirement.

The Commission also agrees with the Company that, because CAMA requires the installation of a STAR Unit or similar technology, a cost of approximately $181 million, it was reasonable for the Company to consider the amount of ash available at the site and the potential uses for the ash when making a decision to invest in beneficiation at a particular location. Weatherspoon contains only 2.4 million tons of ash, which is approximately one-third the 6.4 million tons at Buck, so the per-ton cost to process ash at Buck is significantly lower than it would be at Weatherspoon. Additionally, Weatherspoon is in a poor geographic location in relation to the major markets for ash used in the cement industry. Because trucking the ash is part of the cost of the sales, Buck's proximity to Charlotte and Greensboro makes it a much better location for beneficiation, and has the highest revenue projection, followed by Cape Fear (Greensboro and Raleigh) and H.F. Lee (eastern North Carolina and Virginia).

Witness Moore's proposal is not feasible as it would not satisfy the Company's statutory requirement to beneficiate ash. Alternative proposed actions must be feasible in order to truly be alternatives. 1988 DEP Rate Order, p. 15. The Commission cannot, therefore, conclude that the Company was unreasonable or imprudent by selecting Buck over Weatherspoon, and by implementing a beneficiation plan at Buck that does satisfy CAMA.

iii. Moore: Riverbend Off-site Transportation Costs

Public Staff Witness Moore took no exception to DEC's overall ash management plan at Riverbend, including its decision to remove CCR material from the ash stack area or the cinder pit, even though those units are not subject to CAMA or CCR. He did object to DEC's decision to transport and dispose of CCR material from the ash stack to the R&B landfill in Homer, Georgia and to the Brickhaven Facility. Witness Moore recommended that the Commission disallow $489,000 as the premium that was paid to dispose of CCR material from the Ash Stack at the R&B Landfill in Homer, Georgia versus the Marshall Station. Tr. Vol. 21, pp. 72-73.

As witness Kerin noted in his testimony, DEC was required to begin excavation of ash from Riverbend within 60 days of receiving its stormwater permit from DEQ. When DEC received that permit in May 2015, Marshall was not available to accept Riverbend ash. Since DEQ issued the permit on May 15, 2015, DEC had until July 15, 2015 to begin excavating Riverbend ash. While the Company was exploring long-term options to receive the Riverbend ash, it was still obligated to meet DEQ's deadline, and thus it was imperative that the Company contract with a company to haul and dispose of the Riverbend ash on a short turnaround. Waste Management National Services, Inc. (Waste Management) was able to meet that requirement, and began trucking ash from Riverbend on May 21, 2015, and transported the final load on September 18, 2015. While DEC eventually received approval to dispose of Riverbend ash at Marshall, the Commission is persuaded that DEC would not have been able to send ash to Marshall within the time frames required by DEQ. Tr. Vol. 21, pp. 93, 108-10, 131-32.

Witness Moore's recommended disallowance is based on a "perfect world" scenario where DEC could have accurately predicted permitting uncertainties, such as the dates when DEQ was going to issue the stormwater permit for Riverbend or approval for ash disposal at Marshall. The Commission declines to approve disallowances where the Company promptly achieved compliance with DEQ's 60-day excavation requirement. The Commission uses the CAMA deadlines as the framework by which to assess prudency. 2018 DEP Rate Order, p. 185. The Commission concurs with witness Moore that "[t]he lowest cost option may not always be the reasonable or prudent decision. The determination must be made on a case-by-case basis and the specific factors, obligations, site-specific limitations and other factors known by management at the time." Tr. Vol. 21, pp. 89-90. The Commission concludes that the Company acted reasonably and prudently for the Company to begin excavation at Riverbend as soon as practicable in order to ensure compliance with DEQ's requirements. This decision necessitated finding a temporary disposal solution; therefore, the costs associated with that temporary disposal solution are also reasonable and prudent and should not be disallowed.

iv. Garrett: W.S. Lee Off-site Transportation Costs

The Commission is not persuaded by witness Garrett's testimony that a lower cost option at W.S. Lee was feasible. Like witness Moore's recommended onsite landfill at Dan River, witness Garrett's proposal for W.S. Lee may look viable on paper, but when applied to "real world" conditions, it loses its persuasiveness.

As an initial matter, the Commission agrees with the Company and witness Garrett that DEC's overall ash management plan at W.S. Lee, which includes building an onsite landfill to store ash from the Primary and Secondary ash basins, is reasonable and prudent. Tr. Vol. 21, pp. 25-26. The Commission also agrees that some action was necessary to excavate the IAB or Old Ash Fill to mitigate risk associated with the long-term environmental issues, based on the proximity of the IAB to the Saluda River. The Commission declines to accept, however, witness Garrett's conclusion that delaying excavation of those sites for seven years would have been acceptable to South Carolina regulators or would have eliminated the risk to the Saluda River. Tr. Vol. 24, p. 156.

No dispute exists that DEC's decision to excavate the IAB and Old Ash Fill before the onsite landfill was complete eliminated the geotechnical and environmental risks by November 2017. Tr. Vol. 21, p. 28. Under witness Garrett's plan, ash in the IAB and in the Old Ash Fill would have been left in place and not excavated until the on-site landfill in the secondary ash basin was complete in 2022. Tr. Vol. 21, pp. 129, 130-31. Therefore, the ash would have remained in the IAB and Old Ash Fill an additional seven years until 2022 as compared to the excavation plan DEC undertook. Tr. Vol. 21, pp. 127, 131-32. Under the Company's agreement with SCDHEC, which required excavation of the IAB and Old Ash Fill by December 31, 2017, witness Garrett's seven-year delay was not an option. Tr. Vol. 24, p. 151.

Even assuming witness Garrett's plan was technically feasible and would have resolved the stability issues, implementing his plan would have required trading old risks for new risks. See DEC-Garrett and Moore Cross Ex. 1, Tab 20. Witness Garrett acknowledged during live testimony that the report contained at Tab 20 concluded that if the IAB ash was not removed, danger arose of it's flowing into the Saluda River. Tr. Vol. 21, pp. 135-36. He also acknowledged that in certain areas of the IAB that abut the Saluda River, the steep, 1:1 slopes are covered in trees and vegetation. Id. at 137. Witness Garrett also agreed that trees would have to be removed to execute his proposal, but he did not consider in his analysis how the trees would be removed (with heavy equipment or chain saws) or how tree removal might affect slope stability. Id. at 148-49. He also acknowledged that soft, alluvial clays run beneath the IAB and the steep slopes where his proposed work would occur, and that the dam itself is partially constructed from ash and sandy silt that would also have to be excavated. Id. at 138, 141. Witness Garrett conceded that his work proposal as reflected in Garrett Direct Exhibit 3 is "not a design document" nor is it "specific instruction on how to go about that work." Id. at 141. He also acknowledged the limitations of the S&ME report on which he relies, in that it, too, does not explain practically how a slope stability and grading project would be executed. Id. at 141, 146-47.

The Company provided persuasive evidence in the form of witness Kerin's testimony that witness Garrett's proposed grading and stability project would not have been reasonable or prudent. Witness Kerin testified that the equipment necessary to implement witness Garrett's proposal could not have safely traversed the dike on the downslope of the IAB. Moving the heavy equipment to the downstream/river side of the downslope to excavate silt, ash, sand and trees would have created undue risk to bank stability, worker safety, and risk of an ash release into the Saluda River. Witness Garrett's proposed project would have unnecessarily put worker and environmental safety at risk, and the delay would have been unacceptable to DEC and to the SCDHEC. These new risks were understandably unacceptable to the Company. Tr. Vol. 24, pp. 112-14, 132.

The Commission cannot conclude that witness Garrett's proposal was the more reasonable and prudent option because the Public Staff cannot show, from an engineering perspective, how the work would be practically and safely executed. The Public Staff only presented a concept. To take witness Garrett's plan from concept to reality would require engineering and design plans with specific instructions on how the work would be conducted. Tr. Vol. 21, p. 141. The Public Staff, although armed with an engineering expert, failed to present any such plans. On the other hand, Company witness Kerin credibly provided evidence of the real-world flaws with witness Garrett's concept, from both timing and engineering perspectives.

The Commission concludes that it was reasonable and prudent for Duke Energy to immediately excavate the IAB and Old Ash Fill, in compliance with its agreement with SCDHEC. Duke Energy was able to eliminate existing risks without creating new risks. The Commission declines to second-guess the Company's judgment in that regard. Therefore, because no onsite landfill was available for the disposal of the IAB and Old Ash Fill materials at the time they were excavated, it was also reasonable and prudent for the Company to utilize the R&B landfill in Homer, Georgia for disposal of those materials, and the costs associated with that effort should not be disallowed.

Finally, based on witness Kerin's testimony the Commission agrees that the Company's plan to mitigate future risk of operating two ash management structures, which would be the result if it did not excavate the Structural Fill Area at W.S. Lee in the future, is reasonable and prudent, even though witness Garrett did not suggest any disallowances with respect to this plan. Witness Kerin stated that, in order to resolve the concerns of SCDHEC and environmental groups, the Company agreed to mitigate future risk of operating two ash management structures by managing all ash at W.S. Lee through a single management structure – the landfill – as opposed to taking a piecemeal approach as suggested by witness Garrett. He stated that if the Company was later required to excavate the Structural Fill area after the landfill project was completed, it would incur greater costs than it will incur by managing the ash while the landfill project is ongoing, and that the decision to excavate this area now is reasonable and prudent approach to mitigating against potential future ash related liability and to reduce future costs for the site. Tr. Vol. 24, pp. 93, 116.

7. Conclusion with respect to January 1, 2015 – December 31, 2017 Costs

The Commission finds that the costs are known and measurable, were reasonably and prudently incurred, and to the extent capital in nature are used and useful in the provision of service to customers. The Commission determines the costs were properly deferred. As such, with the exception noted below, they are recoverable from customers. The issue that remains is the amortization period over which this recovery is to be made.

The Commission deems the Company's proposal, which submits that the amortization period should be five years, to be reasonable and appropriate. The Public Staff, in its 51/49 "equitable sharing" proposal, suggests a period of 25 years (with no return), but its suggestion is tied to (indeed, mathematically required by) the sharing arrangement. As discussed more fully above, the Commission determines that the Public Staff's sharing proposal is from the Commission's perspective arbitrary and unfairly punitive and therefore unacceptable. Thus, a 25-year, no return amortization period is not approved. The five-year period suggested by the Company is identical to the period over which the Commission approved in the 2018 DEP Rate Case, as well as the period over which Dominion North Carolina Power's already-incurred coal ash basin closure costs were amortized in the 2016 DNCP Rate Case (Docket No. E-22, Sub 532). Further, inasmuch as the Company appropriately applied ARO accounting and this Commission's deferral orders issued in Docket No. E-7, Sub 723 to these costs, the Company is eligible to earn a return.

In summary, with the exception noted below, DEC has shown by the greater weight of the evidence that its coal ash basin closure costs actually incurred over the period from January 1, 2015 through December 31, 2017 are (a) known and measurable, (b) reasonable and prudent, and (c) where capital in nature used and useful, and, as such, those costs are recoverable in rates. DEC has further shown that its proposal that these costs be amortized over five years, with a modified return on the unamortized balance, is reasonable. The Commission encourages the selection of minority and women-owned businesses, where appropriate, when contracting for future services associated with compliance with CAMA and the CCR Rule.

8. The Commission's Cost of Service Penalty

The costs DEC has incurred through the end of the test year as adjusted in coal ash remediation tasks have been substantial, and the Company will continue on an annual basis to incur a substantial level of costs through approximately 2028. The vast majority of these costs would have been incurred irrespective of management inefficiency in order to comply with EPA CCR requirements. When DEC initially constructed coal ash impoundments and transported CCRs to them many decades ago, it did so in accord with the prevailing industry practices at the time, especially in this part of the country. In part and over time this was in response to environmental regulations requiring the removal of pollutants such as CCRs from the coal plant smokestacks to reduce air pollution.

Over time, the EPA and other environmental regulators have scrutinized the impact of CCRs in unlined repositories on surface and ground water and have assessed the extent to which harmful constituents in CCRs exceed those naturally occurring in the environment and their impact on human health. One long-lasting debate before EPA addressed the extent to which CCRs should be classified as hazardous waste under RCRA, a debate only recently resolved. Had EPA classified CCRs as a hazardous waste, economic reuse in all likelihood would have become an impossibility.

Another area of scrutiny has been the appropriate need for and method of remediation with respect to closing and potentially moving CCRs from unlined impoundments.

Many of the criticisms of DEC's CCR remediation practices raised in this case, before the federal district court in the criminal proceeding and before other courts and administrative agencies, address issues such as seeps from impoundment dikes, improper maintenance of dikes, lax reporting, exceedances and NPDES violations with respect to surface water discharges. The primary and ultimate remediation however is dewatering and excavation of and transportation from existing unlined impoundments and construction of new lined impoundments or, for older discontinued impoundments that qualify, caps preventing rainwater intrusion. This is where the vast majority of the billions of dollars of CCR remediation costs must be spent. This ultimate remediation step is necessary to prevent most of the leachate from infiltrating groundwater from the bottom of unlined basins, but would have been required irrespective of the harms that constitute other alleged mismanagement. In addition, this remediation process cures other less pervasive environmental and health threats.

Intervenors fault DEC for failure to undertake this remediation process years earlier before being required to do so. The evidence shows that DEC undertook steps toward CCR remediation and incurred costs in anticipation of impending closure but hesitated to spend substantial sums until the requirements became clearer. Had DEC acted in compliance with assertions that it act more aggressively sooner, it would have incurred costs its consumers would have been responsible for then. So from a ratemaking perspective, this Commission's concern, the question of when the remediation should have taken place, now or in the future or twenty years ago, is not determinative of whether the costs of the remediation should be recovered through rates and to what extent. Intervenors are unable to show when DEC should have acted differently in the past or what the increased costs would have been then. The Commission rejects efforts from any source to advance theories in support of discrete disallowances that parties before the Commission have not seen and have therefore been denied any opportunity to analyze and respond. The Commission must depend on parties before it, particularly the Pubic Staff, with the statutory responsibility to audit and respond to general rate case filings to advance theories for cost recovery.

Indeed, whenever undertaken, the costs would have been site specific, and establishing a past cost in this case would be a near impossibility. As DEC would have been required to undertake the remediation at issue in 2015 through 2017, irrespective of other improper actions of which it has been accused and for which it pled guilty to and was sentenced for in the criminal proceeding, any disallowance in this case must be made within the context of these facts. Had DEC acted irresponsibly in neglecting seeps earlier, the remedy would have been pumping the water from the seeps back into the basin, for example. Costs of this remediation would have been negligible in comparison to removing ash or cap-in-place.

DEC in the past contemplated a future requirement to close unlined impoundments. While it was reasonable and appropriate to anticipate and plan for what EPA's ultimate decisions would be, the Commission determines not to penalize DEC through denial of cost recovery for its decision to wait until EPA's CCR determinations in this area were finalized. Had DEC acted prematurely in anticipation of regulations under consideration but not yet implemented, with the expenditure of substantial sums in the process, and with the ultimate EPA decisions differing from those anticipated, DEC risked unjustified expenditures. In 2015, the EPA announced the Clean Power Plan. Had electric utilities incurred costs prematurely to comply, these costs could have been called into question when the U.S. Supreme Court stayed the Clean Power Plan. Even today efforts to soften the impact of the EPA CCR Rule are under consideration by the current administration. If effectuated, anticipated cost recovery may change in the future.

A significant example of the ambiguity and uncertainty DEC faced in the management of CCR impoundments is illustrated by reference to a November 1, 2004 Long Term Ash Strategy Study Phase Report addressing 1983 and 1984 CCR repositories at DEP's Sutton coal fired plant in New Hanover County referred to in the 2018 DEP order. The 1983 impoundment was unlined and had reached capacity prior to the 2004 report. The 1984 impoundment was lined and was rapidly approaching capacity, and the report identified and classified alternatives for CCR use or disposal to prevent shutdown of the Sutton plant. In the "Problem Description" section of the report, the authoring engineer listed issues either directly or indirectly related to a contribution to the overall ash strategy for the Sutton plant. The issues were described as secondary and not a dictating factor in the solution of the best alternative but as a look at overall environmental structure and stewardship. The first issue addressed the 1983 unlined impoundment that for the most part had ceased to receive CCRs.

> <u>1983 Pond is Unlined</u>
>
> The first issue is that the 1983 ash pond was constructed during a period when it was not required to provide a non-permeable liner, and was constructed with the native sandy soils.[1] This pond has been functionally full since 1983, but is still permitted[2], and is occasionally used when there are issues requiring the 1984 ash pond to be temporarily dry. The current environmental atmosphere is that these ponds will eventually have to [sic] emptied and placed in a lined containment to eliminate the leaching of the ash products into the groundwater system. This is an issue that is not currently being pressed, but it is anticipated that with the tighter environmental conditions it will soon become an emergent issue. This issue is

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[1] The reference to "native sandy soils" is significant. Its characterization for absorption of leachates is greater than for the clay soils of the Piedmont at issue with respect to the DEC impoundments in this case.

[2] The 1983 impoundment operated pursuant to a DEQ permit. Obviously, at the date of the report, DEQ was not requiring closure or dewatering and removal of the CCRs. This would not occur until passage of the CCR Rule and CAMA years later.

> aggravated by the fact that a test monitoring well located 300' from [sic] edge of the 1983 ash pond has shown high levels of arsenic during the past two quarterly tests. This may or may not be related to the unlined ash pond. A recent study by an independent firm indicated this concern may be less than originally thought. It could be mitigated by adding monitoring wells to the NPDES permit, but could still pose an issue in the future.[1] There is also a county well water source approximately 1200' from the test well that is monitored by the county.
>
> Elsewhere in the report under the "Do Nothing" alternative, the author stated:
>
> It is assumed that the North Carolina Division of Water Quality (NCDWQ) will require the 1983 ash pond to be emptied and lined to comply with current ash pond regulations. For the purpose of this study it is estimated that there is a 5% chance annually of the ash pond required to be relined starting 2007, and that in 2013 there will be a 10% chance annually thereafter until 2019.

In 2018, it is less than clear as to what the author refers to as the "current environmental atmosphere" or "current ash pond regulations." The author of the report does not elaborate or explain. Were the Commission to attempt to read the author's mind, this would be mere speculation. To the extent DEQ was enforcing them, DEQ was not requiring DEC to take additional steps to comply. As the report states, the 1983 impoundment was operating pursuant to a DEQ permit, and DEQ had not required closure. The author repeatedly uses the word "assumes" and "anticipated" to predict the environmental regulators' future intent. The author's speculation as to if and when unlined impoundments might have to be dewatered and excavated was off the mark. With respect to the 1983 Sutton unlined impoundment, that impoundment will never be relined. If it had been relined as the author suggests, the Company would have been required to move the CCR's twice, once to some new location, then back to the newly relined 1983 repository. Such is not the case for compliance with EPA CCR rules and CAMA where the CCR's were moved only once -- deposited in a new, lined landfill.[2]

The EPA's CCR rule was passed in 2015, and the NC CAMA was passed in 2014 with deadlines a number of years beyond that. DEC did not choose the alternative recommendation in the report, creation of an industrial park, nor did it excavate the unlined 1983 impoundment in response to the report. The report contains no recommendation to excavate the 1983 impoundment solely for environmental remediation. The Commission is unable today to say how in the past the 1983 impoundment would have been excavated and how the excavated CCRs would be placed in a lined impoundment, what the cost would have been and what cost recovery treatment would have

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[1] This recitation is consistent with the comprehensive testimony of witness Wells in this case that with respect to the types of contaminants at issue from CCR impoundments, they exist in naturally occurring quantities in the soil. Monitoring wells showing exceedances above standards are not dispositive without measurement of naturally occurring constituents.

[2] Intervenors are highly critical of DEC for failure to take action in response to consultants, in-house investigative teams and outside research entities such as EPRI before 2015. However, quite inconsistently, when it comes to criticizing DEC's actions after 2015, they assert that DEC was remiss in not stopping short of what SCDHEC wished for remediation of W.S. Lee and the consultant for the selenium treatment at Riverbend. They contend DEC spent too much in complying with these required or suggested remediation steps.

been appropriate. Indeed, the 1983 impoundment today is being excavated pursuant to express EPA and DEQ guidelines, and the parties to the DEP case vigorously contest how compliance with these requirements should be accomplished and what the cost should be.

The purpose of the report was to determine the best course based upon the fact that the 1984 lined ash pond was reaching capacity and would be non-operational by June 2006. It is important to note that the author was indicating that the 1984 ash pond would be non-operational under the NPDES permit due to capacity constraints as opposed to environmental concerns.

Intervenors are advocating substantial disallowances in this case for expenditures DEC incurred to meet CAMA deadlines, such as at Dan River, Riverbend, or Buck, before all of the regulatory requirements had been finalized. A substantial area of contention is exceedances and environmental violations addressing harmful constituents in coal ash even though determinations with respect to naturally occurring levels of background concentrations of these constituents have not been established. Rules for regulating seeps from dikes are yet to be finalized. As testified to by witness Wells, with respect to covered engineered seeps, DEQ and DEC have been in long-standing negotiations as to whether seeps are a violation of the law and since 2014 whether seeps should be covered by the NPDES permit. Even as DEC continues to remediate, state regulatory agencies must review and approve the process and may impose additional restrictions, limitations and requirements. Even subsequent to EPA CCR rules and CAMA, the General Assembly enacted the Mountain Energy Act of 2015, changing the requirements for the Asheville plant remediation for DEP. Closure options for each of the CCR impoundments are site specific. Even now, Intervenors criticize the selection of repositories for beneficiation. Intervenors contend DEC spent too much to comply with CAMA. As discussed below, others advocate that this Commission supersede the authority of environmental regulators and require excavation of all DEC's impoundments and prohibit cap-in-place and spend more than DEC contemplates irrespective of what DEQ may require. The Commission is unable to recreate the past and place a price tag on remediation costs that might have been incurred in anticipation of environmental requirements.

Intervenors maintain that DEC should have addressed CCR remediation in years prior to EPA's CCR regulations and CAMA when the industry began to grow concerned over potential CCR environmental degradation. Under this theory, remediation costs would have been lower then and as a consequence CCR remediation costs DEC seeks for recovery beginning in 2015 are excessive and should be disallowed in whole or in part.

The most significant shortcoming in this theory is that no attempt has been made by any party to this case to demonstrate what the costs would have been in earlier years that theoretically would be so much lower as to make the 2015 and subsequent CCR remediation costs unnecessary or excessive. To the extent efforts are made in this case after the record has closed, as was the case in the DEP case, DEC has had no opportunity to respond and any such effort is unfair and inappropriate.

Before EPA CCR rules and CAMA, DEC's impoundments were operated under permits authorized and overseen by DEQ or its predecessor, clients of the AGO. DEQ suggested no requirements that DEQ dewater the impoundments, remove the CCRs and transport them to lined landfills or install caps in place. No requirements existed for DEC to follow. Had DEC undertaken impoundment closure, DEQ would have been required to oversee the process, but of what that oversight would have consisted is unknowable today.

DEC has incurred costs beginning in 2015 and thereafter pursuant to elaborate EPA and CAMA requirements under close scrutiny and oversight from DEQ. Parties to this case hotly contest and dispute the steps DEC has taken to comply and assert that DEC's expenditures have been unreasonable.

In an effort to comply with CAMA, DEC identified Buck as a beneficiation site. Public Staff witness Moore argues DEC should have chosen instead Weatherspoon and that DEC therefore spent $10,612,592 too much between January 1, 2015 and November 30, 2017.

In order to comply with CAMA, DEC constructed an onsite landfill of Dan River. Public Staff witness Moore argues that DEC selected the wrong site, the former footprint of the Ash Fill 1, and should not have increased the costs to transport CCR materials offsite. He contends that DEC spent $59,320,890 too much.

In order to comply with CAMA, DEC transported CCRs from the Riverbend Ash Stack to the R&B landfill in Homer, Georgia and to the Brickhaven facility. Public Staff witness Moore contends that the material should have been disposed of at the Marshall plant and DEC spent $489,600 too much.

In order to comply with SCDHEC requirements, DEC attempted to close the regulated ash basin of W.S. Lee and mitigate risks of the unregulated inactive ash basin and fill area. Public Staff witness Garrett disagreed with DEC's decision to immediately begin excavation and transportation from these basins and transport CCRs to the R&B landfill in Homer, Georgia. Witness Garrett testified that DEC spent $27,275,192 too much.

Public Staff witnesses contend that DEC spent $97,698,274 too much to comply with EPA and CAMA. Even with access to steps DEC took and to the compilation of costs DEC incurred, these witnesses encountered difficulty understanding what DEC did. Witness Moore calculated the cost for excavating, transporting and disposing of Ash Stack I at the Dan River off-site to be $83,531,985. This was $3.8 million too high because this amount should have been attributable to excavation and transportation of ash from the Primary Ash Basin. The cost to build the alternative landfill location when accounting for the need to address asbestos and relocate the warehouse building at Dan River increases witness Moore's cost determination by $10,790,900. Witness Moore originally included costs of parcels at Cliffside even though DEC had not requested recovery of those costs. Witness Moore assumed DEC began transport of CCRs from Riverbend to the R&B Landfill beginning May 2015 and continuing to February 2016. However, the DEC contract with Waste Management was for 17 weeks through September 18, 2015.

Witness Moore criticizes DEC for spending too much at Buck, Riverbend, and Dan River <u>to comply with</u> CAMA[1] requirements. Witness Junis criticizes DEC for spending too much at Belews Creek and Riverbend for remediation <u>not required by CAMA</u> for selenium removal. Witness Quarles criticizes DEC for <u>spending too little</u> at Allen and Marshall to remediate by not removing the coal ash from the unlined basins there in disregard of what DEQ may ultimately require for compliance with CAMA. The Commission deems the various Intervenor theories for remediation cost disallowance "all over the map" and deficiently inconsistent.

With so much disagreement over what DEC should have done or is doing to comply with EPA requirements and CAMA, the Commission determines that insurmountable obstacles exist to quantify the alleged offsets that are a fundamental element to Intervenors' disallowance theory. The Public Staff, the agency required by statute to audit rate requests and recommend adjustments, candidly testified that it does not base its recommended equitable sharing recommendations on past DEC imprudence. That agency was unwilling to attempt to speculate what DEC should have done in the past, when it should have acted and, most significantly, what the costs would have been. No other party has undertaken such effort. Without any evidence sponsored by any witness quantifying what DEC should have spent in the past, the Commission has no basis for disallowing 2015-2017 DEC remediation costs in support of a theory that DEC should have done more prior to 2015.

The Commission would be required to anticipate the difficulty in complying with local ordinances like the ordinance DEC confronted from the City of Danville. The Commission would be required to anticipate the level of community opposition such as that experienced at Riverbend. The Commission would be required to anticipate what, if any, issues the legislature or DEQ might have imposed for beneficiation. The Commission would be required to anticipate the reaction of state or local representatives to DEC's decision to excavate or cap-in-place repositories within their legislative districts. The Commission concludes such tasks are unwarranted.

Intervenor theory on groundwater exceedances is that DEC violates 2L standards whenever monitoring wells show exceedance of standards or where DEC has not installed monitoring wells in addition to those required by DEQ to disprove the existence of exceedances. Some of the exceedances were from measurements taken within the CCR impoundments. The Commission cannot accept this theory. The fallacy of the theory rests on the fact that the undisputed evidence is that all of the constituent elements measured against the standards, including iron, manganese and pH, constituents harmful neither to the environment nor human health, occur naturally in the North Carolina soils irrespective of the proximity of coal ash impoundments. The evidence shows that DEQ by its actions or inactions does not agree that the existence of exceedances without evidence that they are caused by coal ash contamination pose a risk to the environment or human health so as to require immediate remediation. DEQ has established a low priority to DEC's request to add 2L limits to NPDES permits. Although the Commission is not an environmental regulator, it must agree with DEC and DEQ that failure to take the costly actions required to comport with this Intervenor theory falls well short of mismanagement so as to justify some unquantified disallowance of 2015-2017 costs of dewatering and removal of CCRs from unlined pits or construct caps, which will cure exceedances caused by CCR groundwater contamination, if any.

This Commission's responsibility is cost recovery. Environmental regulators must oversee protection of the environment and public health. The Commission's responsibility is to determine whether coal ash remediation costs as required by environmental regulators should be recoverable through rates.

Another factor the Commission must address is the imposition of requirements of CAMA in addition to those of EPA. The evidence in this case is that the level of transportation and beneficiation costs being contested arises from more aggressive CAMA deadlines and uncertainty over the timing of the granting of regulatory permits for replacement impoundments. Except as addressed generically elsewhere, the Commission is reluctant to second-guess specific DEC decisions on its attempts to comply with these requirements in a 20/20 hindsight fashion. Likewise, the Commission is reluctant, except in limited fashion, to penalize DEC for good faith efforts to comply with state statutes irrespective of the factors motivating the General Assembly to impose them.

In his testimony, AGO witness Wittliff asserts that DEC's mismanagement caused CAMA and that costs DEC incurred to comply with CAMA in excess of those to comply with EPA CCR requirements should be disallowed. Witness Wittliff makes no effort to quantify the disallowance he proposes under this theory. In contradiction of its own witness, the AGO in its post-hearing brief argues that all of DEC's 205-2017 CCR remediation costs should be disallowed -- again without showing what DEC's costs should have been before 2015 under the AGO's theory. The AGO insists it is up to DEC to make these calculations for it.

Aside from the unsubstantiated theoretical underpinnings of the Wittliff argument, it is not possible to segregate CAMA 2015-2017 costs from EPA CCR costs. Indeed, a major prudency disallowance advocated by the Public Staff addresses 2015-2017 remediation costs at DEC's W.S. Lee plant in South Carolina. DEC was required to meet deadlines beyond those imposed by the EPA but not as a result of CAMA, which did not apply outside of North Carolina.

Conversely, the Commission is unable to find DEC faultless in the dilemma it has faced. Much testimony addresses the issue of whether DEC's mismanagement of CCRs "caused" the General Assembly to enact CAMA. DEC argues that other nearby states enacted CCR remediation statutes in addition to EPA's CCR rules, and that the Dan River spill affected the timing but not the substance of CAMA's requirements. The Commission is unable to conclude that DEC mismanagement is the primary cause of CAMA. Just as a preamble never accepted cannot legally justify legislative intent, neither can the absence from earlier versions of CAMA that would have addressed cost recovery. Nevertheless, the provisions of CAMA directly address remediation of DEC CCR repositories and impose accelerated deadlines with respect to them. The Commission therefore is unable to conclude that DEC mismanagement to which it admitted in the federal criminal court proceeding was not at least a contributing factor. Even DEC witness Wright's testimony suggests as much. While DEC presents persuasive evidence that its alleged mismanagement has not been supported and was not the cause of CAMA, this evidence is difficult to reconcile with its admissions and guilty pleas before the federal district court in the criminal proceeding. DEC represented that it mismanaged its CCR activities.

The Commission's conclusions with respect to the impact of DEC's mismanagement as a contributing factor to the enactment of CAMA are significant in two ways. First, the Commission determines that this conclusion adds support to the Commission's assessment of a management penalty in the form of cost disallowance arising primarily from the Company's admissions of mismanagement in the federal criminal case. Secondly, it supports the Commission's determination to reject more discrete disallowances such as those addressed by the Public Staff with respect to Buck, Riverbend and Dan River transportation costs. The Commission deems these costs traceable to CAMA timelines, implemented in part in response to DEC's CCR management practice, but is unpersuaded that the quantification of the costs is accurate or that the severity of the proposed disallowances is justified. Consequently, the Commission takes the incurrence of these costs into account in establishing the amount of its management penalty.

DEC admits to pervasive, system-wide shortcomings such as improper communication among those responsible for oversight of coal ash management. As stated above, while the Commission cannot state that CAMA would not have been passed or that its requirements other than accelerated deadlines would have been less onerous but for DEC's mismanagement of its CCR activities, neither can it state that DEC activities were without impact on the CAMA provisions that have resulted in increased costs that are at issue in this case. More fundamentally, in its admissions and pleas of guilty before the federal district court, DEC has outlined acts of criminal negligence through management misfeasance. In so doing, the Commission determines that, irrespective of CAMA, DEC has placed its consumers at risk of inadequate or unreasonably expensive service.

The Commission must regulate DEC pursuant to the requirements of Chapter 62 to see that compatibility with environmental well-being is maintained. N.C. Gen. Stat. § 62-2(a)(5). Service is to be provided on a well-planned and coordinated basis that is consistent with the level of energy needed for the protection of public health and safety for the promotion of the general welfare as expressed in the state energy policy, N.C. Gen. Stat. § 62-2(a)(6). All companies are prevented from violating environmental statutes. N.C. Gen. Stat. § 143-215.1. DEC is required to maintain safe and reliable service. As an electric utility, safety usually means safe electric service. In the context of this case, the Commission also determines that it means assuring safe operation of its coal-burning facilities so as not to render the environment unsafe. Declining to acquire and install a relatively inexpensive camera in a decades-old storm water drainage pipe over which the large coal ash impoundment is constructed when engineers repeatedly recommend such installation does not comply with a duty to provide safe service.

Fortunately, Dan River was a plant where coal-fired generation had been discontinued at the time of the 2014 spill. Risers in disrepair, inadequate oversight of impoundment dikes and seeps have not resulted in catastrophic failures causing plants to be taken offline or service disruptions, but DEC's irresponsible management of its impoundments over a discrete period of time placed its customers at risk of inadequate service and has resulted in cost increases greater than those necessary to adequately maintain and operate its facilities.

Consequently, having pled guilty to management criminal negligence, DEC cannot go without sanction in the form of cost of service disallowances. At the same time, to the extent the Dan River plant spill has contributed to the CCR remediation expense that otherwise would have been lower, the Company has borne responsibility for Dan River remediation costs without ratepayer support. The Company has been penalized by the federal district court. It cannot seek cost recovery of these monetary penalties or remediation assessments. Further, the mismanagement to which DEC pled guilty was only for a fraction of the time DEC operated the impoundments. No evidence was submitted that DEC's management was imprudent from the initial date of operation. The penalties imposed by this Commission take the form of denial of recovery of a return on historic remediation costs that reduce a portion of costs that ratepayers otherwise would have borne. The Commission deems double penalization inappropriate as an unwarranted penalty that has a tendency to unduly threaten the long-term overall wellbeing of the Company, a situation not in the best interest of its consumers.

A major difficulty the Commission confronts in this case is the identification and quantification of the appropriate CCR remediation adjustment to incurred costs. The record does not contain evidence appropriately quantifying the cost DEC incurred with respect to discrete remediation activities.[1] The Public Staff's witnesses' encountered difficulty in quantifying and supporting the costs for the alleged Cliffside, Riverbend and Dan River disallowances and other less specific ones motivates the Commission to resist imposition of discrete cost disallowances. The Commission deems disallowance of the totality of costs, as some parties advocate, unjustified. The Commission deems full recovery, as DEC advocates, unjustified. The Commission deems the Public Staff's 51/49 equitable sharing disallowance unfairly punitive and of questionable legal sustainability. The Commission deems requirements that more costs be imposed than DEQ might require without cost recovery unjustified. Moreover, the Commission deems it inadvisable to approve or suggest future disallowances with respect to CCR remediation expenditures as far away as 2028 and beyond. In sum, the Commission cannot agree with any of the parties in this case and must fashion and quantify a remedy different from any of those advocated before it.

The Commission operates under a legislative mandate that requires it to fix rates that will allow a utility "by sound management" to pay all of its reasonable operating costs, including maintenance, depreciation, and taxes, and earn a fair return on its investment. N.C. Gen. Stat. § 62-133(b)(4). State ex rel. Utils. Comm'n v. General Telephone Co., 285 N.C. 671, 208 S.E.2d 681 (1974). If the Commission finds that a utility has not been soundly managed, it may penalize a utility by authorizing less than a "fair return." Id.[2] The Commission must quantify the penalty by making a finding of what return would have been allowed if there were sound management. Id. The North Carolina Supreme Court has stated that "[t]he size of the penalty is left to the judgment of the commission, but must be based upon substantial evidence, and the penalty must not result in a confiscatory rate of return." Id. General Telephone addressed a rate of return on rate base penalty for mismanagement resulting in inadequate service. In this case, DEC's mismanagement takes the form of admitted inadequate oversight of its CCR activities that placed service to its consumers at risk and, at least indirectly, increased costs. As the penalty is a defined

[1] As the Commission recited in its order in the DEP case, AGO witness Wittliff was asked whether he offered any opinion on what he thought the Company's appropriate amount of recovery under the CCR rule should be. He responded:

> ... I would explain that I'd love to have been able to come up with some extremely precise numbers and explain it all to you where it all made crystal clear sense and you could hang your hat on it and that's the number, we can pin that down. The problem is, is that this is, as we've already - - everyone seems to have observed, is it's an extremely complex case with a lot of moving parts, and it's not as easy to - - to make that sort of definitive statement. Tr. Vol. 15, pp. 77-78.

The same evidentiary shortcoming is present in the record in this case.

[2] See also State ex rel. Utils. Comm'n v. Morgan, 277 N.C. 255, 177 S.E.2d 405 (1970) (holding "that it is not reasonable to construe [the statute] to require the Commission to shut its eyes to 'poor' and 'substandard' service resulting from a company's willful, or negligent, failure to maintain its properties [] and it is obvious that consistently poor service, attributable to defective or inadequate or poorly designed equipment or construction justifies a subtraction ...").

monetary penalty rather than a percentage return penalty, the impact on cost of service would be the same if it had been a rate of return on rate base penalty.

Consequently, the Commission in the exercise of its judgment and discretion, determines that a management penalty in the approximate sum of $70 million is appropriate with respect to DEC CCR remediation expenses accounted for in the earlier established ARO with respect to costs incurred through the end of the test year as adjusted. This penalty is based on the totality of evidence contained in the record, as recited in detail above, and does not result in confiscation. Had the Commission not imposed this penalty, the ARO costs would have been amortized over five years with a full authorized return on the unamortized balance. As the Commission has addressed comprehensively above in this order, the Commission possesses the discretion to authorize a return on the unamortized balance. The unamortized balance is not a recurring test year operating expense. The annual amortization of the balance (return of not return on) is the amount that equals to operating expense pursuant to N.C. Gen. Stat. § 62-133(b)(3). The penalty will be imposed by reducing the resulting annual revenue requirement by $14 million (from the return on the unamortized balance on the capitalized costs) for each of the five years, resulting in an approximate $70 million management penalty. While this penalty differs in form from that in General Telephone, the Commission determines that conceptually General Telephone provides appropriate precedent. By imposing this management penalty, the Commission does not suggest that further penalty or disallowances with respect to past DEC actions or inactions will be imposed with respect to future CCR remediation expenses. The size of the penalty meets judicial requirements as it is quantified and is not confiscatory.

With respect to CCR remediation costs to be incurred during the period rates approved in this case will be in effect, the Commission determines that the "run rate" or the "ongoing compliance costs" mechanism advocated by DEC will not be approved. By requesting the creation of an ARO, in addition to the run rate, DEC concedes that treating CCR expenditures as a recurring test year expense is inadequate. Future annual costs, the evidence shows, are predicted to vary substantially from year to year. Instead, CCR remediation costs incurred by DEC during the period rates approved in this case will be in effect shall be booked to an ARO that shall accrue carrying costs at the approved overall cost of capital approved in this case (the net of tax rate of return, net of associated accumulated deferred income taxes). The Commission will address the appropriate amortization period in DEC's next general rate case, and, unless future imprudence is established, will permit earning a full return on the unamortized balance. While this ratemaking treatment will, in limited fashion, diminish the quality of DEC's earnings, over time, assuming reasonable and prudent CCR management practices, it permits appropriate recovery. Prior to the next rate case, the Commission shall require that DEC provide a detailed accounting of its Cost of Removal Reserve for its steam assets and how the Company is utilizing this Cost of Removal Reserve.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 73

The evidence supporting this finding and conclusions is contained in the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, the Stipulation, and the entire record in this proceeding.

Public Staff witness Maness stated that coal ash costs prudently incurred from 2015 through 2017 (i.e., costs not subject to Public Staff recommended disallowances apart from equitable sharing) should be allowed provisional cost recovery. Tr. Vol. 22, pp. 63-64. He explained that the reasonableness of some of those costs may depend on the outcome of legal proceedings or other legal determinations, as described by witness Junis. Id. Witness Junis testified that environmental lawsuits had not been resolved for several DEC plants. Tr. Vol. 26, p. 732.

Witness Wright argued against witness Maness' recommendation of provisional cost recovery. Witness Wright stated that provisional rates appeared to be retroactive ratemaking and the utility should not be subject to hindsight review. Tr. Vol. 12, errata pp. 156-39-40.

Provisional cost recovery is appropriate in certain circumstances. However, the Commission is not persuaded that there is good cause to order provisional cost recovery of DEC's CCR costs that are approved in this Order. The Commission has weighed the Public Staff's and other intervenors' concerns about the pending insurance lawsuits and pending determinations by DEQ, EPA, and certain courts, that will establish whether past actions of DEC amount to environmental violations against the uncertainty that is inherent in provisional rates. With regard to the insurance litigation, DEC has committed that insurance proceeds recovered by DEC will benefit ratepayers as an off-set to DEC's CCR costs. Further, the insurance proceeds are not known and measurable as of the end of the test year. Moreover, the Commission has included in this Order specific reporting requirements and other conditions with which DEC must comply regarding the insurance proceeds.

With respect to pending determinations by EPA and DEQ, the Commission is not inclined to delay its work in order to wait for these agencies to complete their work. As a result, on balance the Commission finds and concludes that it will not order that the CCR cost recovery in this docket is provisional.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 74-75

The evidence supporting these findings and conclusions is contained in the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, the Stipulation, and the entire record in this proceeding.

DEC has used a demand allocation factor to allocate its costs related to its compliance with state and federal environmental regulations regarding coal ash pond closures in this case. Tr. Vol. 19, p. 39. Additionally, the Company has identified specific CAMA-related costs and allocated these costs directly to North Carolina customers. Tr. Vol. 6, p. 314.

Public Staff witness Maness recommended applying a jurisdictional allocation of all coal ash expenditures by a comprehensive system factor. Tr. Vol. 22, pp. 66-68. He stated that his adjustment removed the distinction between costs DEC described as CAMA-only and the remainder of the coal ash costs. Id. at 66. He stated that for CAMA-only costs, DEC utilized North Carolina retail allocation factors that do not allocate any of the system level costs to South Carolina retail operations. Id. at 67. He opined that even though some of the costs incurred by DEC are being incurred pursuant to North Carolina law, it is fair and reasonable to allocate those costs to the entire system because the coal plants associated with the costs are being, or were, operated to serve the entire DEC system. Id. Public Staff witness Maness also stated that he used the energy allocation factor to allocate system-level coal ash costs to North Carolina retail operations, rather than the demand-related production plant allocation factor utilized by the Company. Id. at 67-68. Witness Maness recommended that an energy allocator be used to determine the North Carolina retail portion of the coal ash costs because they are being incurred due to the fact that the coal ash was produced by the burning of coal to produce energy over the years, and like the cost of coal, should be allocated by energy, and not peak demand. Id. at 68.

NCSEA witness Barnes also objected to DEC's classification of coal ash costs as demand related. He argued that this approach is contrary to cost causation principles because coal ash is a by-product of consumption of a fuel, and the volume of coal ash produced is associated with overall energy use, not demand during a single hour of the year. He recommended that all coal ash remediation costs approved for recovery be allocated using an energy allocator. Tr. Vol. 20, p. 62.

Additionally, CIGFUR III witness Phillips testified in support of the Company's proposed allocation of coal ash management costs on a demand basis, stating that such allocation "is appropriate and should be approved." Tr. Vol. 26, p. 258. CIGFUR III witness Phillips further testified that coal ash is not a fuel, but an environmental waste with no energy potential. Id. at 271. Witness Phillips also stated that compliance costs associated with coal ash remediation did not exist at the time the coal was burned, but arose more recently. Id. Therefore, remediation costs should not be allocated on a kilowatt-hour basis. Id. Further, the investment associated with coal ash ponds is typically included in generation plant accounts and should be allocated on the same basis and DEC allocates generation plant based on demand. Id.

In her rebuttal testimony, DEC witness McManeus opposed witnesses Maness' recommendation that the costs DEC identified as "CAMA only" be allocated to all jurisdictions, instead of directly assigning these costs to North Carolina. Tr. Vol. 6, p. 313. Witness McManeus explained that while she generally agrees that the costs of a system should be borne by all of the users of the system, the Company has identified very specific cost categories that should be treated as an exception to this general rule due to their nature as being unique to North Carolina. Id. These cost categories include groundwater wells used specifically for CAMA purposes and permanent water supplies provided to North Carolina customers pursuant to CAMA. Tr. Vol. 14, p. 120. Witness McManeus explained that this allocation is consistent with prior Commission decisions related to the Company's costs of complying with other North Carolina laws including REPS and the North Carolina Clean Smokestacks rule. Tr. Vol. 6, pp. 313-14. Because the Commission has allowed the Company to recover 100% of its costs associated with complying with those North Carolina laws, the Company believes it is also appropriate that CAMA-specific costs be directly assigned to North Carolina customers. Id. at 314.

Additionally, Company witness Hager responded to witnesses Maness' and Barnes' recommendation to classify coal ash costs as demand related. Witness Hager explained that the costs in question are associated with compliance with federal and state environmental requirements related to closing coal ash ponds. Tr. Vol. 19, p. 39. Residual end of life costs typically and logically follow the cost of the plant, which is allocated based on demand. Id. This is supported by the fact that end of life costs (removal costs) and salvage values are factored into depreciation rates, and depreciation expenses are allocated based on demand. Id. Witness Hager also noted that it is also consistent with end-of-life nuclear fuel costs in nuclear decommissioning costs which are allocated based on demand. Id. at 39-40.

The Commission finds and concludes, with respect to the above-stated adjustments, that it is appropriate to (1) allocate the costs DEC has identified as "CAMA Only" costs by the comprehensive allocation factor, rather than a factor that does not allocate costs to the South Carolina retail; and (2) allocate all coal ash expenditures by the energy allocation factor, rather than the demand-related production plant allocation factor. Regarding the jurisdictional allocation, the Company had directly assigned costs for certain groundwater wells and permanent water supplies to North Carolina on the grounds that such costs were mandated by CAMA and were unique to North Carolina. Tr. Vol. 6, pp. 259, 313-14; Tr. Vol. 14, p. 134. In contrast, witness Maness argued the coal plants had served the entire North Carolina and South Carolina system of DEC, so the costs should be allocated across both jurisdictions. Tr. Vol. 22, pp. 66-67. Regarding the allocation factor, the Company recommended the demand-related factor (Tr. Vol. 6 p. 314; Tr. Vol. 19, pp 39-40), whereas the Public Staff argued for the energy-related factor because the amount of coal ash is related to the amount of energy produced. Tr. Vol. 22, pp. 67-68. The Commission agrees with Public Staff witness Maness that the amount of coal ash correlates with the amount of energy produced from coal, and that the entire DEC system benefited from that energy. Accordingly, and consistent with the Commission's February 23, 2018, Order in Docket No. E-2, Sub 1142, the Commission finds and concludes that the deferred coal ash costs should be allocated across the entire DEC system, and should be allocated on the energy-related factor.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 76-78

The evidence supporting these findings of fact and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

On February 26, 2018, the AGO filed a Stipulation as to Admission of Evidence. The AGO and DEC stipulated that the testimony given by Company witness David Fountain regarding insurance coverage in Docket No. E-2, Sub 1142 (DEP Rate Case), along with the associated exhibits, is appropriate to be admitted into evidence in the present case. The testimony was located in the DEP Rate Case in Volume 7 of the transcript in pages 368 through 505 and AGO Fountain Cross Examination Exhibits 1 through 8.

In its post hearing brief, the AGO requested that the Commission monitor the insurance litigation and contended that it would be appropriate for the Commission to make similar findings and conclusions regarding insurance that it made recently in the DEP Rate Order.

The Commission concludes that DEC should be required to place all insurance proceeds received or recovered by DEC in the Insurance Case in a regulatory liability account and hold such proceeds until the Commission enters an order directing DEC as to the appropriate disbursement of the proceeds. In addition, the regulatory liability account shall accrue a carrying charge at the overall rate of return authorized for DEC in this Order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 79

The evidence supporting these findings of fact and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

With regard to DEC's CCR costs from 2018 forward, DEC witness McManeus testified that DEC is requesting to establish a regulatory asset/liability account and defer to this account the portion in annual rates that is more than DEC's actual costs, or the amount in annual rates that is less than DEC's actual costs. In essence, the asset/liability account would be a tool used to true-up the difference in DEC's next general rate case.

The Commission agrees with DEC's recommended approach, not only for CCR costs, but also for all cost deferral accounts. A deferred cost is not the same as the other cost of service expenses recovered in the Company's non-fuel base rates. A deferred cost is an exception to the general principle that the Company's current cost of service expenses should be recovered as part of the Company's current revenues. When the Commission approves a typical cost of service, such as salaries and depreciation expense, there is a reasonable expectation that the expense will continue at essentially the same level until the Company's next general rate case, at which time it will be reset. On the other hand, when the Commission approves a deferred cost the Commission identifies a specific amount that has already been incurred by the Company, or, in the case of CCR costs, is estimated to be incurred by the Company. In addition, the Commission sets the recovery of the amount over a specific period of time. Further, the Company is directed to record the recovery of the specific amount in a regulatory asset account, rather than a general revenue account. If DEC continues to recover that deferred cost for a longer period of time than the amortization period approved by the Commission that does not mean that DEC is then entitled to convert those deferred costs into general revenue and record them in its general revenue accounts. Rather, the Company should continue to record all amounts recovered as deferred costs in the specific regulatory asset account established for those deferred costs until the Company's next general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 80-82

The evidence supporting these findings of fact and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

The Company presented Revised McManeus Stipulation Exhibit 1 – Updated for Post-Hearing Issues reflecting DEC's revised requested increase incorporating the provisions of the Stipulation, the Company's position on the unresolved issues and the impact of the EDIT decrement riders. Per those exhibits, the resulting proposed revenue requirement increase of the Company is $372,527,000. Boswell Corrected Third Supplemental and Stipulation Exhibit 1, Schedule 1 shows the Public Staff's revised recommended incorporating the provisions of the Stipulation, the impact of the EDIT decrement riders and its adjustments reflecting the Public Staff's position on the unresolved issues. The resulting proposed revenue requirement adjustment by the Public Staff is ($385,697,000).

As discussed in the body of this Order, the Commission approves the Stipulation in its entirety and makes its individual rulings on the unresolved issues as discussed. Due to the intricate and complex nature of some of the issues, the Commission requests that DEC recalculate the required annual revenue requirement as consistent with all of the Commission's findings and rulings herein within 10 days of the issuance of this Order. The Commission further orders that DEC work with the Public Staff to verify the accuracy of the recalculations. Once the Commission receives this filing, the Commission will work promptly to verify the calculations and will issue an Order with final revenue requirement numbers.

In addition, the Commission requests that DEC and the Public Staff provide the Commission with the demand and energy allocation factors that they, respectively, deem appropriate for allocating the CAMA costs to the North Carolina retail jurisdiction.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 83

The evidence supporting this finding of fact and conclusions is contained in the Company's verified Application, the testimony and exhibits of all the witnesses, the Stipulation, and the entire record in this proceeding.

Pursuant to N.C. Gen. Stat. § 62-133(a), the Commission is required to set rates that are "fair both to the public utilities and to the consumer." In order to strike this balance between the utility and its customers, the Commission must consider, among other factors, (1) the utility's reasonable and prudent cost of property used and useful in providing adequate, safe and reliable service to ratepayers, and (2) a rate of return on the utility's rate base that is both fair to ratepayers and provides an opportunity for the utility through sound management to attract sufficient capital to maintain its financial strength. See N.C. Gen. Stat. § 62-133(b). DEC's continued operation as a safe, adequate, and reliable source of electric service for its customers is vitally important to DEC's individual customers, as well as to the communities and businesses served by DEC. DEC presented credible and substantial evidence of its need for increased capital investment to, among other things, maintain and increase the reliability of its system and comply with environmental requirements.

Based on all of the evidence, the Commission finds and concludes that the revenue requirement, rate design and the rates that will result from this Order strike the appropriate balance between the interests of DEC's customers in receiving safe, reliable and efficient electric service at the lowest possible rates, and the interests of DEC in maintaining the Company's financial strength at a level that enables the Company to attract sufficient capital. As a result, the Commission concludes that the revenue requirement and the rates that will result from that revenue requirement established as a result of this Order are just and reasonable under the requirements of N.C. Gen. Stat. § 62-30, et seq.

IT IS, THEREFORE, ORDERED as follows:

1. That the Stipulation filed by DEC and the Public Staff on February 28, 2018, is hereby approved in its entirety.

2. That the Lighting Settlement entered into by DEC and NCLM, Concord, Kings Mountain, and Durham, is hereby approved in its entirety.

3. That DEC shall recalculate and file the annual revenue requirement with the Commission within 10 days of the issuance of this Order, consistent with the findings and conclusions of this Order and the Stipulation. The Company shall work with the Public Staff to verify the accuracy of the filing. DEC shall file schedules (North Carolina Retail Operations – Statement of Rate Base and Rate of Return, Statement of Operating Income, and Statement of Capitalization and Related Costs) summarizing the gross revenue and the rate of return that the Company should have the opportunity to achieve based on the Commission's findings and determinations in this proceeding. In addition, DEC and the Public Staff shall provide the Commission with the demand and energy allocation factors that they, respectively, deem appropriate for allocating the CAMA costs to the North Carolina retail jurisdiction.

4. That DEC is hereby authorized to adjust its rates and charges in accordance with the Stipulation and findings in this Order effective for service rendered on and after the following day after the Commission issues an Order accepting the calculations required by Ordering Paragraph No. 3.

5. That the Commission shall issue an Order approving the final revenue requirement numbers once received from DEC and verified by the Public Staff as soon as practicable.

6. That the appropriate revenue requirement for the first four years shall be reduced by the annual State EDIT rider decrement of $60,102,000.

7. That it is appropriate to recognize a $211,512,000 per year reduction in DEC's revenue requirement to reflect the current 21% Federal corporate income tax rate in DEC's base rates.

8. That DEC's proposed $200 million per year credit metric mitigation measure is denied.

9. That DEC shall continue to maintain all EDIT related to the Tax Act in a regulatory liability account for three years or until its next general rate case, whichever is sooner, at which point it will be returned to DEC's customers with interest reflected at the overall weighted cost of capital approved in this case of 7.35%. If DEC has not filed an application for a general rate case proceeding by June 22, 2021, it shall file its proposal by that date to flow back to its ratepayers both the protected and the unprotected EDIT generated due to the Tax Act. The federal EDIT flowback proposal should include all workpapers that support the proposed calculations. The Public Staff is specifically requested to file comments on the proposal by no later than July 22, 2021. Other parties also may file comments on the proposal by no later than July 22, 2021.

10. That DEC's request to establish a rider to recover Power Forward costs is denied.

11. That DEC's request, as an alternative to a rider, to establish a regulatory asset for the deferral of Power Forward costs is denied.

12. That DEC is instructed to collaborate with the intervening parties, through the generic and DEC-specific Integrated Resource Planning and Smart Grid Technology Plan docket, toward the goal of resolving some or all of the issues surrounding grid modernization and the most appropriate cost recovery mechanism for such costs.

13. That the Pilot Grid Rider Agreement and Stipulation is disapproved.

14. That the Company shall implement an increment rider, beginning on the effective date of rates in this proceeding, and expiring at the earlier of (a) May 31, 2020,[1] or (b) the last day of the month in which the Company's actual coal inventory levels return to a 35-day supply on a sustained basis, as defined in this Order, to allow the Company to recover the additional costs of carrying coal inventory in excess of a 35-day supply (priced at $73.23 per ton). The Company shall adjust the rider annually, concurrently with its DSM/EE, REPS, and fuel adjustment riders.

15. That on or before March 31, 2019, the Company, in consultation with the Public Staff, shall complete an analysis showing the appropriate coal inventory level given market and generation changes since the Company's rate case in Docket No. E-7, Sub 1026.

16. That the approved base fuel and fuel-related cost factors (excluding regulatory fee), by customer class, are as follows: 1.7828 cents per kWh for the Residential class, 1.9163 cents per kWh for the General Service/Lighting class, and 2.0207 cents per kWh for the Industrial class.

17. That the Company is hereby, authorized to establish a regulatory asset for deferral of post in-service costs for Lee CC, as described herein. These costs shall be amortized over a four-year period.

18. That DEC's request to cancel the Lee Nuclear Project is granted.

19. That DEC's request to recover its project development costs relating to the Lee Nuclear Project is granted, with the exception of costs relating to the Visitors Center and the 2018 AFUDC, as described herein.

20. That the balance of Lee Nuclear Project development costs, adjusted to remove land costs, shall be moved from CWIP Account 107 to regulatory asset Account 182.2 and amortized over a 12-year period, and that the Company shall not earn a return on the unamortized balance.

21. That the Public Staff's proposal that the Company be required to refund to customers $29 million per year relating to the Company's NDTF is hereby, denied.

22. That the depreciation rates proposed by DEC in this case, as modified by this order, are approved.

23. That the aspects of rate design agreed upon in the Stipulation are approved and shall be implemented.

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[1] The Company may request an extension of the May 31, 2020 date.

24. That the Company shall increase the monthly BFC for the residential rate class (Schedules RS, RT, RE, ES and ESA) to $14.00. The BFC for other rate schedules shall remain unchanged.

25. That the Company is hereby authorized to establish a regulatory asset to defer and amortize expenses associated with the Customer Connect project. The regulatory asset account shall accrue AFUDC until the DEC Core Meter-to-Cash release (Releases 5-8) of the Customer Connect project goes into service or January 1, 2023, whichever is sooner. At that point, the costs will be amortized over 15 years.

26. That DEC shall file reports regarding the development, spending, and accomplishments of the Customer Connect project each year by February 15 for the next five years or until the Customer Connect project is fully implemented, whichever occurs later. Further, DEC and the Public Staff shall develop the reporting format for the annual Customer Connect project report and file the format with the Commission within 90 days of this Order.

27. That DEC shall prepare and file a lead-lag study in its next general rate case.

28. That DEC's request to recover its AMI costs of $90.9 million in this proceeding is hereby approved.

29. That within six months of the date of this Order, DEC shall file in this docket the details of proposed new time-of-use, peak pricing, and other dynamic rate structures that will, among other things, allow ratepayers in all customer classes to use the information provided by AMI to reduce their peak-time usage and to save energy.

30. That DEC's costs for AMR meters replaced by AMI shall be recovered over a 15-year period.

31. That the Company's proposal for a JRR, as modified by this Order, and the JRRR are hereby approved for a one-year pilot with an option to renew it for a second year if the Company provides evidence that the JRR is achieving its intended purpose.

32. That the JRR and JRRR revenues shall be reported to the Commission annually, if the JRR is in effect more than one year, and the JRRR shall be reviewed and will be subject to adjustment annually coincident with DEP's December fuel adjustment to match anticipated recovery revenues and true-up any past over-or under-recovery.

33. That due to the uncertain date of implementation, compliance tariffs shall be filed prior to implementation of the JRRR and customers shall be notified by bill insert or message upon implementation.

34. That with respect to the Company's vegetation management program, the Company shall eliminate the 13,467 miles of Existing Backlog, as described herein, within five years after the date rates go into effect in this proceeding.

35. That any accelerated amount of expenditures to eliminate the Existing Backlog shall not be used to increase the level of vegetation management expenses in future proceedings, but shall not prohibit the Company from seeking adjustments for vegetation management contractor increases.

36. That DEC shall provide a report annually to the Commission with the following information: (1) actual 5/7/9 and Existing Backlog miles maintained in the previous calendar year; (2) current level of Existing Backlog miles; (3) vegetation management maintenance dollars budgeted for the previous calendar year for 5/7/9 and Existing Backlog; and (4) vegetation management maintenance dollars expended in the previous calendar year for 5/7/9 and Existing Backlog.

37. That the proposed amendments to DEC's Service Regulations are hereby approved.

38. That the Public Staff shall facilitate discussions with the electric utilities to evaluate and document a basis for continued use of minimum system and to identify specific changes and recommendations as appropriate. If the Public Staff ultimately recommends an alternative approach to minimum system as a result of this review, then the support for that position should be clearly defined. The Public Staff shall submit a report on its findings and recommendations to the Commission no later than the end of the first quarter of 2019 in a new, generic electric utility docket to be established by the Chief Clerk for this purpose.

39. That DEC shall file annual cost of service studies based on Winter Coincident Peak as well as the SCP and SWPA methodologies. In its next general rate case, the Company shall prepare cost of service studies based on each of these methodologies.

40. That DEC's proposal to discontinue Residential Water Heating Service Controlled/Sub Metered Schedule is approved.

41. That DEC shall recover the actual coal ash basin closure costs DEC has incurred during the period from January 1, 2015, through December 31, 2017, in the amount of $545.7 million, to be adjusted based on the allocation factors to be provided by DEC and the Public Staff pursuant to Ordering Paragraph No. 3, and DEC is authorized to establish a regulatory asset as requested in the Company's petition in Docket No. E-7, Sub 1110. These costs shall be amortized over a five-year period, with a return on the unamortized balance and then reducing the resulting annual revenue requirement by $14 million for each of the five years.

42. That DEC shall not be allowed to recover on an ongoing basis $201.3 million in annual coal ash basin closure costs, subject to true-up in future rate cases. DEC is authorized to record its January 1, 2018 and future CCR costs in a deferred account until its next general rate case. This deferral account will accrue a return at the overall rate of return approved in this Order.

43. That within 10 days of the resolution by settlement, dismissal, judgment or otherwise of the litigation entitled Duke Energy Carolinas, LLC, et al. v. AG Insurance SA/NV, et al., Case No. 17 CVS 5594, Superior Court (Business Court), Mecklenburg County, North Carolina (Insurance Case), DEC shall file a report with the Commission explaining the result and

stating the amount of insurance proceeds to be received or recovered by DEC. This reporting requirement shall apply even if the case is appealed to a higher court.

44. That DEC shall place all insurance proceeds received or recovered by DEC in the Insurance Case in a regulatory liability account and hold such proceeds until the Commission enters an order directing DEC regarding the appropriate disbursement of the proceeds. The regulatory liability account shall accrue a carrying charge at the overall rate of return authorized for DEC in this Order.

45. That if DEC receives revenue for any deferred cost for a longer period of time than the amortization period approved by the Commission for that deferred cost, the Company shall continue to record all revenue received for that deferred cost in the specific regulatory asset account established for that deferred cost until the Company's next general rate case.

46. That the Commission's approval in the Order for deferral accounting and other accounting procedures is without prejudice to the right of any party to take issue with the amount of or the accounting treatment accorded these costs in any future regulatory proceeding.

47. That within 30 days of this Order, but no later than ten business days prior to the effective date of the new rates, DEC shall file for Commission approval five copies of all rate schedules designed to comply with this Order, accompanied by calculations showing the revenues that will be produced by the rates for each schedule. This filing shall include a schedule comparing the revenue that was produced by the filed schedules during the test period with the revenue that will be produced under the proposed settlement schedules, and the schedule illustrating the rates of return by class based on the revenues produced by the rates for each schedule.

48. That DEC shall submit a proposed customer notice to the Commission for review and approval, and upon approval of the notice by the Commission, shall give appropriate notice of the approved rate adjustment by mailing the notice to each of its North Carolina retail customers during the billing cycle following the effective date of the new rates.

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of June, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

Commissioner ToNola D. Brown-Bland concurring in part and dissenting in part.
Commissioner Daniel G. Clodfelter concurring in part and dissenting in part.
Commissioner Charlotte A. Mitchell did not participate in this decision.

ELECTRIC – RATE INCREASE

DOCKET NO. E-7, SUB 1146

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	))))	ORDER APPROVING REVISED FUEL COST ADJUSTMENT RIDER

BY THE COMMISSION: On July 31, 2018, Duke Energy Carolinas, LLC (DEC) filed a revised Fuel Cost Adjustment Rider, along with a revised Summary of Rider Adjustments for approval. In its cover letter, DEC indicates that after consultation with the Public Staff, DEC has identified changes needed to its Fuel Cost Adjustment Rider in order for municipal customers on lighting Schedules GL and PL to remain fuel neutral from the fuel rate changes otherwise effective August 1, 2018.

IT IS, THEREFORE, ORDERED that the revised Fuel Cost Adjustment Rider shall be, and is hereby, approved, pro nunc tunc.

ISSUED BY ORDER OF THE COMMISSION.
This the 3rd day of August, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

Commissioner Charlotte A. Mitchell did not participate in this decision.

DOCKET NO. E-7, SUB 1032

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Duke Energy Carolinas, LLC, for Approval of Residential Power Manager Program	)))	ORDER APPROVING PROGRAM MODIFICATIONS

BY THE COMMISSION: On December 28, 2017, Duke Energy Carolinas, LLC (DEC or the Company), filed an application seeking approval of its proposed modifications to its Residential Power Manager Program (Program) and associated tariff under Commission Rule R8-68. The Program was originally approved on October 29, 2013, and is a voluntary demand response program that allows the Company to limit the run time of participating customers' central air conditioning systems.

The proposed modifications to the Program would allow the Company to use a participating customer's thermostat to limit the run time of the customer's central air conditioning system. The Company's specific request is to: 1) include eligible customer- owned "smart" thermostats and related incentives and service charge, and 2) allow DEC to issue incentive payments in a variety of ways, including, but not limited to, bill credits, checks, and prepaid credit cards.

The application includes estimates of the Program's impacts, costs, and benefits used to calculate the cost-effectiveness of the Program. DEC's calculations indicate that the Program will remain cost-effective under the Total Resource Cost, the Utility Cost, and the Rate Impact Measure tests.

The Public Staff presented this matter at the Commission's Regular Staff Conference on February 5, 2018. The Public Staff stated that the Program has the potential to continue to encourage energy efficiency, appears to continue to be cost effective, will be included in future DEC IRPs, and is in the public interest. Therefore, the Public Staff recommended that the Commission approve the Program modifications.

Based on the foregoing and the entire record in this proceeding, the Commission finds good cause to approve the Program modifications. The Commission further finds and concludes that the appropriate ratemaking treatment for the Program, including program costs, net lost revenues, and performance incentives, should be determined in DEC's next annual cost recovery rider to be considered pursuant to Commission Rule R8-69.

IT IS, THEREFORE, ORDERED as follows:

1. That the proposed modifications to the Program are hereby approved pursuant to Commission Rule R8-68.

2. That the Commission shall determine the appropriate ratemaking treatment for the Program, including program costs, net lost revenues, and incentives, in DEC's annual cost recovery rider, in accordance with G.S. 62-133.9 and Commission Rule R8- 69.

3. That DEC shall file with the Commission, within 10 days following the date of this order, a revised tariff showing the effective date of the tariff.

ISSUED BY ORDER OF THE COMMISSION.
This the 7th day of February, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

Commissioner Charlotte A. Mitchell did not participate in this decision.

DOCKET NO. E-7, SUB 1173

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition of Duke Energy Carolinas,	)	
LLC, for Approval of Its Rider US	)	ORDER APPROVING RIDER
(Unmetered Service)	)	

BY THE COMMISSION: On April 13, 2018, Duke Energy Carolinas, LLC (DEC or the Company), filed a request seeking approval of its proposed Unmetered Service rider (Rider US) and waiver of Commission Rule R8-8. Rider US is intended to provide unmetered service to small installations where it is impractical or uneconomical to meter electric service.

Commission Rule R8-8 requires customer bills to show the readings of the meter at the beginning and the end of each billing period. As it would not be possible to provide meter readings on a customer's bill when the service is provided on an unmetered basis, Duke is requesting waiver of this rule.

DEC stated that it was proposing Rider US in response to customer requests for service to small electric loads like wireless internet services and cameras which are mounted on Company-owned lighting poles and posts. DEC also stated that the types of equipment it expects to serve will require no more than 100 watts of electricity.

DEC further stated that the proposed tariff and rates were based on the estimated energy consumption associated with the equipment to be served. Monthly service under Rider US will be provided under Schedule SGS, with the customer paying the basic facilities charges and REPs charges under Schedule SGS, plus the applicable energy charges associated with the equipment installed under Rider US.

The Public Staff presented this matter to the Commission at its Regular Staff Conference on May 7, 2018. The Public Staff also stated that DEC had indicated to the Public Staff that (1) availability was limited to equipment mounted on Company-owned poles because these lighting facilities readily provide the connections needed to serve the equipment without additional facilities; (2) DEC was willing to serve multiple pieces of equipment on the same delivery point, provided the aggregate load of all equipment does not exceed 100 watts; and (3) that DEC's proposed rate structure for Rider US reduces presumed monthly usage for each wattage range by 4 kWh each month in acknowledgement of the lower cost to serve the unmetered loads in question.

Based on the foregoing, the Commission is of the opinion that DEC's request for approval of Rider US and waiver of Commission Rule R8-8 should be granted.

IT IS, THEREFORE, ORDERED that DEC's request to implement its Rider US is hereby approved as filed, waiver of Commission Rule R8-8 is granted, and that within 10 days following the date of this order, DEC shall file with the Commission a revised tariff showing the effective date.

ISSUED BY ORDER OF THE COMMISSION.
This the 7th day of May, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

Commissioner Jerry C. Dockham did not participate in this decision.

DOCKET NO. E-2, SUB 1142
DOCKET NO. E-2, SUB 1153

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1142 In the Matter of Application by Duke Energy Progress, LLC, For Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina DOCKET NO. E-2, SUB 1153 In the Matter of Petition of Duke Energy Progress, LLC, for an Order Approving a Job Retention Rider	ORDER APPROVING JOB RETENTION RIDER TARIFFS AND BILL MESSAGE

BY THE CHAIRMAN: On February 23, 2018, the Commission issued an Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase (Rate Order) in the above-captioned dockets authorizing Duke Energy Progress, LLC (DEP) to adjust its rates and charges for retail electric service in North Carolina. In addition, the Rate Order approved DEP's application to implement a Job Retention Rider (JRR). Ordering Paragraph No. 25 directed DEP to file JRR compliance tariffs and a proposed bill insert or bill message prior to implementing the JRR.

On July 25, 2018, DEP filed its proposed JRR tariffs to be effective for service rendered on and after September 1, 2018, and a proposed bill message.

On August 2, 2018, the Public Staff filed a letter stating that it has reviewed the proposed tariffs and recommends that the Commission approve the tariffs.

Based on the foregoing and the record, the Chairman finds good cause to approve DEP's JRR tariffs and bill message.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 14th day of August, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. E-2, SUB 1170
DOCKET NO. E-7, SUB 1169

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition of Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, Requesting Approval of Green Source Advantage Program and Rider GSA to Implement G.S. 62-159.2	)))))	ORDER ESTABLISHING PROCEEDING TO REVIEW PROPOSED GREEN SOURCE RIDER ADVANTAGE PROGRAM AND RIDER GSA

BY THE CHAIRMAN: On July 27, 2017, House Bill 589 (Session Law 2017-192) was enacted into law. Part III of House Bill 589, enacted as G.S. 62-159.2, requires each electric utility serving more than 150,000 North Carolina retail jurisdictional customers, as of January 1, 2017, to file with the Commission an application requesting approval of a new program to procure renewable energy resources on behalf of North Carolina's major military installations, the University of North Carolina system, and large nonresidential customers served by the offering utility.

On January 22, 2018, in Docket Nos. E-2, Sub 1170, and E-7, Sub 1169, Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC (collectively Duke), jointly filed a proposed Green Source Rider advantage program and rider GSA, consistent with the requirements of Section 3.(b) of House Bill 589.

The Chairman, therefore, finds good cause to initiate this proceeding to review Duke's proposed Green Source Rider advantage program and rider GSA. The Chairman invites interested persons to petition to intervene and to provide comments or suggestions to assist the Commission in its review of Duke's proposed Green Source Rider advantage program and rider GSA.

IT IS, THEREFORE, ORDERED as follows:

1. That the participation of the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e);

2. That other interested persons wishing to become formal parties and participate in this proceeding may file petitions to intervene pursuant to Commission Rules R1-5 and R1-19 on or before February 23, 2018;

3. That the Public Staff and intervenors may file initial comments or suggestions, as provided herein, on or before February 23, 2018;

4. That all parties may file reply comments or suggestions, as provided herein, on or before March 16, 2018; and

5. That, upon receipt of the parties' initial and reply comments, the Commission will proceed appropriately in deciding whether to approve Duke's proposed Green Source Rider advantage program and rider GSA.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of January, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

DOCKET NO. E-2, SUB 1173

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Energy Progress, LLC, Pursuant to N.C.G.S. § 62-133.2 and Commission Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities	)))))	ORDER APPROVING FUEL CHARGE ADJUSTMENT

HEARD: Tuesday, September 18, 2018, at 9:30 a.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding; Commissioner ToNola D. Brown-Bland, Commissioner Jerry C. Dockham, Commissioner James G. Patterson, Commissioner Lyons Gray, Commissioner Daniel G. Clodfelter and Commissioner Charlotte A. Mitchell

APPEARANCES:

For Duke Energy Progress, LLC:

Dwight Allen, Allen Law Offices, PLLC, 1514 Glenwood Avenue, Suite 200 Raleigh, North Carolina 27608

Robert W. Kaylor, Esq., Law Office of Robert W. Kaylor, P.A., 353 E. Six Forks Road, Suite 260, Raleigh, North Carolina 27609

For Carolina Utility Customers Association, Inc:

Robert F. Page, Esq., Crisp & Page, PLLC, 4010 Barrett Drive, Suite 205 Raleigh, North Carolina 27609

For North Carolina Sustainable Energy Association:

Benjamin Smith, Esq., 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For Carolina Industrial Group for Fair Utility Rates II:

Warren K. Hicks, Esq., Bailey & Dixon, L.L.P., Post Office Box 1351, Raleigh, North Carolina 27602

For the Using and Consuming Public:

Robert B. Josey, Jr., Staff Attorney, Public Staff, North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On June 20, 2018, Duke Energy Progress, LLC (Duke Energy Progress, DEP, or the Company), filed an application pursuant to N.C. Gen. Stat. § 62-133.2 and Commission Rule R8-55 regarding fuel and fuel-related cost adjustments for electric utilities, along with the testimony and exhibits of Kendra A. Ward, Eric S. Grant, Joseph A. Miller, Jr., Kelvin Henderson, and Kenneth D. Church.

Petitions to intervene were filed by the North Carolina Sustainable Energy Association (NCSEA) on June 28, 2018, by Carolina Industrial Group for Fair Utility Rates II (CIGFUR) on July 3, 2018, and by Carolina Utility Customers Association, Inc. (CUCA) on July 19, 2018. The Commission granted NCSEA's petition to intervene on June 29, 2018, CIGFUR's petition to intervene on July 6, 2018, and CUCA's petition to intervene on July 24, 2018.

On July 2, 2018, the Commission entered an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice. That Order provided that direct testimony of intervenors should be filed on September 4, 2018, that rebuttal testimony should be filed on September 12, 2018, and that a hearing on this matter would be held on September 18, 2018.

The intervention of the Public Staff is recognized pursuant to N.C. Gen. Stat. § 62-15(d) and Commission Rule R1-19(e). On September 13, 2018, DEP filed affidavits of publication indicating that public notice had been provided in accordance with the Commission's procedural Order issued on July 2, 2018. On August 29, 2018, the Public Staff filed the affidavit of Jenny X. Li and the affidavit of Dustin R. Metz, in accordance with N.C. Gen. Stat. § 62-68. On September 10, 2018, DEP filed a motion requesting that DEP witnesses Kendra A. Ward, Eric Grant, Kenneth D. Church, Kelvin Henderson and Joseph A. Miller, Jr., be excused from appearance at the expert witness hearing, representing that all parties to the proceeding had agreed to waive cross-examination of the witnesses. On September 12, 2018, the Commission granted the motion, excusing DEP witnesses Ward, Grant, Miller, Henderson, and Church from appearing at the expert witness hearing.

The case came on for hearing as scheduled on September 18, 2018. The application, prefiled direct testimony and exhibits of DEP's witnesses and the prefiled affidavits of the Public Staff's witnesses were received into evidence. No other party presented witnesses, and no public witnesses appeared at the hearing. The Public Staff and DEP filed a joint proposed order on October 18, 2018.

Based upon the Company's verified application, the testimony, affidavits, and exhibits received into evidence at the hearing, the affidavits of the Public Staff and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. Duke Energy Progress is a duly organized corporation existing under the laws of the State of North Carolina, is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North Carolina, and is subject to the jurisdiction of the Commission as a public utility. Duke Energy Progress is lawfully before this Commission based upon its application filed pursuant to N.C. Gen. Stat. § 62-133.2.

2. The test period for purposes of this proceeding is the 12 months ended March 31, 2018 (test period).

3. In its application and testimony in this proceeding, DEP requested a total increase of approximately $226 million to its North Carolina retail revenue requirement associated with fuel and fuel-related costs, excluding the regulatory fee. The fuel and fuel-related cost factors requested by DEP included Experience Modification Factor (EMF) riders to take into account fuel and fuel-related cost under-recoveries experienced during the test period of approximately $224. This includes the deferred under-recovered balance of approximately $42 million carried forward from the prior year's filing in Docket No. E-2, Sub 1146.

4. The Company's baseload plants were generally managed prudently and efficiently during the test period so as to minimize fuel and fuel-related costs.

5. The Company's fuel and reagent procurement and power purchasing practices during the test period were reasonable and prudent.

6. The test period per book system sales are 62,453,151 megawatt-hours (MWh). The test period per book system generation (net of auxiliary use and joint owner generation) and purchased power is 70,851,204 MWh and is categorized as follows:

Net Generation Type	MWh
Coal	9,240,778
Natural Gas, Oil and Biomass	22,933,359
Nuclear	29,666,537
Hydro – Conventional	587,221
Solar	247,821
Purchased Power – subject to economic dispatch or curtailment	3,549,071
Other Purchased Power	4,626,417
Total Net Generation (may not add to sum due to rounding)	70,851,204

7. The appropriate nuclear capacity factor for use in this proceeding is 94.1%.

8. The North Carolina retail test period sales, adjusted for customer growth and weather, for use in calculating the EMF are 37,259,304 MWh. The adjusted North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Adjusted MWh Sales
Residential	15,621,843
Small General Service	1,891,451
Medium General Service	11,038,646
Large General Service	8,346,128
Lighting	361,235
Total (may not add to sum due to rounding)	37,259,304

9. The projected billing period (December 2018-November 2019) sales for use in this proceeding are 62,133,368 MWh on a system basis and 37,659,805 MWh on a North Carolina retail basis. The projected billing period North Carolina retail customer class MWh sales are as follows:

N.C. Retail Customer Class	Projected MWh Sales
Residential	15,956,916
Small General Service	1,795,996
Medium General Service	10,351,641
Large General Service	9,176,034
Lighting	379,219
Total (may not add to sum due to rounding)	37,659,805

10. The projected billing period system generation and purchased power for use in this proceeding in accordance with projected billing period system sales is 68,667,857 MWh and is categorized as follows:

Generation Type	MWh
Coal	5,721,568
Gas Combustion Turbine (CT) and Combined Cycle (CC)	22,506,145
Nuclear	29,210,311
Hydro	606,686
Solar	304,154
Purchased Power	10,318,993
Total (may not add to sum due to rounding)	68,667,857

11. The appropriate fuel and fuel-related prices and expenses for use in this proceeding to determine projected system fuel expense are as follows:

A. The coal fuel price is $33.54/MWh.
B. The gas CT and CC fuel price is $29.04/MWh.
C. The appropriate expense for ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions (collectively, Reagents) is $14,989,402.
D. The total nuclear fuel price (including Joint Owners generation) is $6.72/MWh.
E. The total system purchased power cost (including the impact of Joint Dispatch Agreement (JDA) Savings Shared and the impact of House Bill 589, N.C. Sess. L. 2017-192), is $529,383,055.
F. System fuel expense recovered through intersystem sales is $105,350,249.

12. The projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $844,290,141.

13. The Company's appropriate North Carolina retail jurisdictional fuel and fuel-related expense under-collection for purposes of the EMF was $224,334,099, consisting of under-recoveries of $89,796,902; $6,865,500; $37,833,573; $86,641,717 and $3,196,403, for the Residential, Small General Service, Medium General Service, Large General Service, and Lighting classes, respectively. These amounts include the deferred under-recovered balance from the prior year as follows: $21,282,684; $1,023,834; $17,750,323 and $1,807,912 for the Residential, Small General Service, Large General Service, and Lighting classes, respectively.

14. The increase in customer class fuel and fuel-related cost factors from the amounts approved in Docket No. E-2, Sub 1146 should be allocated among the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology that was approved by the Commission in that docket.

15. The appropriate prospective fuel and fuel-related cost factors for this proceeding for each of DEP's rate classes, excluding the regulatory fee, are as follows: 2.311¢/kilowatt-hour (kWh) for the Residential class; 2.556¢/kWh for the Small General Service class; 2.477¢/kWh for the Medium General Service class; 1.757¢/kWh for the Large General Service class; and 2.251¢/kWh for the Lighting class.

16. The appropriate EMFs established in this proceeding, excluding the regulatory fee, are as follows: 0.575¢/kWh for the Residential class; 0.363¢/kWh for the Small General Service class; 0.343¢/kWh for the Medium General Service class; 1.038¢/kWh for the Large General Service class; and 0.885¢/kWh for the Lighting class.

17. The total net fuel and fuel-related cost factors for this proceeding for each of DEP's rate classes, excluding the regulatory fee, are as follows: 2.886¢/kWh for the Residential class; 2.919¢/kWh for the Small General Service class; 2.820¢/kWh for the Medium General Service class; 2.795¢/kWh for the Large General Service class; and 3.136¢/kWh for the Lighting class.

18. In this proceeding, DEP included a rate to recover a revenue deficiency related to a fuel EMF that expired and was removed from billed rates on November 30, 2017, but was inadvertently included in the calculation of the compliance rates filed effective March 16, 2018, in DEP's general rate case, Docket No. E-2, Sub 1142. The following rates by class for the EMF Deficiency Rider will be in effect for a 12-month period expiring on and after November 30, 2019: 0.022¢/kWh for the Residential class; 0.052¢/kWh for the Small General Service class; 0:068¢/kWh for the Medium General Service class; 0.002¢/kWh for the Large General Service class; and (0.046)¢/kWh for the Lighting class.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This Finding of Fact is essentially informational, procedural, and jurisdictional in nature and is uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

Section 62-133.2(c) of the North Carolina General Statutes sets out the verified, annualized information that each electric utility is required to furnish to the Commission in an annual fuel and fuel-related cost adjustment proceeding for a historical 12-month test period. Commission Rule R8-55(b) prescribes the 12 months ending March 31 as the test period for DEP. The Company's filing in this proceeding was based on the 12 months ended March 31, 2018.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence for this Finding of Fact is contained in the application, the direct testimony of Company witness Ward and the entire record in this proceeding. This finding is not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence for this Finding of Fact is contained in the testimony of Company witnesses Henderson and Miller, and the affidavit of Public Staff affiant Metz.

Commission Rule R8-55(d)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent North American Electric Reliability Corporation (NERC)

Generating Availability Report, adjusted to reflect the unique, inherent characteristics of the utility facilities and any unusual events. Company witness Henderson testified that DEP's nuclear fleet consists of three generating stations and a total of four units. He testified that the Company's four nuclear units operated at a system average capacity factor of 95.67% during the test period. This capacity factor, as well as the Company's 2-year average capacity factor of 94.66%, exceeded the five-year industry weighted average capacity factor of 90.03% for the period 2012-2016 for average comparable units on a capacity-rated basis, as reported by NERC in its latest Generating Unit Statistical Brochure.

Company witness Miller testified concerning the performance of DEP's fossil/hydro assets. He stated that the Company's generating units operated efficiently and reliably during the test period. He explained that several key measures are used to evaluate operational performance, depending on the generator type: (1) equivalent availability factor (EAF), which refers to the percentage of a given time period a facility was available to operate at full power, if needed (EAF is not affected by the manner in which the unit is dispatched or by the system demands; it is impacted, however, by planned and unplanned (*i.e.*, forced) outage time); (2) net capacity factor (NCF), which measures the generation that a facility actually produces against the amount of generation that theoretically could be produced in a given time period, based upon its maximum dependable capacity (NCF *is* affected by the dispatch of the unit to serve customer needs); (3) equivalent forced outage rate (EFOR), which represents the percentage of unit failure (unplanned outage hours and equivalent unplanned derated hours); a low EFOR represents fewer unplanned outage and derated hours, which equates to a higher reliability measure; and (4) starting reliability, which represents the percentage of successful starts.

Witness Miller presented the following chart, which shows operational results, categorized by generator type, as well as results from the most recently published NERC Generating Unit Statistical Brochure for the period 2012 through 2016:

Generator Type	Measure	Review Period DEP Operational Results	2012-2016 NERC Average	Nbr of Units
Coal-Fired Test Period	EAF	78.0%	82.0%	446
	NCF	29.6%	58.3%	
	EFOR	8.0%	7.6%	
Coal-Fired Summer Peak	EAF	90.5%	n/a	n/a
Total CC Average	EAF	85.2%	84.8%	301
	NCF	78.0%	53.0%	
	EFOR	0.69%	5.5%	
Total CT Average	EAF	79.4%	87.6%	826
	SR	98.2%	98.1%	
Hydro	EAF	95.8%	81.1%	1,120

Company witness Miller also testified that the Company, like other utilities across the United States, has experienced a change in the dispatch order for each type of generating facility due to continued favorable economics resulting from the lower pricing of natural gas. Gas-fired facilities provided 69% of the DEP fossil/hydro generation during the test period.

The Commission finds and concludes that DEP generally managed its baseload plants prudently and efficiently to minimize fuel and fuel-related costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

Commission Rule R8-52(b) requires each electric utility to file a Fuel Procurement Practices Report at least once every 10 years and each time the utility's fuel procurement practices change. The Company's revised fuel procurement practices were filed with the Commission in Docket No. E-100, Sub 47A in 2008, and were in effect throughout the 12 months ending March 31, 2018. In addition, the Company files monthly reports of its fuel and fuel-related costs pursuant to Commission Rule R8-52(a). Further evidence for this Finding of Fact is contained in the testimony of Company witnesses Ward, Grant, Miller, and Church.

Company witness Ward testified that DEP's fuel procurement strategies that mitigate volatility in supply costs are a key factor in DEP's ability to maintain lower fuel and fuel-related rates. Other key factors include DEP's diverse generating portfolio mix of nuclear, coal, natural gas, and hydro; lower natural gas and coal prices; the capacity factors of its nuclear fleet; the combination of DEP's and DEC's respective skills in procuring, transporting, managing and blending fuels and procuring reagents; the increased and broader purchasing ability of the combined companies; and the joint dispatch of DEP's and DEC's generation resources.

Company witness Grant described DEP's fossil fuel procurement practices, set forth in Grant Exhibit 1. Those practices include computing near and long-term consumption forecasts, determining and designing inventory targets, inviting proposals from all qualified suppliers, awarding contracts based on the lowest evaluated offer, monitoring delivered coal volume and quality against contract commitments, and conducting short-term and spot purchases to supplement term supply.

According to witness Grant, the Company's average delivered coal cost per ton increased approximately 1%, from $80.26 per ton in the prior test period to $80.82 per ton in the test period. The Company's transportation costs increased approximately 5%, from $28.03 per ton in the prior test period to $29.42 per ton in the test period.

Witness Grant stated that DEP's current coal burn projection for the billing period is 2.3 million tons compared to 3.9 million tons consumed during the test period. DEP's billing period projections for coal generation may be impacted due to changes from, but not limited to, the following factors: delivered natural gas prices versus the average delivered cost of coal, volatile power prices, and electric demand. Combining coal and transportation costs, DEP projects average delivered coal costs of approximately $81.65 per ton for the billing period compared to $80.82 per ton in the test period.

According to witness Grant, DEP continues to maintain a comprehensive coal and natural gas procurement strategy that has proven successful over the years in limiting average annual fuel price changes while actively managing the dynamic demands of its fossil fuel generation fleet in a reliable and cost-effective manner.

Witness Grant further testified that DEP's current natural gas burn projection for the billing period is approximately 171.8 million MMBtu, which is an increase from the 169.4 million MMBtu consumed during the test period. The current average forward Henry Hub price for the billing period is $2.81 per MMBtu, compared to $3.03 per MMBtu in the test period. Witness Grant also testified that the Company's average price of gas purchased for the test period was $4.68 per MMBtu, compared to $4.00 per MMBtu in the prior test period, representing an increase of approximately 17%.

Pursuant to N.C. Gen. Stat. § 62-133.2(a1)(3), DEP is allowed to recover the cost of "ammonia, lime, limestone, urea, dibasic acid, sorbents, and catalysts consumed in reducing or treating emissions." Company witness Miller testified that the Company's fossil/hydro/solar generation portfolio consists of 9,268 MWs of generating capacity, 3,544 MWs of which is coal-fired generation across three generating stations and a total of seven units. These units are equipped with emission control equipment, including selective catalytic reduction (SCR) equipment for removing nitrogen oxides (NOx), flue gas desulfurization (FGD or scrubber) equipment for removing sulfur dioxide (SO_2), and low NOx burners. This inventory of coal-fired assets with emission control equipment enhances DEP's ability to maintain current environmental compliance and concurrently utilize coal with increased sulfur content, thereby providing flexibility for DEP to procure the most cost-effective options for fuel supply.

Company witness Miller further testified that overall, the type and quantity of chemicals used to reduce emissions at the plants vary depending on the generation output of the unit, the chemical constituents in the fuel burned, and/or the level of emissions reduction required.

Company witness Church testified that DEP's nuclear fuel procurement practices involve computing near and long-term consumption forecasts, establishing nuclear system inventory levels, projecting required annual fuel purchases, requesting proposals from qualified suppliers, negotiating a portfolio of long-term contracts from diverse sources of supply, and monitoring deliveries against contract commitments. Witness Church explained that for uranium concentrates, conversion, and enrichment services, long-term contracts are used extensively in the industry to cover forward requirements and ensure security of supply. He also stated that, throughout the industry, the initial delivery under new long-term contracts commonly occurs several years after contract execution. For this reason, DEP relies extensively on long-term contracts to cover the largest portion of its forward requirements. By staggering long-term contracts over time for these components of the nuclear fuel cycle, DEP's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out the Company's exposure to price volatility. He further stated that diversifying fuel suppliers reduces DEP's exposure to possible disruptions from any single source of supply. Due to the technical complexities of changing fabrication services suppliers, DEP generally sources these services to a single domestic supplier on a plant-by-plant basis using multi-year contracts.

Under N.C. Gen. Stat. §§ 62-133.2(a1)(4), (5), (6), and (7), utilities are permitted to recover the cost of non-capacity power purchases subject to economic dispatch or economic curtailment; capacity costs of power purchases associated with qualifying facilities subject to economic dispatch; certain costs associated with power purchases from renewable energy facilities; and the fuel costs of other power purchases. Company witness Grant testified that DEP and DEC utilize the same process to ensure that the assets of the Companies are reliably and economically available to serve their respective customers. To that end, both companies consider numerous factors such as the latest forecasted fuel prices, transportation rates, planned maintenance and refueling outages at the generating units, estimated forced outages at generating units based on historical trends, generating unit performance parameters, and expected market conditions associated with power purchases and off-system sales opportunities in order to determine the most economic and reliable means of serving their customers.

No party presented testimony contesting the Company's fuel and reagent procurement and power purchasing practices. Based upon the fuel procurement practices report, the evidence in the record, and the absence of any testimony to the contrary, the Commission finds and concludes that these practices were reasonable and prudent during the test period.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness Ward.

According to the exhibits sponsored by Company witness Ward, the test period per book system sales were 62,453,151 MWh, and test period per book system generation and purchased power amounted to 70,851,204 MWh (net of auxiliary use and joint owner generation). The test period per book system generation and purchased power are categorized as follows (Ward Exhibit 7):

Net Generation Type	MWh
Coal	9,240,778
Natural Gas, Oil and Biomass	22,933,359
Nuclear	29,666,537
Hydro – Conventional	587,221
Solar	247,821
Purchased Power – subject to economic dispatch or curtailment	3,549,071
Other Purchased Power	4,626,417
Total Net Generation (may not add to sum due to rounding)	70,851,204

The evidence presented regarding the operation and performance of the Company's generation facilities is discussed in the Evidence and Conclusions for Finding of Fact No. 4.

No party contested witness Ward's exhibits setting forth per books system sales, generation by fuel type, and purchased power. Therefore, based on the evidence presented and noting the absence of evidence presented to the contrary, the Commission finds and concludes that the per books levels of test period system sales of 62,453,151 MWh and system generation and purchased power of 70,851,204 MWh are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence supporting this Finding of Fact is contained in the testimony and exhibits of Company witness Henderson and the affidavit of Public Staff witness Metz.

Commission Rule R8-55(d)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent NERC Generating Availability Report, adjusted to reflect the unique, inherent characteristics of the utility's facilities and any unusual events. The Company proposed using a 94.1% capacity factor in this proceeding based on the operational history of the Company's nuclear units, and the number of planned outage days scheduled during the 2018-2019 billing period. This proposed capacity factor exceeds the five-year industry weighted average capacity factor of 90.03% for the period 2012-2016 for average comparable units on a capacity-rated basis, as reported by NERC in its latest Generating Availability Report. Public Staff affiant Metz did not dispute the Company's proposed use of a 94.1% capacity factor.

Based upon the requirements of Commission Rule R8-55(d)(1), the historical and reasonably expected performance of the DEP system, and the fact that no party disputed the Company's proposed capacity factor, the Commission finds and concludes that the 94.1% nuclear capacity factor, and its associated generation of 29,210,311 MWh, are reasonable and appropriate for determining the appropriate fuel and fuel-related costs in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8-10

The evidence supporting these Findings of Fact is contained in the testimony and exhibits of Company witness Ward.

On her Exhibit 4, Company witness Ward set forth the test year per books North Carolina retail sales, adjusted for weather and customer growth, of 37,259,304 MWh, comprised of Residential class sales of 15,621,843 MWh, Small General Service sales of 1,891,451 MWh, Medium General Service sales of 11,038,646 MWh, Large General Service sales 8,346,128 MWh, and Lighting class sales of 361,235 MWh.

Witness Ward used projected billing period system sales, generation, and purchased power to calculate the proposed prospective component of the fuel and fuel-related cost factors. The projected system sales level used, as set forth on Ward Exhibit 2, Schedule 1, is 62,133,368 MWh. The projected level of generation and purchased power used was 68,667,857 MWh (calculated using the 94.1% capacity factor found reasonable and appropriate above), and was broken down by witness Ward as follows, as set forth on that same schedule:

Generation Type	MWh
Coal	5,721,568
Gas Combustion Turbine and Combined Cycle	22,506,145
Nuclear	29,210,311
Hydro	606,686
Solar	304,154
Purchased Power	10,318,993
Total (may not add to sum due to rounding)	68,667,857

As part of her Workpaper 7, Company witness Ward also presented an estimate of the projected billing period North Carolina retail Residential, Small General Service, Medium General Service, Large General Service, and Lighting MWh sales. The Company estimated billing period North Carolina retail MWh sales to be as follows:

N.C. Retail Customer Class	Projected MWh Sales
Residential	15,956,916
Small General Service	1,795,996
Medium General Service	10,351,641
Large General Service	9,176,034
Lighting	379,219
Total (may not add to sum due to rounding)	37,659,805

These class totals were used in Ward Exhibit 2, Schedule 1, in calculating the total fuel and fuel-related cost factors by customer class.

Based on the evidence presented by the Company, the Public Staff's acceptance of the amounts presented by the Company, and the absence of evidence presented to the contrary, the Commission finds and concludes that the projected North Carolina retail levels of sales set forth in the Company's exhibits (normalized for customer growth and weather), as well as the projected levels of generation and purchased power, are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 11

The evidence supporting this Finding of Fact is contained in the testimony and exhibits of Company witnesses Ward and Grant, and the affidavit of Public Staff witness Metz.

In her Exhibit 2, Schedule 1, Company witness Ward recommended the fuel and fuel-related prices and expenses. The total adjusted system fuel and fuel-related expense, based in part on the use of these amounts, is utilized to calculate the prospective fuel and fuel-related cost factors recommended by the Company and the Public Staff.

In his affidavit, Public Staff witness Metz stated that, based on his investigation, the projected fuel and fuel-related costs (including reagents) set forth in DEP's application and testimony are reasonable and in accordance with the requirements of N.C. Gen. Stat. § 62-133.2.

No other party presented evidence on the level of DEP's fuel and fuel-related prices and expenses.

Based upon the evidence in the record as to the appropriate fuel and fuel-related prices and expenses, the Commission finds and concludes that the fuel and fuel-related prices recommended by Company witness Ward and accepted by the Public Staff for purposes of determining projected system fuel expense are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence supporting this Finding of Fact is contained in the testimony and exhibits of Company witness Ward and the affidavit of Public Staff witness Metz.

According to Ward Exhibit 2, Schedule 1, the projected fuel and fuel-related costs for the North Carolina retail jurisdiction for use in this proceeding are $844,290,141. Public Staff witness Metz did not take issue with her calculation.

Aside from the Company and the Public Staff, no other party presented or elicited testimony contesting the Company's projected fuel and fuel-related costs for the North Carolina retail jurisdiction. Based upon the evidence in the record and the absence of any direct testimony to the contrary, the Commission finds and concludes that the Company's projected total fuel and fuel-related cost for the North Carolina retail jurisdiction of $844,290,141 is reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 13-17

The evidence supporting these Findings of Fact is contained in the testimony and exhibits of Company witness Ward, the affidavits of Public Staff witnesses Li and Metz.

Company witness Ward presented DEP's fuel and fuel-related expense (over)/under-collection and prospective fuel and fuel-related cost factors. Company witness Ward's testimony sets forth the projected fuel and fuel-related costs, the amount of (over)/under-collection for purposes of the EMF, the method for allocating the decrease in fuel and fuel-related costs, the composite fuel and fuel-related cost factors, and the EMFs, along with revised exhibits and work papers. Public Staff witness Li agreed that DEP's EMF increment/(decrement) riders for each customer class should be approved based on the following under-recoveries, including the previously deferred under-recovery of $42 million from the prior year fuel proceeding, Docket No. E-2, Sub 1146:

N.C. Retail Customer Class	Under - Recovery
Residential	$89,796,902
Small General Service	6,865,500
Medium General Service	37,833,573
Large General Service	86,641,717
Lighting	3,196,403
Total (may not add to sum due to rounding)	$224,334,099

As a result of these amounts, Public Staff witnesses Li and Metz recommended approval of the following EMF increment/(decrement) billing factors, excluding the regulatory fee:

N.C. Retail Customer Class	EMF Increment/ (Decrement) (cents/kWh)
Residential	0.575
Small General Service	0.363
Medium General Service	0.343
Large General Service	1.038
Lighting	0.885

The Commission finds and concludes that the EMF increment/(decrement) billing factors set forth in the affidavit of Public Staff witness Li and the affidavit of Public Staff witness Metz are reasonable and appropriate for use in this proceeding.

Company witness Ward calculated the Company's proposed fuel and fuel-related cost factors using a uniform bill adjustment method. She stated that the increase in fuel costs from the amounts approved in Docket No. E-2, Sub 1146 should be allocated among the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology utilized in past DEP fuel cases approved by the Commission. No party opposed the use of this allocation method. Public Staff witness Metz recommended the approval of the prospective and total fuel and fuel-related cost factors (excluding regulatory fee) set forth in the Company's application and the testimony of witness Ward.

Based upon the testimony and exhibits in the record, the Commission finds and concludes that DEP's projected fuel and fuel-related cost of $844,290,141 for the North Carolina retail jurisdiction for use in this proceeding is reasonable. The Commission also finds and concludes that the EMF increment/(decrement) riders and the EMF interest decrement rider for each class set forth in the affidavit of Public Staff witness Li and the affidavit of Public Staff witness Metz in this proceeding, excluding the regulatory fee, and the Public Staff's prospective fuel and fuel-related cost factors proposed in this proceeding for each of the rate classes, are appropriate. Additionally, the Commission finds and concludes that DEP's increase in fuel and fuel-related costs from the amounts approved in Docket No. E-2, Sub 1146 should be allocated among the rate classes on a uniform percentage basis, using the uniform bill adjustment methodology approved by this Commission in DEP's past fuel cases.

The test period and projected fuel and fuel-related costs, and the proposed factors, including the EMFs, are not opposed by any party. Accordingly, the overall fuel and fuel-related cost calculation, incorporating the conclusions reached herein, results in net fuel and fuel-related cost factors of 2.886¢/kWh for the Residential class, 2.919¢/kWh for the Small General Service class, 2.820¢/kWh for the Medium General Service class, 2.795¢/kWh for the Large General Service class, and 3.136¢/kWh for the Lighting class, excluding regulatory fee, consisting of the prospective fuel and fuel-related cost factors of 2.311¢/kWh, 2.556¢/kWh, 2.477¢/kWh, 1.757¢/kWh, and 2.251¢/kWh, EMF increments/(decrements) of 0.575¢, 0.363¢, 0.343¢, 1.038¢, and 0.885¢/kWh, and EMF interest decrements of 0.000¢/kWh, 0.000¢/kWh, 0.000¢/kWh, 0.000¢/kWh and 0.000¢/kWh for the Residential, Small General Service, Medium General

Service, Large General Service, and Lighting classes, respectively, all excluding the regulatory fee. The billing factors, both excluding and including the regulatory fee, are shown in Appendix A to this Order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

The evidence supporting this Finding of Fact is contained in the testimony and exhibits of Company witness Ward.

Company witness Ward testified that a revenue deficiency had resulted from a fuel EMF that expired and was removed from billed rates on November 30, 2017, but was inadvertently included in the calculation of compliance rates filed effective March 16, 2018, in DEP's general rate case, Docket No. E-2, Sub 1142. Witness Ward further testified that this under-collection without interest for the time period March 16, 2018 – May 31, 2018 will be recovered over a 12-month period expiring on and after November 30, 2019. The proposed EMF Deficiency Riders by class are as follows: 0.022¢/kWh for the Residential class; 0.052¢/kWh for the Small General Service class; 0.068¢/kWh for the Medium General Service class; 0.002¢/kWh for the Large General Service class; and (0.046)¢/kWh for the Lighting class.

Based on the evidence presented by DEP, and noting the absence of evidence presented to the contrary by any other party, the Commission finds and concludes that the Company's fuel EMF deficiency rider rates are reasonable.

IT IS, THEREFORE, ORDERED as follows:

1. That effective for service rendered on and after December 1, 2018, DEP shall adjust the base fuel and fuel-related cost factors in its North Carolina retail rates, as approved in Docket No. E-2, Sub 1142, amounting to 1.993¢/kWh for the Residential class, 2.088¢/kWh for the Small General Service class, 2.431¢/kWh for the Medium General Service class, 2.253¢/kWh for the Large General Service class, and 0.596¢/kWh for the Lighting class (all excluding the regulatory fee), by amounts equal to 0.318¢/kWh, 0.468¢/kWh, 0.046¢/kWh, (0.496)¢/kWh and 1.655¢/kWh, respectively, and further, that DEP shall adjust the resulting approved prospective fuel and fuel-related cost factors by EMF increments/(decrements) of 0.575¢/kWh for the Residential class, 0.363¢/kWh for the Small General Service class, 0.343¢/kWh for the Medium General Service class, 1.038¢/kWh for the Large General Service class, and 0.885¢/kWh for the Lighting class (excluding the regulatory fee) and EMF interest decrements of 0.000¢/kWh for the Residential class, 0.000¢/kWh for the Small General Service class, 0.000¢/kWh for the Medium General Service class, and 0.000¢/kWh for the Large General Service class (excluding the regulatory fee). The EMF increments are to remain in effect for service rendered through November 30, 2019;

2. That effective for service rendered on and after December 1, 2018, DEP shall bill the following fuel EMF Deficiency Riders: 0.022¢/kWh for the Residential class; 0.052¢/kWh for the Small General Service class; 0.068¢/kWh for the Medium General Service class; 0.002¢/kWh for the Large General Service class; and (0.046)¢/kWh for the Lighting class;

3. That DEP shall file appropriate rate schedules and riders with the Commission in order to implement these approved rate adjustments as soon as practicable; and

4. That DEP shall work with the Public Staff to jointly prepare a proposed notice to customers of the rate adjustments ordered by the Commission in Docket Nos. E-2, Subs 1173, 1175, and 1176 and the Company shall file the proposed notice to customers for Commission approval as soon as practicable.

ISSUED BY ORDER OF THE COMMISSION.
This the 8th day of November, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

Appendix A

EXCLUDING REGULATORY FEE

	A	B	C	D	E	F
Class	Base Fuel Rate	Decrement to Base Fuel Rate	Prospective Rate (Columns A + B)	EMF Increment/ (Decrement)	EMF Interest (Decrement)	Billed Rate(Cols. C + D + E)
Residential	1.993	0.318	2.311	0.575	-	2.886
Small General Service	2.088	0.468	2.556	0.363	-	2.919
Medium General Service	2.431	0.046	2.477	0.343	-	2.820
Large General Service	2.253	(0.496)	1.757	1.038	-	2.795
Lighting	0.596	1.655	2.251	0.885	-	3.136

INCLUDING REGULATORY FEE

	A	B	C	D	E	F
Class	Base Fuel Rate	Decrement to Base Fuel Rate	Prospective Rate (Columns A + B)	EMF Increment/ (Decrement)	EMF Interest (Decrement)	Billed Rate(Cols. C + D + E)
Residential	1.996	0.318	2.314	0.576	-	2.890
Small General Service	2.091	0.469	2.560	0.364	-	2.924
Medium General Service	2.434	0.046	2.480	0.343	-	2.823
Large General Service	2.256	(0.497)	1.759	1.039	-	2.798
Lighting	0.597	1.657	2.254	0.886	-	3.140

ELECTRIC -- RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

DOCKET NO. E-2, SUB 1174

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Progress, LLC,	)	
for Approval of Demand-Side Management	)	ORDER APPROVING
and Energy Efficiency Cost Recovery Rider	)	DSM/EE RIDER AND REQUIRING
Pursuant to N.C. Gen. Stat. § 62-133.9 and	)	FILING OF CUSTOMER NOTICE
Commission Rule R8-69	)	

HEARD: Tuesday, September 18, 2018, in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding; Chairman Edward S. Finley, Jr.; Commissioners Jerry C. Dockham, James G. Patterson, Lyons Gray, Daniel G. Clodfelter, and Charlotte A. Mitchell

APPEARANCES:

For Duke Energy Progress, LLC:

Kendrick C. Fentress, Associate General Counsel, Duke Energy Corporation 401 South Wilmington Street, Raleigh, North Carolina 27602

For the Carolina Utility Customers Association, Inc.:

Robert F. Page, Crisp & Page, PLLC, 4010 Barrett Drive, Suite 205, Raleigh, North Carolina 27609

For the Carolina Industrial Group for Fair Utility Rates II:

Warren K. Hicks, Bailey & Dixon, LLP, 434 Fayetteville Street, Suite 2500, Raleigh, North Carolina 27602

For the North Carolina Sustainable Energy Association:

Benjamin Smith, Regulatory Counsel, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For the North Carolina Justice Center, Southern Alliance for Clean Energy, Natural Resource Defense Council, and North Carolina Housing Coalition:

David Neal, Senior Attorney, Southern Environmental Law Center, 601 West Rosemary Street, Suite 220, Chapel Hill, North Carolina 27516

For the Using and Consuming Public:

Lucy E. Edmondson and Heather D. Fennell, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699

BY THE COMMISSION: Pursuant to N.C. Gen. Stat. § 62-133.9(d) the North Carolina Utilities Commission (Commission) is authorized to approve an annual rider to the rates of electric public utilities, outside of a general rate case, for recovery of all reasonable and prudent costs incurred for adoption and implementation of new demand-side management (DSM) and energy efficiency (EE) measures. The Commission is also authorized to award incentives to electric companies for adopting and implementing new DSM/EE measures, including, but not limited to, appropriate rewards based on (1) the sharing of savings achieved by the DSM and EE measures and/or (2) the capitalization of a percentage of avoided costs achieved by the measures. Commission Rule R8-69(b) provides that every year the Commission will conduct a proceeding for each electric public utility to establish an annual DSM/EE rider to recover the reasonable and prudent costs incurred by the electric utility in adopting and implementing new DSM/EE measures previously approved by the Commission pursuant to Commission Rule R8-68. Further, Commission Rule R8-69(b) provides for the establishment of a DSM/EE experience modification factor (EMF) rider to allow the electric public utility to collect the difference between reasonable and prudently incurred costs and the revenues that were actually realized during the test period under the DSM/EE rider then in effect. Commission Rule R8-69(c) permits the utility to request the inclusion of utility incentives (the rewards authorized by the statute), including net lost revenues (NLR), in the DSM/EE rider and the DSM/EE EMF rider.

On June 20, 2018, Duke Energy Progress, LLC (DEP or the Company), filed an application for approval of its annual DSM/EE cost recovery rider (Application) pursuant to N.C. Gen. Stat. § 62-133.9 and Commission Rule R8-69. Along with the Application, DEP filed the associated testimony and exhibits of Carolyn T. Miller and Robert P. Evans in support of recovery of DSM/EE costs and utility incentives forecasted for the rate period of January 1, 2019 through December 31, 2019, including program expenses, amortizations and carrying costs associated with deferred prior period costs, Distribution System Demand Response (DSDR) depreciation and capital costs, NLR, and program and portfolio performance incentives (PPI). In addition, DEP asked for approval of an EMF component of its DSM/EE rider to true-up its actual DSM/EE costs and utility incentives during the test period of January 1, 2017 through December 31, 2017.

On July 2, 2018, the Commission issued an order scheduling a public hearing in this matter for September 18, 2018, establishing discovery guidelines, providing for intervention and testimony by other parties, and requiring public notice (Scheduling Order). On September 13, 2018, DEP filed its affidavits of publication indicating that the Company had provided notice in newspapers of general circulation as required by the Commission's Scheduling Order.

The intervention of the Public Staff is recognized pursuant to N.C. Gen. Stat. § 62-15(d) and Commission Rule R1-19(e). On June 28, 2018, the North Carolina Sustainable Energy Association (NCSEA) filed a petition to intervene, which was granted by Commission order on June 29, 2018. On July 3, 2018, the Carolina Industrial Group for Fair Utility Rates II (CIGFUR II) filed a petition to intervene, which was granted by Commission order on July 6, 2018. On

July 19, 2018, the Carolina Utility Customers Association, Inc. (CUCA) filed a petition to intervene, which was granted by Commission order on July 24, 2018. On August 2, 2018, the North Carolina Justice Center, Southern Alliance for Clean Energy, Natural Resources Defense Council, and North Carolina Housing Coalition (collectively, NC Justice Center) filed a petition to intervene, which was granted by Commission order on August 14, 2018.

On September 4, 2018, NC Justice Center filed the testimony and exhibits of Christopher Neme, and the Public Staff filed the testimony and exhibits of Michael C. Maness, David M. Williamson, and John R. Hinton.

On September 10, 2018, DEP filed the supplemental testimony and exhibits of witness Miller and the supplemental exhibits of witness Evans (Supplemental Filing). The Supplemental Filing supported adjustments to the PPI relating to Vintage 2016 and Vintage 2017 of the EnergyWise for Business program; adjustments to Vintage 2016 and Vintage 2017 lost revenues to align with the final outcome of DEP's most recent general rate case in Docket No. E-2, Sub 1142; and adjustments to the valuation of Vintage 2017 lost revenues allocated to the non-residential lighting program.

Also on September 10, 2018, the Company filed a Motion for Additional Public Hearing and Public Notice of Revised Proposed Rates. On September 11, 2018, the Commission issued an order scheduling an additional public hearing in this matter for October 8, 2018, and requiring public notice. On October 5, 2018, DEP filed its affidavits of publication indicating that the Company had provided notice in newspapers of general circulation as required by the Commission's September 11, 2018 order. On October 16, 2018, the Company filed additional affidavits of publication that it had been unable to obtain earlier due to Hurricane Florence.

On September 12, 2018, DEP filed the rebuttal testimony and exhibit of Timothy J. Duff and the rebuttal testimony of witness Evans.

On September 12, 2018, NC Justice Center filed a motion to excuse witness Neme from appearing at the September 18, 2018 hearing. On September 13, 2018, the Public Staff and DEP filed a motion to excuse their witnesses. On September 13, 2018, the Commission issued an order granting both motions.

On September 17, 2018, the Public Staff filed the supplemental testimony and exhibit of witness Maness, which incorporated the impact of the Public Staff's recommended adjustments to avoided costs to be used in the determination of the PPI and reflected the termination of the Residential Smart $aver EE Program, as well as the three adjustments made in DEP witness Miller's supplemental testimony and exhibits.

On September 18, 2018, the hearing was held as scheduled. No public witnesses appeared at the hearing.

On September 21, 2017, DEP filed the Affidavit of witness Evans authenticating Supplemental Evans Exhibit 9.

On October 8, 2018, the additional public hearing was held as scheduled. No public witnesses appeared at the hearing.

On October 18, 2018, the Public Staff filed a letter stating it had completed its review of DEP's 2017 DSM/EE program costs and had found no exceptions.

On October 18, 2018, DEP filed a proposed order, NC Justice Center filed a brief, NCSEA filed post-hearing comments, and the Public Staff filed a proposed order.

Cost Recovery Mechanism

On June 15, 2009, in Docket No. E-2, Sub 931, the Commission issued an Order Approving Agreement and Stipulation of Partial Settlement, Subject to Certain Commission-Required Modifications in DEP's first DSM/EE rider proceeding (Sub 931 Order). In the Sub 931 Order, the Commission approved, with certain modifications, an Agreement and Stipulation of Partial Settlement (Stipulation) between DEP, the Public Staff, and Wal-Mart Stores East, LP, and Sam's East, Inc., setting forth the terms and conditions for approval of DSM/EE measures and the annual DSM/EE rider proceedings pursuant to N.C. Gen. Stat. § 62-133.9 and Commission Rules R8-68 and R8-69. The Stipulation included a Cost Recovery and Incentive Mechanism for DSM and EE Programs (Original Mechanism), which was modified by the Commission in its Sub 931 Order and subsequently in its Order Granting Motions for Reconsideration in Part issued on November 25, 2009, in the same docket. The Original Mechanism as approved after reconsideration allows DEP to recover all reasonable and prudent costs incurred and utility incentives earned for adopting and implementing new DSM and EE measures in accordance with N.C. Gen. Stat. § 62-133.9, Commission Rules R8-68 and R8-69, and the additional principles set forth in the Original Mechanism.

On January 20, 2015, in Docket No. E-2, Sub 931, the Commission issued an Order Approving Revised Cost Recovery and Incentive Mechanism and Granting Waivers. In that Order, the Commission approved an agreement between DEP, the Public Staff, Natural Resources Defense Council (NRDC), and Southern Alliance for Clean Energy (SACE) proposing revisions to the Original Mechanism, generally to be effective January 1, 2016 (Revised Mechanism). The Revised Mechanism allows DEP to recover all reasonable and prudent costs incurred and utility incentives earned for adopting and implementing new DSM and EE measures in accordance with N.C. Gen. Stat. § 62-133.9, Commission Rules R8-68 and R8-69, and the additional principles set forth in the Revised Mechanism.

On November 27, 2017, in Docket No. E-2, Sub 1145 (Sub 1145), the Commission issued its Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice (Sub 1145 Order), in which it approved the agreement to revise certain provisions of the Revised Mechanism reached by the Company and the Public Staff. The Revised Mechanism, as revised by the Sub 1145 Order, is set forth in Maness Exhibit I and referred to herein as the "Mechanism."

In the present proceeding, based upon DEP's verified Application, the parties' testimony and exhibits received into evidence, and the record as a whole, the Commission makes the following:

ELECTRIC -- RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

FINDINGS OF FACT

1. DEP is a duly organized limited liability company existing under the laws of the State of North Carolina, is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North and South Carolina, and is subject to the jurisdiction of the Commission as a public utility. DEP is lawfully before this Commission based upon its Application filed pursuant to N.C. Gen. Stat. § 62-133.9 and Commission Rule R8-69.

2. The test period for purposes of this proceeding extends from January 1, 2017 through December 31, 2017.

3. The rate period for purposes of this proceeding extends from January 1, 2019 through December 31, 2019.

4. DEP has requested approval for the recovery of costs, and utility incentives where applicable, related to the following DSM/EE programs:

Residential
- Appliance Recycling
- EE Education Program
- Multi-Family EE
- My Home Energy Report (MyHER)
- Neighborhood Energy Saver (Low-Income)
- Smart $aver EE Program (formerly, Home Energy Improvement Program)
- New Construction
- EnergyWise (Load Control)
- Save Energy and Water Kit
- Energy Assessment

Non-Residential
- Smart $aver Energy Efficient Products and Assessments (formerly, EE for Business)
- Smart $aver Performance Incentive Program
- Small Business Energy Saver
- Commercial, Industrial, and Governmental (CIG) Demand Response Automation
- EnergyWise for Business

Residential and Non-Residential
- DSDR
- EE Lighting

These programs are eligible for cost and utility incentive recovery, where applicable.

5. For purposes of inclusion in this DSM/EE rider the Company's portfolio of DSM and EE programs is cost-effective.

6. The MyHER and Non-Residential Smart $aver Performance Incentive Programs do not require additional scrutiny at this time. However, if the programs do not project cost-effectiveness for future vintages, pursuant to Paragraph 22B of the Mechanism, the Company should provide a discussion of the actions being taken to maintain or improve cost-effectiveness, or alternatively, its plans to terminate the program in its next DSM/EE rider proceeding.

7. The Residential Smart $aver EE Program should not be terminated at this time. DEP should propose modifications to this program not later than December 31, 2018, with the goal of restoring the Total Resource Cost test result to 1.00 or greater. DEP should include a discussion of the impact of these modifications and other actions it has taken to improve cost-effectiveness in its next year's DSM/EE rider proceeding.

8. The evaluation, measurement, and verification (EM&V) reports filed as Evans Exhibits A, B, C, D, E, F, G, H, and K are acceptable for purposes of this proceeding and should be considered complete for purposes of calculating program impacts. DEP has appropriately incorporated the results of these EM&V reports into the DSM/EE rider calculations.

9. Acceptance of the EM&V report for the MyHER Program (Evans Exhibit I) should be postponed and addressed in next year's proceeding pending completion of the Public Staff's review.

10. The EM&V recommendations contained in the testimony of Public Staff witness Williamson are appropriate for inclusion in future EM&V reports for the applicable EE programs, when feasible and not cost prohibitive, including certain program vintages that remain to be verified and trued up.

11. The Company has complied with the Commission's requirement that DEP monitor the changes in annual ratios of allocations between non-DSDR and DSDR equipment and report the degree of change in its annual DSM/EE rider filing. No change in the allocation ratio applicable to capacitors was necessary for 2018. The allocation ratio applied to regulators was elevated from 77.79 percent to 79.45 percent for 2018. Annual review of the allocation ratios should continue, should be reported to the Public Staff each year, and any changes should be addressed in future rider proceedings.

12. It is inappropriate to calculate the avoided capacity cost benefits for purposes of the PPI and cost-effectiveness of the Company's DSM/EE programs under the assumption that capacity avoided prior to year 2022 be assigned a zero dollar value. The Public Staff's recommendation of such, and the corresponding reduction to the Company's Vintage 2019 PPI, should not be accepted.

13. In its direct testimony and exhibits, DEP requested the recovery of NLR in the amount of $40,178,116 and PPI in the amount of $21,846,452 through the EMF component of the total DSM/EE rider, and NLR of $32,348,840 and PPI of $25,997,556 for recovery in the forward-looking, or prospective component of the total rider. As a result of additional analysis performed by DEP and discussions with the Public Staff during the course of the proceeding, in its Supplemental Filing, the Company corrected its EMF NLR amount to $40,144,647 and the

EMF PPI amount to $21,798,731. The Company also corrected its prospective NLR amount to $31,947,155, as reflected in its Supplemental Filing. DEP's proposed recovery of NLR and PPI, as adjusted by the Supplemental Filing, is consistent with the Mechanism and is appropriate, subject to further review to the extent allowed in the Mechanism.

14. For purposes of the DSM/EE rider to be set in this proceeding and subject to review in DEP's future DSM/EE rider proceedings, the reasonable and appropriate estimate of the Company's North Carolina retail DSM/EE program rate period amounts, consisting of its amortized operations and maintenance (O&M) costs, depreciation, capital costs, taxes, amortized incremental administrative and general (A&G) costs, carrying charges, NLR, and PPI, is $175,770,263, and this is the appropriate amount to use to develop the forward-looking DSM/EE revenue requirement. This amount is the total of the $176,171,948 proposed in DEP's initial filing and the total adjustment of $(401,685) reflected in DEP's Supplemental Filing.

15. For purposes of the EMF component of its DSM/EE rider, DEP's reasonable and prudent North Carolina retail test period costs and incentives, consisting of its amortized O&M costs, capital costs, taxes, amortized incremental A&G costs, carrying charges, NLR, and PPI, are $168,007,613. This amount is the total of the $168,088,803 proposed in DEP's initial filing and the total EMF adjustment of $(81,190) reflected in DEP's Supplemental Filing. The reasonable and appropriate amount of test period DSM/EE rider revenues and miscellaneous adjustments to take into consideration in determining the test period DSM/EE under- or over-recovery is $157,320,600. Therefore, the test period revenue requirement, minus the test period revenues collected and miscellaneous adjustments, leaves $10,687,013 as the test period under-collection that is appropriate to use as the DSM/EE EMF revenue requirement in this proceeding.

16. After assignment or allocation to customer classes in accordance with N.C. Gen. Stat. § 62-133.9, Commission Rule R8-69, and the Commission orders in Docket No. E-2, Sub 931, the revenue requirements for each rate class, excluding the North Carolina Regulatory Fee (NCRF), are as follows:

DSM/EE PROSPECTIVE COMPONENT:	
Residential	$100,657,479
General Service EE	68,669,252
General Service DSM	6,086,071
Lighting	357,461
Total	$175,770,263
DSM/EE EMF:	
Residential	$ 494,880
General Service EE	11,979,271
General Service DSM	(1,790,030)
Lighting	2,892
Total	$10,687,013

17. The appropriate and reasonable North Carolina retail class level kilowatt-hour (kWh) sales for use in determining the DSM/EE and DSM/EE EMF billing factors in this proceeding are:

Rate Class	kWh Sales
Residential	15,740,238,953
General Service EE	9,852,771,378
General Service DSM	9,737,467,991
Lighting	361,265,217

18. The appropriate DSM/EE EMF billing factors, excluding NCRF, are: 0.003 cents per kWh for the Residential class; 0.122 cents per kWh for the EE component of the General Service classes; (0.018) cents per kWh for the DSM component of the General Service classes, and 0.001 cents per kWh for the Lighting class. These DSM/EE EMF billing factors do not change when the NCRF is included.

19. The appropriate forward-looking DSM/EE rates to be charged by DEP during the rate period, excluding NCRF, are: 0.640 cents per kWh for the Residential class; 0.697 cents per kWh for the EE component of the General Service classes; 0.063 cents per kWh for the DSM component of the General Service classes; and 0.099 cents per kWh for the Lighting class. The appropriate forward-looking DSM/EE rates to be charged by DEP during the rate period, including NCRF, are: 0.641 cents per kWh for the Residential class; 0.698 cents per kWh for the EE component of the General Service classes; 0.063 cents per kWh for the DSM component of the General Service classes; and 0.099 cents per kWh for the Lighting class.

20. DEP should leverage its collaborative stakeholder meetings (Collaborative) to discuss the EM&V issues and program design issues raised in the testimony of NC Justice Center witness Neme and report the results of those discussions in the Company's 2019 DSM/EE rider filing.

21. Beginning in 2019, the Company should increase the frequency of the Collaborative meetings so that the combined DEP/Duke Energy Carolinas, LLC (DEC) Collaborative meets every two months.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding of fact, which is supported by DEP's Application, is essentially informational, procedural, and jurisdictional in nature and is uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 2-3

No party opposed DEP's proposed rate period and test period. The rate period and test period proposed by DEP are consistent with the Mechanism approved by the Commission. The proposed rate period and test period are reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence for this finding of fact can be found in DEP's application, the testimony and exhibits of DEP witnesses Miller and Evans, the testimony of Public Staff witness Williamson, and various Commission orders in program approval dockets.

DEP witness Miller's testimony shows the portfolio of DSM/EE programs that is associated with the Company's request for approval of this rider. The direct testimony of DEP witness Evans lists the DSM/EE programs for which the Company is requesting cost recovery, and incentives where applicable, in this proceeding. Those programs are:

Residential

- Appliance Recycling
- EE Education Program
- Multi-Family EE
- MyHER
- Neighborhood Energy Saver (Low-Income)
- Smart $aver EE Program (formerly, Home Energy Improvement Program)
- New Construction
- EnergyWise (Load Control)
- Save Energy and Water Kit
- Energy Assessment

Non-Residential

- Smart $aver Energy Efficient Products and Assessments (formerly, EE for Business)
- Smart $aver Performance Incentive Program
- Small Business Energy Saver
- CIG Demand Response Automation
- EnergyWise for Business

Residential and Non-Residential

- DSDR
- EE Lighting

In his testimony, Public Staff witness Williamson also listed the DSM/EE programs for which the Company seeks cost recovery and noted that each of these programs has received approval as a new DSM or EE program and is eligible for cost recovery in this proceeding under N.C. Gen. Stat. § 62-133.9.

Thus, the Commission finds and concludes that each of the programs listed by witnesses Evans and Williamson has received Commission approval as a new DSM or EE program and is, therefore, eligible for cost recovery in this proceeding under N.C. Gen. Stat. § 62-133.9.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-7

The evidence for these findings can be found in the testimony and exhibits of Company witness Evans, Public Staff witness Williamson, and NC Justice Center witness Neme.

DEP witness Evans testified that the Company reviewed the portfolio of DSM/EE programs and performed prospective analyses of each of its programs and the aggregate portfolio for the Vintage 2019 period, the results of which are incorporated in Evans Exhibit No. 7. He noted that the Company's aggregate portfolio continues to project cost-effectiveness. However, DEP's calculations indicate that that the following programs do not pass the Total Resource Cost test (TRC) threshold of 1.00: Residential Smart $aver (TRC of 0.57); My Home Energy Report (TRC of 0.96); and Non-Residential Smart $aver Performance Incentive (TRC of 0.92).

Public Staff witness Williamson stated in his testimony that he reviewed DEP's calculations of cost-effectiveness under each of the four standard cost-effectiveness tests – the Utility Cost Test (UCT), TRC, Participant, and Ratepayer Impact Measure (RIM) tests. The Public Staff also compared the cost-effectiveness test results in previous DSM/EE proceedings to the current filing and developed a trend of cost-effectiveness that serves as the basis for the Public Staff's recommendation of whether a program should be terminated. Witness Williamson testified that while many programs continue to be cost-effective, the TRC scores as filed by the Company for all programs have decreased since the 2017 DSM/EE rider proceeding, mainly due to changes in avoided costs, but also due to updated EM&V and program participation.

Witness Williamson explained that the Public Staff does not agree with the avoided capacity rates used by the Company in its calculations of cost-effectiveness filed in this proceeding. Under the Public Staff's interpretation, the avoided capacity rates would reflect zero avoided capacity values in years prior to the identified need for new capacity in the underlying Integrated Resource Plan (IRP) that serves as the basis for the avoided capacity rate calculations.

As reflected in Evans Exhibit 7, under DEP's calculations of cost-effectiveness, the Residential Smart $aver EE Program, MyHER Program, and Non-Residential Smart $aver Performance Incentive Program are not projected to be cost-effective for Vintage 2019 under the TRC test. Under the Public Staff's methodology (i.e., applying zero capacity value for years prior to 2022), the Residential New Construction, EE for Business, and EnergyWise for Business programs would also not be cost-effective under the TRC test for Vintage 2019.

Witness Williamson recommended that pursuant to the Mechanism, the Company should provide a discussion in its filing for next year's DSM/EE rider proceeding on the actions being taken to maintain or improve the cost-effectiveness of the MyHER and the Non-Residential Smart $aver Performance Incentive Programs. Under Paragraph 22 and Paragraphs 22A-D of the Mechanism, the Company is directed to take certain actions for programs that are not projected to be cost-effective. According to Paragraph 22B-22D of the Mechanism, if a program demonstrates a prospective TRC score of less than 1.0 in a DSM/EE rider proceeding, the Company should provide a discussion of the actions being taken to maintain or improve the program's cost-effectiveness. If a program demonstrates a prospective TRC score of less than 1.00 in a third

DSM/EE rider proceeding, the Company will terminate the program at the end of the year following the DSM/EE rider order, unless otherwise ordered by the Commission.

DEP witness Evans in his rebuttal testimony notes that the TRC score for the MyHER Program is 0.96, and given how close the program is to being cost-effective, Paragraph 22B of the Mechanism should not be applicable. In his rebuttal testimony, he also notes that the Non-Residential Smart $aver Performance Incentive Program should not be subject to the scrutiny of Paragraph 22B because it has only been in place a short period of time, and it is anticipated to be cost-effective.

NC Justice Center witness Neme testified that DEP's DSM/EE portfolio is very cost-effective, demonstrating that DSM/EE programs are a least cost resource for meeting consumers' electricity needs. Based on DEP's estimated UCT benefit-cost ratio, he stated that for every dollar that DEP spends on its programs, it is eliminating the need to spend $2.63 on new power plants, the fuel to run those power plants, new power lines, and other investments otherwise needed to supply electricity to homes and businesses. DEP's analysis also suggests that the programs are very cost-effective under the TRC test, with a benefit cost-ratio of approximately 2.1 to 1.

As a whole, the Commission concludes that DEP's portfolio of DSM and EE programs is cost-effective and eligible for inclusion in the Company's DSM/EE rider. The Commission makes specific findings and conclusions as to the individual programs that DEP and/or the Public Staff have identified as not being cost-effective below.

Residential New Construction, EE for Business, and EnergyWise for Business

Witness Williamson testified that DEP's EnergyWise for Business Program is a DSM program that draws the majority of its avoided cost benefits from capacity and transmission and distribution (T&D) reductions. He acknowledged that using the Company's application of avoided capacity costs, this program is cost-effective under the TRC test. However, when using the Public Staff's methodology, this program is no longer cost-effective. Thus, according to witness Williamson, pursuant to Paragraph 22B of the Mechanism, the Company should provide a discussion of the actions being taken to maintain or improve cost-effectiveness, or alternatively, its plans to terminate the program. He recommended further that pursuant to Paragraph 22C of the Mechanism, if this program shows a prospective TRC of less than 1.00 in next year's DSM/EE rider proceeding, the Company should include a discussion of what actions it has taken to improve cost-effectiveness.

Like EnergyWise for Business, the Residential New Construction and EE for Business programs are cost-effective under the TRC test using the Company's application of avoided capacity costs, but drop below 1.00 after incorporating zeros for the value of calculating avoided costs pursuant to the Public Staff's methodology. As a result, witness Williamson recommended that, pursuant to Paragraph 22B of the Mechanism, the Company should provide a discussion of the actions being taken to maintain or improve cost-effectiveness, or alternatively, its plans to terminate the program.

In his rebuttal testimony, witness Evans indicated that the Company does not agree with the application of zero avoided capacity cost values proposed by the Public Staff for the determination of program cost-effectiveness. He reiterated that while use of the Public Staff's proposed zero avoided capacity cost values would render the EnergyWise for Business, EE for Business, and Residential New Construction programs non-cost-effective, these programs are considered to be cost-effective under the avoided cost rates applied by the Company. He concluded that because these programs are cost-effective under the TRC test using the Company's methodology, Paragraph 22B of the Mechanism does not apply. He added that it is important to recognize that these programs constitute a significant portion of the Company's DSM/EE portfolio, which demonstrates the impact that the Public Staff's position on avoided costs could have on the Company's portfolio.

In Docket No. E-7, Sub 1164, Duke Energy Carolinas, LLC's (DEC's) most recent DSM/EE Rider proceeding, the Commission concluded that it was inappropriate to calculate the avoided capacity cost benefits for purposes of the PPI and cost-effectiveness of the DEC's DSM/EE programs under the assumption that capacity avoided prior to year 2023 be assigned a zero dollar value. As a result, the Commission held in its order dated September 11, 2018 (DEC Order), that the Public Staff's recommendation otherwise, the same argument the Public Staff is making here, should be rejected. For the reasons stated in the DEC Order, the Commission declines to accept the Public Staff's position that capacity avoided by DEP prior to year 2023 be assigned a zero dollar value.

The parties note that the EnergyWise for Business, EE for Business, and Residential New Construction programs are cost-effective under the TRC test using DEP's calculation of avoided capacity costs. Therefore, the Commission finds that these programs are cost-effective, and no further action is required by the Company.

<u>MyHER Program</u>

Witness Williamson recommended that the Company be required to provide a discussion in the next proceeding on the actions being taken to maintain or improve cost-effectiveness of the MyHER program, or alternatively, its plans to terminate this program, under Paragraph 22B of the Mechanism.

Witness Evans testified that the Company's EM&V for the MyHER Program indicates a TRC result of 0.96, which is very close to 1.0. He noted that there has only been a single EM&V study performed on the MyHER Program and that this single program constitutes a significant portion of the Company's portfolio. He explained that this is merely a short-term issue that will resolve itself over time. Witness Evans testified that the program is still relatively young (launched in March 2015) and was evaluated shortly after its launch (evaluation period of calendar year 2016). Witness Evans stated that based on the MyHER results the Company has experienced in other jurisdictions where the program has been in the market longer (including DEC), the Company believes that the savings realized by participants will increase as customer engagement becomes more established. In addition, witness Evans stated that the Company continues to work with the program vendor to identify potential cost savings for the program. Given the closeness of the applicable cost-effectiveness test to 1.00 and the importance of the program, he testified that he would not recommend that MyHER fall under the provisions of Paragraph 22B of the Mechanism at this time.

Non-Residential Smart $aver Performance Incentive Program

Evans Exhibit 7 reflects the forecasted 2019 TRC score for the Non-Residential Smart $aver Performance Incentive Program is 0.92, and the UCT score is 3.75. DEP Witness Evans pointed out that these scores are significantly greater than the 0.40 TRC and 0.54 UCT scores submitted in the Company's 2017 cost recovery request. He noted that while the 0.92 TRC score may be viewed as slightly less than optimal in isolation, this program encompasses energy saving measures related to new technologies, unknown building conditions and system constraints, as well as uncertain operating circumstances, occupancy, or production schedules. He noted that as such, energy savings are difficult to project with any level of accuracy and that due to the scope of projects envisioned, the Company also believes that the program could impact a customer's decision to opt into the EE portion of the rider. Witness Evans further testified that if this program were no longer offered as part of the Company's EE portfolio, additional customers may elect to opt out as a result. Witness Evans testified that the program also limits the prospects of overcompensating participants at the expense of other customers, or undercompensating participants for their EE improvements. He emphasized that the Company believes that this program is an important element of its non-residential portfolio of programs and that its cost-effectiveness results will continue to improve as more customers become familiar with it and participation increases.

Witness Williamson testified that the Non-Residential Smart $aver Performance Incentive Program was launched in January 2017. He indicated that though this is the second year that the program has not been cost-effective, the Public Staff prefers to give new programs a year to get established before directing the Company to take action to improve cost-effectiveness. He then recommended that the Company be required to provide a discussion in the next proceeding on the actions being taken to maintain or improve cost-effectiveness of the Non-Residential Smart $aver Performance Incentive Program, or alternatively, its plans to terminate this program, under Paragraph 22B of the Mechanism.

In his rebuttal testimony, witness Evans reiterated that the program was intended to encompass large EE-related projects with uncertainty relative to their performance (e.g., projects that employ new technologies). He explained that related program incentives are provided in installments based on actual savings. As a result, participants are properly incentivized for their EE-related investments, and other customers are shielded from the impacts of overstated performance. He also indicated that very few projects are appropriate for participation in the program. The 0.92 TRC test score reflected in Evans Exhibit 7 was based upon participation forecasts and costs used in the Company's 2016 program filing. During 2017, only five projects were involved. Currently, there are seventy-four projects underway in the DEP service territory. Witness Evans testified that the Company's estimated TRC score for this program, based on these and other projects under review, should exceed 1.50. Therefore, he testified that the Company does not believe that this program requires additional scrutiny at this time, due to both the short time it has been in place and its anticipated cost-effectiveness results.

Based on the evidence presented above, and in particular the short time each program has been in place and the anticipated cost-effectiveness results, the Commission concludes that the MyHER and Non-Residential Smart $aver Performance Incentive programs do not require additional scrutiny at this time. However, if the programs to not project cost-effectiveness for future vintages, pursuant to Paragraph 22B of the Mechanism, the Company should provide a discussion of the actions being taken to maintain or improve cost-effectiveness, or alternatively, its plans to terminate the program in its next DSM/EE rider proceeding.

Residential Smart $aver EE Program

Witness Evans testified that despite several modifications, the Residential Smart $aver EE Program (formerly, HEIP) continues to struggle to maintain cost-effectiveness. More specifically, he explained that during 2016 and 2017, the Company made several changes to the program to address the erosion in the program's cost-effectiveness caused by advancement in efficiency standards and the associated lower incremental savings associated with exceeding the new standards. These program changes, which included redesign of the program to include a referral channel that reduced program costs, proved successful in returning the program to cost-effectiveness in 2017 and 2018. Unfortunately, with the application of the new lower avoided costs in 2019, the program is again projecting to no longer be cost-effective. According to witness Evans, the Company is actively working to evaluate additional programmatic changes, such as the Public Staff's recommendation to transition to referral channel measures that would offset the decline in avoided costs and make the program cost-effective in 2019 and beyond.

Witness Williamson testified that the Residential Smart $aver EE program has struggled to achieve cost-effectiveness for several years due to: (1) higher efficiency standards mandated by the federal government that have increased baselines against which savings impacts have been measured; and (2) the need for large participant incentives to overcome the upfront out-of-pocket costs to participants. He noted that DEP has consistently advocated the need to offer a residential HVAC replacement program. Because HVAC is one of the largest energy-consuming users in homes, Witness Williamson agreed that a well-designed, cost-effective program that encourages adoption of higher efficiency HVAC equipment is fundamental for any utility EE portfolio. He noted that DEP has also indicated the importance of maintaining its trade ally network. Witness Williamson agreed that it is desirable to maintain a good vendor network that provides customers with accurate, reliable information on HVAC energy consumption and other assistance. Nevertheless, he expressed concern that ratepayers should not be required to pay for a program that is not cost-effective, especially when cost-effectiveness projections continue on a downward trend.

Witness Williams testified that in Docket No. E-2, Sub 114 (Sub 1145), DEP's 2017 DSM/EE Rider proceeding, the Commission's Order stated that "if the Commission-approved modifications do not maintain or improve the program's cost-effectiveness by the next DSM/EE rider proceeding, the program should be terminated at the end of 2018." Because the Residential Smart $aver EE Program's performance has not improved, Witness Williamson recommended that the program be closed at the end of 2018. Consistent with this recommendation, Public Staff Witness Maness concluded that all associated Vintage 2019 program costs, NLR, and PPI should be removed from the calculating billing factors.

Witness Neme encouraged the Company to focus on promoting longer-lived major measures, such as those included in the Residential Smart $aver EE Program. He suggested that the Company make efforts to increase participation in rebate offers for high-efficiency heat pumps, central air conditioners, heat pump water heaters, pool pumps, attic insulation, air sealing, and duct sealing. He stated that there should be significant savings potential from these measures as they address the largest electricity end-uses in homes.

In his rebuttal testimony, witness Evans responded to witness Williamson's recommendation that the Residential Smart $aver Program be terminated. He testified that the Company believes that terminating the only program that offers assistance for making the largest single energy user in the home, a customer's HVAC system, more energy efficient does not seem reasonable, especially when the decision to make said investment only comes around once every fifteen years. He also noted that the recommended termination of the program does not take into consideration the Company's relationships with HVAC contractors. According to witness Evans, the proposed termination will likely erode trust and engagement with these valuable "trade allies," making it difficult to offer similar types of programs that would require trade ally support in the future.

Witness Evans explained that in the past, when the program's cost-effectiveness has struggled due to efficiency standard changes, the Company has demonstrated the ability to effectively modify the program to restore cost-effectiveness and should have the opportunity to attempt to restore to the cost-effectiveness of the program that was eroded by reduction in avoided costs. He indicated that Company is currently investigating several opportunities to increase the cost-effectiveness of the program, including the following:

1. While the Company does have some concerns with respect to the Public Staff's recommendation to move the program to an all-referral structure, DEP is not opposed to adopting this proposal so long as the Commission deems it appropriate. However, in lieu of moving to a referral only approach, the Company's program management team has developed a number of potential revisions to the referral program that will improve cost-effectiveness and lead to a more gradual transition to a referral only approach. The Company believes that these modifications would result in improving the program and the cost-effectiveness tests referenced in Witness Williamson's testimony;

2. The Company has been reevaluating and updating studies of the incremental costs actually being paid by customers to adopt higher efficiency equipment. This work will ensure that the Company's cost-effectiveness analysis is consistent with the current market conditions and reflects the changes in equipment pricing that occur as the new higher efficiency standards have been in place for a longer period of time. The Company believes that such information could lead to improvements in the program's TRC scores; and

3. The Company's program management team has been working with the third-party vendor used in program administration (payment processing) to further reduce program costs and increase the TRC score. (*Id.* at 80-81.)

Witness Evans testified that the Company is sure that the combination of these actions will restore cost-effectiveness and that shutting down the current operations without an appropriate time frame for planning and adjustment is not the best answer for its customers.

The Commission agrees with witnesses Evans, Neme, and Williamson that a residential HVAC program is an important program for an electric utility to offer as part of its DSM/EE portfolio. All three witnesses testified that the HVAC is one of the largest – if not, the largest – energy-consuming appliances in the home. In addition, as noted by witnesses Neme, the long measure life of an HVAC unit makes it particularly important to maintain this program as part of the Company's portfolio. A rebate for a high-efficiency HVAC unit could lead to savings for many years to come.

Both witnesses Evans and Williamson also recognize that DEP's relationship with its trade ally network – i.e., the HVAC contractors that service the HVAC equipment of participants in the Residential Smart $aver EE Program – is important to maintaining a viable HVAC program. The Commission agrees with witness Evans that a termination of the program would place those valuable relationships at risk, which could jeopardize the Company's ability to offer an HVAC program in the future. Accordingly, the Commission finds and concludes that the Residential Smart $aver EE Program should not be terminated at this time. That said, the Commission is mindful of the Public Staff's concerns that ratepayers should not pay for programs that are not cost-effective. Based on the Company's persistent efforts to maintain the viability of the program through program modifications, as well as the negative impact on the Company's PPI if the program continues to struggle to maintain cost-effectiveness, the Commission is persuaded that DEP is highly motivated to continue to find ways to improve cost-effectiveness. The Commission is hopeful that the possible improvements outlined by witness Evans will improve cost-effectiveness. Thus, the Commission directs the Company (1) to propose modifications to this program no later than December 31, 2018, with the goal of restoring the TRC score to 1.00 or greater, and (2) to include a discussion of the impact those modifications and other actions it has taken to improve cost-effectiveness in next year's DSM/EE rider proceeding. However, if DEP cannot demonstrate cost-effectiveness of this program by its next DSM/EE rider proceeding, the Commission may order the program closed as of December 31, 2019.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 8-10

The evidence for these findings of fact can be found in the testimony and exhibits of DEP witness Evans and the testimony of Public Staff witness Williamson.

DEP witness Evans testified regarding the EM&V process, activities, and results presented in this proceeding. He explained that the EMF component of the Company's DSM/EE rider incorporates actual customer participation and evaluated load impacts determined through EM&V and applied pursuant to the Mechanism. In addition, actual participation and evaluated load impacts are used prospectively to update estimated NLR. In this proceeding, the Company submitted, as exhibits to witness Evans' testimony, detailed completed EM&V reports or updates for the following programs:

- CIG Demand Response Automation – 2016 (Evans Exhibit A)
- EE Education Program – 2015 & 2016 (Evans Exhibit B)
- EnergyWise Home Demand Response Program – Summer 2016 (Evans Exhibit C)
- EnergyWise Home Demand Response Program – Winter 2016 & 2017 (Evans Exhibit D)
- Multi-Family EE Program – 2015 & 2016 (Evans Exhibit E)
- Non-Residential Smart $aver Program (Prescriptive) – 2016 & 2017 (Evans Exhibit F)
- EnergyWise for Business Program – 2016 (Evans Exhibit G)
- EE Lighting Program – 2016 & 2017 (Evans Exhibit H)
- MyHER Program – 2016 (Evans Exhibit I)
- Small Business Energy Saver Program – 2015 & 2016 (Evans Exhibit J)
- Save Energy and Water Kit Program – 2016 (Evans Exhibit K)

In his testimony, Public Staff witness Williamson testified that with respect to program vintages for which EM&V reports were filed in this proceeding, he does not recommend any adjustment to the impacts at this time. He also testified that he had confirmed through sampling that the changes to program impacts and participation were appropriately incorporated into the rider calculations for each DSM and EE program, as well as the actual participation and impacts calculated with the EM&V data. Witness Williamson stated his belief that DEP was appropriately incorporating the results of EM&V into the DSM/EE rider calculations consistent with Commission orders and the Mechanism.

In addition, witness Williamson stated that DEP had adopted his EM&V-related recommendations made in the 2017 DSM/EE rider proceeding, Docket No. E-2, Sub 1145, to the extent those recommendations are applicable to the EM&V reports filed in this proceeding. He also provided recommendations concerning the content of future EM&V studies for particular EE programs, noting that DEP's implementation of these recommendations would be subject to the consideration of whether the recommendation would be cost prohibitive.

Witness Williamson also provided recommendations concerning the content of future EM&V studies for the Company's EE Lighting Program, noting that DEP's implementation of these recommendations would be subject to the consideration of whether the recommendation would be cost prohibitive. Public Staff witness Williamson recommended that:

1. The program evaluator should include the basis for the selected weighting methodology (weightings based on bulb sales, measure savings, or other metric) when assessing program savings. The program evaluator should also indicate the other weighting methodologies that were considered, why they were rejected, and why the selected methodology is preferable;

2. The program evaluator should provide further clarity into the sales of incentivized bulbs at dollar/discount stores to determine the income levels of customers purchasing these bulbs; and

3. The program evaluator should update its study on the percentage of bulb sales to residential and non-residential customers.

Regarding the EM&V report for the MyHER Program, Evans Exhibit I, witness Williamson stated that while the Public Staff has confidence in the methodology applied to complete this evaluation and believes that the overall savings appear to be reasonable and in line with the findings of other similar evaluations of residential behavioral savings in the United States, it has not finalized its review of the overall findings and savings estimates put forth in the evaluation report at this time. Witness Williamson recommended postponing acceptance of the results of the MyHER program until the Public Staff conducts further review and offers recommendations in the next DSM/EE rider proceeding.

Witness Williamson concluded that, with the exception of the MyHER Program EM&V Report (Evans Exhibit I), the EM&V of the vintages of the measures covered by the remaining reports filed in this proceeding should be considered complete. In addition, he recommended that the two reports from the Sub 1145 proceeding, Small Business Energy Saver Program EM&V Report, and the Multi-Family EE Program EM&V Report, (Evans Exhibits D and E, respectively, filed in the Sub 1145 proceeding) be considered complete for the purposes of calculating program impacts in this proceeding.

In his rebuttal testimony, DEP Witness Evans raised concerns regarding two of the recommendations regarding the future evaluations of the EE Lighting Program. Witness Evans noted that the most reliable methods to determine both the income level of the purchasers of bulbs at dollar/discount stores and to update the percentage of bulb sales to residential and non-residential customers would require in-store intercepts. However, he pointed out that the EM&V evaluators have had problems in the past gaining access to stores to conduct the in-store intercepts.

With the exception of those EM&V-related recommendations made by Public Staff witness Williamson for revisions to Evans Exhibits H and I, no party contested the EM&V information submitted by the Company. The Commission therefore finds that the EM&V reports filed as Evans Exhibits A, B, C, D, E, F, G, H, J, and K are acceptable for purposes of this proceeding and should be considered complete for purposes of calculating program impacts; that the EM&V reports for Small Business Energy Saver Program (Evans Exhibit D) and the Multi-Family EE Program (Evans Exhibit D) from the 1145 proceeding should be considered complete; acceptance of the EM&V Report for the MyHER program should be postponed until the Public Staff conducts further review and offers recommendations in the next DSM/EE rider proceeding; and the EM&V recommendations concerning future EM&V reports contained in the testimony of Public Staff witness Williamson should be approved and applied in future EM&V reports for the applicable EE programs, when feasible and not cost prohibitive.

Based upon the testimony and evidence cited above, the Commission finds the net energy and capacity savings derived from the EM&V to be reasonable and appropriate. Further, the Commission concludes that DEP is appropriately incorporating the results of EM&V into the DSM/EE rider calculations.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence for this finding of fact can be found in the testimony of DEP witness Evans.

The Commission's Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice, issued on November 16, 2015 in Docket No. E-2, Sub 1070, provided that DEP shall file all changes in annual ratios of allocations between non-DSDR and DSDR equipment, report the degree of change in its annual DSM/EE rider filing, and provide such changes to the Public Staff as they become available. Witness Evans informed the Commission that a review of 2016 units showed that no change in the allocation ratio applicable to capacitors was necessary for 2018. However, the allocation ratio applied to regulators was elevated from 77.79 percent to 79.45 percent for 2018. He stated that 2017 units would be reviewed, and any changes would be communicated to the Public Staff and implemented on January 1, 2019. Based on the evidence, the Commission concludes that DEP should continue to file reports of changes to its allocations between non-DSDR and DSDR equipment in future proceedings and provide the Public Staff with information on any changes to the allocation factor as they become available.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence in support of this finding can be found in the testimony and exhibits of Company witness Duff; the testimony and exhibits of Public Staff witnesses Maness, Hinton, and Williamson; and various Commission orders.

In its application, the Company included avoided capacity cost benefits in every year of the life of a measure when calculating the PPI and when calculating the cost-effectiveness of its programs. The Public Staff disagreed with the Company regarding the appropriate level of avoided costs to be used in the determination of the PPI and calculations of cost-effectiveness. The Public Staff contended that DEP is required by the Revised Mechanism and the Sub 148 Order to use zero as the input when calculating the avoided capacity values for DSM/EE until 2021, when DEP's IRP shows a capacity need. As such, the Public Staff recommended that the avoided capacity cost benefits for purposes of the PPI and cost-effectiveness of the Company's DSM/EE programs be calculated under the assumption that capacity avoided prior to year 2021 be assigned a zero dollar value.

Background

Paragraph 70 of the Revised Mechanism set out the method for determination of avoided capacity costs as follows:

> 69. For the PPI for Vintage Year 2016, the per kW avoided capacity costs used to calculate avoided cost savings shall be the avoided capacity cost rates approved by the Commission for DEP in the most recent biennial avoided cost proceeding as of the date of the filing of the 2015 DSM/EE cost and incentive recovery proceeding. The per kWh avoided energy costs shall be those

reflected in or underlying the most recently filed integrated resource plan (IRP).

70. For the PPI for Vintage Years after 2016, the presumptive per kW avoided capacity costs and per kWh avoided energy costs used to calculate avoided cost savings shall be those determined pursuant to paragraph 69 above. However, if at the time of initial estimation of the PPI for each vintage year after 2016, either (a) the Company's per kWh avoided energy costs calculated for the purposes of the Company's annual IRP or resource plan update filings have increased or decreased by 20% or more or (b) the Company's per kW avoided capacity costs reflected in the rates approved in the biennial avoided cost proceedings have increased or decreased by 15% or more, the avoided costs (both energy and capacity) will be updated for purposes of the DSM/EE rider proceeding.

The parties sometimes referred to the method for updating avoided costs under Paragraph 70 of the Revised Mechanism as the "trigger" or "ratchet" method, in that avoided costs would remain the same unless and until the specified thresholds were met – either a change in avoided energy costs of at least 20% or a change in avoided capacity costs of at least 15% – which would then trigger an update of both avoided energy and avoided capacity costs. In addition, under Paragraph 70 of the Revised Mechanism, avoided energy costs and avoided capacity costs were derived from two different sources: the annual IRP or resource plan update filings for avoided energy, and the biennial avoided cost proceedings for avoided capacity.

In DEP's 2017 DSM/EE proceeding (Sub 1145), the Public Staff and DEP discovered that they had differing interpretations as to the appropriate avoided costs to be used in calculating the 2018 DSM/EE rider pursuant to Paragraph 70 of the Revised Mechanism. The Public Staff believed that the "ratchet" that would cause avoided capacity and energy costs to be updated for purposes of the DSM/EE rider proceeding had been triggered for purposes of the PPI to be calculated for Vintage 2018. The Company maintained that the ratchet had not been triggered. Had avoided cost rates been updated in a manner consistent with the Public Staff's interpretation of Paragraph 70, the Vintage 2018 PPI would have been reduced by approximately $3.3 million.

The Company and the Public Staff eventually reached a comprehensive agreement (Sub 1145 Agreement) resolving their differences which consisted of (1) a monetary adjustment which reduced the Vintage 2018 PPI by $2.1 million; and (2) certain revisions to the Revised Mechanism, including the method by which avoided costs would be updated for purposes of the PPI and DSM/EE program cost-effectiveness. In particular, DEP and the Public Staff recommended certain changes to Paragraphs 18, 22, and 70 of the Mechanism, and the addition of new Paragraphs 22A through 22D and 70A. The Commission approved the Sub 1145 Agreement and the resulting revisions to the Revised Mechanism in the Sub 1145 Order.[1]

[1] In DEC's 2017 DSM/EE proceeding (E-7, Sub 1130, or Sub 1130), DEC and the Public Staff encountered the same disagreement over whether the avoided cost ratchet had been triggered for purposes of DEC's 2018

Paragraph 70A now governs the calculation of the PPI, and provides that:

> For the PPI for Vintage Years 2019 and afterwards, the program-specific per kW avoided capacity benefits and per kWh avoided energy benefits used for the initial estimate of the PPI and any PPI true-up will be derived from the underlying resource plan, production cost model, and cost inputs that generated the avoided capacity and avoided energy credits reflected in the most recent Commission-approved Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities as of December 31 of the year immediately preceding the date of the annual DSM/EE rider filing. However, for the calculation the underlying avoided energy credits to be used to derive the program-specific avoided energy benefits, the calculation will be based on the projected EE portfolio hourly shape, rather than the assumed 24x7 100 MW reduction typically used to represent a qualifying facility.

Paragraph 18 (which governs the calculation of cost-effectiveness for program approval filings) and Paragraph 22 (which governs continuing cost-effectiveness for existing programs) were revised to reflect the same method for determining avoided costs.[1]

Public Staff witness Williamson testified that the Public Staff believes that the Company's calculation of cost-effectiveness was not appropriately based on the avoided capacity rates approved in the Commission's October 11, 2017 order approving new avoided cost rates in Docket No. E-100, Sub 148 (Sub 148 Avoided Cost Order). The Public Staff believes that the Mechanism requires the Company to use avoided capacity rates consistent with the Sub 148 Avoided Cost Order and that the rates should reflect zero capacity value in years prior to the identified need for new capacity in the underlying IRP. Public Staff witness Williamson stated that the avoided cost methodology used for capacity payments to qualified facilities (QFs) should be the same as the methodology for calculating cost effectiveness of DSM/EE measures. Public Staff witness Maness also stated that the avoided costs benefits used to determine PPI should also be consistent with the avoided cost rates for capacity set by the Commission for QFs. He further recommended that DEP adjust its estimated Vintage Year 2019 PPI proposed in this case to bring it into compliance with Paragraph 70A of the Revised Mechanism.

DSM/EE rider. DEC and the Public Staff eventually reached a resolution (the Sub 1130 Agreement) which consisted of (1) a monetary adjustment which reduced the Vintage 2018 PPI (which in DEC's case amounted to a $6.75 million adjustment); and (2) revisions to DEC's cost recovery mechanism, including the method by which avoided costs would be updated for purposes of the PPI and DSM/EE program cost-effectiveness. The Sub 1130 Agreement and resulting revisions to DEC's cost recovery mechanism were approved by the Commission in its Order Approving DSM/EE Rider, Revising DSM/EE Mechanism, and Requiring Filing of Proposed Customer Notice, issued in Sub 1130 on August 23, 2017, prior to the Sub 1145 proceeding. The Sub 1130 Agreement and the resulting revisions to DEC's cost recovery mechanism are substantively the same as – and, in fact, are the basis of – the Sub 1145 Agreement and the resulting revisions to DEP's Revised Mechanism approved in Sub 1145.

[1] The Public Staff refers to the method for calculating avoided cost rates pursuant to revised Paragraph 18 and new Paragraphs 22A and 70A as the "PURPA method."

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

In the most recent Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities (Avoided Cost Proceeding) in Docket No. E-100, Sub 148 (Sub 148), the Commission was faced with whether certain changes to the previously-approved methods used to calculate avoided cost rates and to the current framework for implementing Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) were warranted given the amount and pace of the development of QFs, and in particular solar QFs, in North Carolina. The issue arose as to whether utilities should have to pay QFs for capacity in years in which they do not have a capacity need. Witnesses in the proceeding described significant growth in solar production in the State resulting in over-supply, operational challenges, and artificially high costs passed on to North Carolina residents, businesses, and industries. Both DEP and DEC proposed, and a number of parties, including the Public Staff, agreed, that a utility should include zeros in the calculation of capacity rates for the years in which the utility does not have a capacity need.

While the case was pending, N.C. Gen. Stat. § 62-156(b)(3) was amended by the General Assembly to provide, with respect to power sales by small power producers to public utilities:

> A future capacity need shall only be avoided in a year where the utility's most recent biennial integrated resource plan filed with the Commission pursuant to G.S. 62-110.1(c) has identified a projected capacity need to serve system load and the identified need can be met by the type of small power producer resource based upon its availability and reliability of power, other than swine or poultry waste for which a need is established consistent with G.S. 62-133.8(e) and (f).

In its Sub 148 Order, the Commission concluded that with regard to QFs that are small power producers, N.C. Gen. Stat. § 62-156(b)(3) requires that when calculating avoided capacity rates using the peaker method, it is appropriate to require a payment for capacity in years of a utility's IRP forecast period only when a capacity need is demonstrated during that period. The Commission found that providing a levelized capacity payment over the term of the standard offer contract is a reasonable means of implementing this capacity payment. The Commission also determined that this avoided capacity payment methodology is appropriate with regard to the standard offer to purchase available to QFs that are not small power producers. The Commission based this change in methodology upon the "changed economic and regulatory circumstances facing QFs and utilities" – namely, the increasing amount of solar powered QF development activity and its impact on utilities' systems and rates.

The underlying IRP for purposes of the Sub 148 proceeding – DEP's 2016 IRP – does not show a capacity need until 2022. As such, the Commission's ruling in Sub 148 results in avoided capacity rates that use a zero value for capacity for the years 2019 to 2021. However, that ruling does not apply to QFs that established a legally enforceable obligation (LEO) prior to the date the Company made its avoided cost filing in Sub 148. As a result, QFs establishing a LEO after November 15, 2016 (new QFs) receive a capacity value that is zero in years 2019 through 2021; QFs that established LEOs prior to November 15, 2016 (legacy QFs) receive a capacity value that is not zero in years 2019 through 2021.

Summary of Testimony

Public Staff witness Hinton testified that the Public Staff interprets the Sub 1145 Order and the Sub 148 Order to mean that the Company's avoided capacity rates for DSM/EE should reflect zero avoided capacity value in years prior to the identified need for new capacity in the Company's IRP. He explained that as a result of the Commission ruling in the Sub 148 Order, "new" QFs seeking to sell their energy and capacity to DEP will not be paid capacity payments until new capacity is needed in 2022, as identified in the Company's 2016 IRP.[1]

Witness Hinton pointed out that the Commission noted in the Sub 148 Order that "in addition to providing the basis for electric power purchases from QFs by a utility, the Commission determined avoided costs are utilized in, among other applications, the determination of the cost-effectiveness of DSM/EE programs and the calculation of the performance incentives for such programs..." Though he acknowledged that the focus of his testimony in DEP's 2017 DSM/EE rider proceeding (Sub 1145) was on the use of PURPA-based models to determine the appropriate avoided energy cost, witness Hinton asserted that his testimony in DEC's parallel 2017 rider proceeding (Sub 1130) linked the PURPA-based avoided capacity and energy costs to the savings and financial incentives of the Company's DSM/EE programs. As a result, he concluded that in order to be consistent with the Sub 148 Order and the Mechanism, "determinations of ongoing cost-effectiveness and utility incentives of both new DSM/EE programs and new vintages of existing DSM/EE programs starting in vintage 2019 should be based on avoided capacity rates that reflect zero avoided capacity value in years prior to the identified need for new capacity in the Company's IRP (2022)."

Witness Hinton testified that the Public Staff believes that the Company was not consistent with Sub 148 and the Mechanism in how it applied avoided capacity value with respect to its DSM/EE programs. He stated that, in assessing the ongoing cost-effectiveness of its DSM/EE programs and the appropriate level of utility incentives, the Company applied the approved avoided capacity rate in all years of the measures lives for its programs, as opposed to applying zero capacity values in years prior to the need for new capacity.

Witness Hinton noted that in response to data requests, the Company contended DSM/EE is distinct from QFs in that without DSM/EE in the IRP, there would be an immediate need for new capacity. The Company maintained that the very fact that the DSM/EE portfolio has been included in the resource plan is the reason there is not a capacity need until 2022. As such, the Company's position is that the DSM/EE within the IRP has capacity value and should receive avoided capacity benefits in all years. Witness Hinton disagreed, stating that in his opinion the utilization of the existing block of DSM/EE programs in the IRP does not justify an exception from the use of zero capacity values.

Public Staff witness Maness testified that he concurs with witness Hinton's recommendation that the avoided capacity cost benefits for purposes of the PPI and

[1] New QFs under the standard offer tariff will receive capacity payments in years prior to the utilities' first capacity need because the new QFs will receive a levelized capacity rate reflecting a lower annual payment to account for those initial years in which there are no avoidable capacity costs.

cost-effectiveness of the Company's DSM/EE programs be calculated under the assumption that capacity avoided prior to year 2022 be assigned a zero dollar value. He testified that the Company's estimated PPI calculations should be adjusted to reflect this assumption. He testified that the Public Staff asked the Company to provide a calculation of estimated avoided cost benefits related to Vintage Year 2019 under the assumption that avoided capacity kW occurring prior to year 2022 is assigned a zero dollar value. According to the Company's calculation, making this assumption reduces the estimated Vintage 2019 system-level PPI (before levelization) from $14,913,197 to $13,404,068, a decrease of $1,509,129. He also recommended that the $1,509,129 reduction in the system PPI be included in all future true-ups of the Vintage 2019 DSM/EE revenue requirement and billing factors. In his supplemental testimony, witness Maness testified that the rate period 2019 revenue requirement impact of the Public Staff's recommended adjustment to reduce the avoided costs used in the determination of the PPI to reflect a value of zero is a reduction of $488,550.[1] Witness Maness incorporated this reduction into his recommended billing factors as set forth on Maness Exhibit II.

Public Staff witness Williamson discussed the impact to the cost-effectiveness of the Company's DSM/EE portfolio that would result from applying zero capacity value for years prior to 2022, in accordance with the Public Staff's recommendation. Williamson Exhibit 3 shows the decrease in cost-effectiveness scores for each program when no capacity value is given for years that DEP's 2016 IRP does not show a capacity need. In addition to the programs that were not cost-effective under the TRC test according to the Company's calculations, DEP's Residential New Construction, EE for Business, and EnergyWise for Business programs, which are addressed in a previous section of this order would, no longer be cost-effective under the Public Staff's methodology.

DEP witness Duff provided rebuttal testimony on the issue of the appropriate avoided capacity value to be used in calculation of the PPI and cost-effectiveness. Witness Duff explained that the revisions to the Mechanism approved in Sub 1145 eliminated the Mechanism triggers to change the avoided cost rates to be used to evaluate the PPI and cost-effectiveness, and approved the current language of Paragraphs 18, 22A, and 69 of the Mechanism. He also noted that a second primary purpose of the revision was to change the source and methodology for calculating avoided energy costs from the IRP to the most recently approved avoided cost proceeding. He contended that the revisions approved in the Sub 1145 Order did not change the source of methodology. underlying the avoided capacity calculation.

Witness Duff described how, consistent with the Commission-approved revisions to DEP's DSM/EE cost recovery Mechanism, the Company derived both the avoided energy and avoided capacity using the rates approved in the Company's most recent biennial avoided cost proceeding, which in this case is Sub 148. In particular, he noted that the Company utilized the avoided capacity value calculated using the peaker method consistent with the Company's understanding of the Sub 1145 Agreement, which, in the Company's view, did not modify the approach used in past DSM/EE proceedings.

[1] Witness Maness noted that, if accepted by the Commission, the long-term impacts of this adjustment will be significantly greater, in total, because a given vintage year's PPI is typically amortized over several years into the future; the $488,550 figure represents only one of those years.

Witness Duff opined that the Company had calculated avoided capacity values consistent with Public Staff Witness Hinton's testimony in Sub 1145, and that witness Hinton had never testified that the avoided capacity rates used for existing DSM EE programs should be the same as those paid to QFs. Witness Duff further stated that during the Sub 1145 proceeding, DEP had provided the Public Staff with a projection of what the change in Vintage 2019 PPI would be under the revisions to the Mechanism if DEP's proposed avoided costs rates in Sub 148 were approved. The projection showed capacity values in each year. Witness Duff further testified that the Company agrees with Public Staff witness Hinton's testimony that the rates paid QFs are generally linked to the avoided cost rates utilized for DSM/EE. However, according to witness Duff that does not mean the rates are the same.

Witness Duff also disagreed with the Public Staff's argument that the Sub 148 Order dictates that the Company must use zero values instead of capacity values for existing DSM/EE programs. He explained how witness Hinton quoted the Sub 148 Order out of context, and that the language witness Hinton referenced does not support the Public Staff's position.

Next, witness Duff explained why DEP believes the Public Staff's approach is inappropriate and underestimates the value of the Company's DSM/EE programs. Witness Duff testified that the Public Staff's adjustment would remove the avoided capacity value of DSM/EE in the years 2019 to 2021 for purposes of evaluating cost-effectiveness and PPI, a removal of capacity value for 951 MW of DSM impacts and 128 MW of EE impacts of summer capability from DEP's portfolio of DSM/EE programs.

Witness Duff indicated that legacy DSM programs are embedded in the resource plan, and like legacy QFs with LEOs existing prior to November 15, 2016, should receive a capacity value in the 2019 to 2021 time period. He disagreed with witness Hinton's contention that the Company's existing DSM programs should be treated differently from existing QFs with regard to receiving avoided capacity value based on contract length. Witness Duff notes that witness Hinton bases his contention on the assumption that while existing QFs are under long-term contracts of up to ten years, customers who participate in DSM are under a contract for one year. First, witness Duff clarified that while residential customers do have the ability to cease participation in the residential DSM program after one year, non-residential customers who elect to participate in the Company's CIG Demand Response Automation Program agree to a contract period of five years, with automatic extensions of two years thereafter, unless terminated by either party at the end of the contract period with at least 60 days prior written notice. Second, while acknowledging that the majority of the Company's EE programs do not require the customer to sign a contract, witness Duff stated that one EE program, MyHER, is effectively in the same position as the legacy DSM programs. He noted that the MW capability provided by the MyHER EE program was created prior to the establishment of the new avoided cost rates. According to witness Duff, all that is required is the expenditure of funds to maintain the impacts, just like the Company must do to maintain the availability of the impacts from the legacy DSM programs. Like the Company's legacy DSM programs, the MyHER program impacts are also not incremental or new after November 2016. He stated that they are embedded in the resource plan, and like legacy QFs with LEOs existing prior to November 15, 2016, should receive a capacity value in the 2019 to 2021 time period.

With respect to the other EE programs (aside from MyHER), witness Duff indicated that there is a summer capacity need of 216 MW (166 MW for the winter) from the EE programs in the year 2022. He observed that, "Those familiar with the implementation of EE programs will recognize that one does not create 216 MW of EE overnight. It takes time. It takes time to build customer awareness. It takes time for equipment to wear out and be replaced or for customers to recognize that it is time to change out equipment." In addition, he noted in the Company's IRP, the EE impacts are subtracted from the load forecast. As a result, there is no reserve margin for the EE impacts.

Witness Duff testified that the very fact that DSM/EE capacity savings from existing approved programs are included in the IRP forecast is a critical part of the reason there is not a capacity need until 2022. The Company's inputs to the IRP for the cost of the DSM and EE programs include not just the implementation cost, but also the estimate of the utility's PPI, which contains a capacity value for the years 2019 through 2021. As a result, to be consistent with the underlying resource plan, including the cost inputs, one should be including the avoided capacity cost for DSM/EE for the years 2019 to 2021.

Finally, witness Duff noted that the Company believes that the Commission's ruling in the DEC Order relating to avoided costs is dispositive of the avoided cost issue in this proceeding. He stated that the relevant language in the DEC cost recovery mechanism is substantively identical to the relevant language in the DEP cost recovery mechanism; the agreement reached between the Public Staff and the Company which resulted in that language was substantively the same as that reached for DEC; and the rationale with which the Commission generally agreed in the DEC Order ("evaluating the contributions that DSM/EE measures make to a utility avoided future capacity needs to determine cost-effectiveness is inherently different than the evaluation undertaken to determine the capacity costs avoided through the purchase of the electric output from a QF") applies equally in this case. Accordingly, the Company believes that the Commission should reach the same result and decline to accept the Public Staff's downward adjustment to DEP's PPI in this docket.

In its post-hearing brief, NC Justice Center agreed with DEP's calculation of avoided capacity costs for purposes of establishing the PPI and calculating cost effectiveness. NC Justice Center contended that assigning a zero-capacity value to DEP's suite of cost-effective DSM/EE programs would discourage the Company from making investments that save ratepayers money in part because of the avoided capacity. Moreover, NC Justice Center stated that it agrees with DEP's decision to continue offering the Residential Energy $aver Program.

In its post-hearing comments, NCSEA maintained that the Commission should reject the Public Staff's position that the avoided capacity benefits used for program approval, PPI, and review of on-going cost effectiveness of DEP's DSM/EE programs should include zero capacity value in years prior to 2023.

<u>Commission Discussion</u>

Based on the foregoing, as well as the record in Sub 1145, the Commission finds and concludes that the Company's calculation of its proposed DSM/EE rider for 2019 is consistent with the language and intent of the Sub 1145 Agreement and Paragraphs 18, 22A, and 70A of the Mechanism. As witness Duff testified, the Sub 1145 Agreement was intended to eliminate the trigger method, so that avoided costs would be updated more frequently, and to change the source of avoided energy costs, so that avoided energy and avoided capacity rates for DSM/EE would be derived from the same proceeding. The revisions to Paragraphs 18, 22, and 70 resulting from the Sub 1145 Agreement did not alter the source or manner in which the avoided capacity costs are to be derived for the purpose of calculating cost-effectiveness and incentives associated with DSM/EE programs.

The Commission notes that in DEC's most recent DSM/EE rider proceeding in Docket No. E-7, Sub 1164, the Commission rejected this same argument now raised by the Public Staff, holding that "It is inappropriate to calculate the avoided capacity cost benefits for purposes of the PPI and cost-effectiveness of the Company's DSM/EE programs under the assumption that capacity avoided prior to year 2023[1] be assigned a zero dollar value. The Public Staff's recommendation of such, and the corresponding reduction to the Company's Vintage 2019 PPI, is rejected." The controlling facts in the DEC Order are essentially the same in this proceeding, and the Commission finds no reason to stray from that same conclusion.

The Commission further finds that including capacity values with respect to this issue is consistent with the public policy of the State of North Carolina. The Public Staff's position implies that DSM/EE is the first capacity resource that should be cut out of the Company's resource plan in the event DEP's IRP does not show a need for capacity. Similarly, adopting the Public Staff's zero avoided capacity value position for DSM/EE, would have the effect of removing the financial incentive for the Company to pursue certain programs in years 2019 through 2021, and would discourage the Company from developing DSM/EE programs to help customers to reduce their kW impact.

Finding that customers should not have to pay for third parties to supply generation capacity that the Company does not need – the crux of N.C. Gen. Stat. § 62-156 and the Sub 148 Order – is a different matter from encouraging customers to use less energy and capacity to decrease their bills. As the stated public policy of North Carolina, use of less energy should be encouraged and reflected in the Company's rates through "consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills."

The Commission generally agrees with the testimony of DEP witness Duff and DEP's arguments that evaluating the contributions that DSM/EE measures make to a utility's avoiding future capacity needs to determine cost-effectiveness is inherently different from the evaluation undertaken to determine the capacity costs avoided through the purchase of the electric output from a QF. In addition, the Commission is persuaded by the arguments of DEP and NC Justice Center that assigning a zero capacity value to DSM programs would under-value the contributions of those programs and send the wrong pricing signal. The Commission, therefore, declines to accept the Public Staff's downward adjustment to the Vintage 2019 PPI, and, instead, accepts the cost-effectiveness calculations performed by the Company for purposes of the DSM/EE rider at

[1] DEC's 2016 IRP does not show a capacity need until 2023.

issue in this proceeding, and approves the Company's calculation of the DSM/EE rates for Vintage 2019, as reflected in the supplemental testimony and exhibits of DEP witness Miller.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13-19

The evidence for these findings of fact can be found in the testimony and exhibits of DEP witnesses Miller and Evans and the testimony and exhibits of Public Staff witness Maness.

In her direct testimony and exhibits, DEP witness Miller calculated proposed North Carolina retail NLR in the amount of $40,178,116 and a PPI in the amount of $21,846,452 for the EMF component of the total DSM/EE rider, and North Carolina retail NLR of $32,348,840 and a PPI of $25,997,556 for the forward-looking, or prospective component of the total rider. Company witness Miller indicated that as a result of additional analysis performed by DEP and discussions with the Public Staff, the Company adjusted its NLR and PPI amounts in the Supplemental Filing. The supplemental exhibits of witness Miller included in the Supplemental Filing indicated that the EMF NLR and PPI amounts were adjusted to $40,144,647 and $21,798,731, respectively, and the prospective NLR estimate was adjusted to $31,947,155.

In her exhibits filed as part of the Supplemental Filing, DEP witness Miller calculated DEP's total North Carolina retail adjusted test period costs and utility incentives, consisting of its amortized DSM/EE O&M costs, capital costs, taxes, amortized incremental A&G costs, carrying charges, NLR, and PPI to be $168,007,613. Witness Miller's testimony and exhibits also indicated that the amount of test period DSM/EE rider revenues and miscellaneous adjustments to take into consideration in determining the test period DSM/EE under- or over-recovery is $157,320,600. Therefore, the aggregate DSM/EE under-recovery recommended by DEP for purposes of this proceeding is $10,687,013, as reflected in the Supplemental Filing.

Witness Miller also calculated DEP's estimate of its North Carolina retail DSM/EE program rate period amounts, consisting of its amortized O&M costs, depreciation, capital costs, taxes, amortized incremental A&G costs, carrying charges, NLR, and PPI, as $175,770,263.

According to the revised exhibits of DEP witness Miller as filed in the Supplemental Filing, after assignment or allocation to customer classes in accordance with N.C. Gen. Stat. § 62-133.9, Commission Rule R8-69, and the Commission orders in Docket No. E-2, Sub 931, the revenue requirements for each class, excluding NCRF, are as follows:

DSM/EE PROSPECTIVE COMPONENT:	
Residential	$100,657,479
General Service EE	68,669,252
General Service DSM	6,086,071
Lighting	357,461
Total	$175,770,263

DSM/EE EMF:

Residential	$ 494,880
General Service EE	11,979,271
General Service DSM	(1,790,030)
Lighting	2,892
Total	$10,687,013

Witness Miller's exhibits also set forth the North Carolina retail class level kWh sales that DEP believes are appropriate and reasonable for use in determining the DSM/EE and DSM/EE EMF billing factors in this proceeding. She adjusted the kWh sales to exclude estimated sales to customers who have opted out of participation in DEP's DSM/EE programs. The adjusted sales amounts are as follows: Residential class – 15,740,238,953 kWh; General Service EE class – 9,852,771,378 kWh; General Service DSM class – 9,737,467,991; and Lighting class – 361,265,217 kWh.

According to her revised exhibits filed as part of the Supplemental Filing, witness Miller calculated the DSM/EE billing factors without NCRF as follows:

DSM/EE PROSPECTIVE BILLING FACTORS (cents/kWh):

Residential	0.640
General Service EE	0.697
General Service DSM	0.063
Lighting	0.099

DSM/EE EMF BILLING FACTORS (cents/kWh):

Residential	0.003
General Service EE	0.122
General Service DSM	(0.018)
Lighting	0.001

Including the NCRF, the factors calculated by witness Miller are as follows:

DSM/EE PROSPECTIVE BILLING FACTORS (cents/kWh):

Residential	0.641
General Service EE	0.698
General Service DSM	0.063
Lighting	0.099

DSM/EE EMF BILLING FACTORS (cents/kWh):

Residential	0.003
General Service EE	0.122
General Service DSM	(0.018)
Lighting	0.001

Public Staff witness Maness indicated that the focus of the Public Staff's investigation of DEP's filing in this proceeding was whether the proposed DSM/EE rider was calculated in accordance with the Mechanism and otherwise adhered to sound ratemaking concepts and principles. The Public Staff's investigation included a review of the Company's filing and relevant prior Commission proceedings and orders, and workpapers and source documentation used by the Company to develop the proposed billing rates (including the selection and review of a sample of source documentation for test period costs included by the Company for recovery).

With the exception of the avoided costs to be used in determination of the PPI and the recommendation of the Public Staff to terminate the Residential Smart $aver EE Program, witness Maness testified that the Company has calculated its proposed prospective DSM/EE and DSM/EE EMF billing factors in a manner consistent with N.C. Gen. Stat. § 62-133.9, Commission Rule R8-69, and the Mechanism.

Company Supplemental Adjustments to Rate Calculations

Public Staff witness Maness testified that in its filing in this proceeding, the Company cut off NLR, as of the March 16, 2018, the effective date of the general rate increase approved by the Commission in Docket No. E-2, Sub 1142 (Sub 1142), associated with DSM/EE measures installed through December 31, 2016, the end of the Sub 1142 test year.[1] However, DEP did not further reduce NLR to reflect the update adjustment made in Sub 1142 to capture changes in residential per customer usage through October 31, 2017. Witness Maness testified that after discussions with the Public Staff, the Company agreed to make an adjustment to remove from residential NLR the impacts of the measures installed/implemented through October 31, 2017. He noted that the Company also indicated to the Public Staff that in calculating this adjustment related to 2017, it found that it had initially overstated the amount of residential and nonresidential NLR related to 2016 that should be removed. He stated that DEP had provided workpapers to the Public Staff that indicated that the net of the two corrections for the 2019 rate period is a reduction to

[1] This adjustment is necessitated due to paragraph 58 of the mechanism which states that: "Notwithstanding the allowance of 36 months' Net Lost Revenues associated with eligible kWh sales reductions, the kWh sales reductions that result from measurement units installed shall cease being eligible for use in calculating Net Lost Revenues as of the effective date of (a) a Commission-approved alternative recovery mechanism that accounts for the eligible Net Lost Revenues associated with eligible kWh sales reductions, or (b) the implementation of new rates approved by the Commission in a general rate case or comparable proceeding to the extent the rates set in the general rate case or comparable proceeding are set to explicitly or implicitly recover the Net Lost Revenues associated with those kWh sales reductions."

NC retail NLR of approximately $308,000[1]. He testified that the Public Staff was in the process of reviewing the workpapers and that it was his understanding that DEP would incorporate said adjustments into its supplemental filing.

Witness Maness noted in his testimony that although the test period in the Company's most recent general rate case in Sub 1142 was January 1, 2016 through December 31, 2016, the Agreement and Stipulation of Partial Settlement agreed to between the Public Staff and the Company in that proceeding included updated revenues that reflected changes in the number of customers and, for the residential class, changes in weather-normalized usage per customer through October 31, 2017.

In her supplemental testimony, witness Miller testified that the Public Staff and the Company discussed the methodology that should be used to incorporate these revenue adjustments from the Sub 1142 rate case into the Company's DSM/EE rider filing. Based on these discussions, she stated that the Company will do the following:

a. For residential customers, the Company will extend the rate case test period to October 31, 2017 as the customer growth adjustment used in the rate case also included updated actual kWh sales through that time period; and

b. For non-residential customers, the Company will continue to utilize the rate case test period January 1, 2016 through December 31, 2016, as no adjustments were made to incorporate actual kWh sales past that date.

In addition, she indicated that the following modification will be made to calculate how much lost revenue is included in kWh sales for the test period. She explained that since the twelve-month rate case test period uses actual kWh sales, and participation in EE measures occurs throughout the year, in any given twelve-month period, a full year of lost revenues are not captured in test period kWh sales, as all measures are not in place at the beginning of the test period. The Company believes it is appropriate to quantify the actual incremental savings by month during that twelve-month rate case test period to calculate the amount of lost revenues that is truly being reflected in the new base rates that will be recovered from customers. Witness Miller testified that the difference between the annualized amount of energy savings and the actual amount of energy savings should be recovered through the Company's DSM/EE rider. The final result of the adjustment for the 2019 rate period is a reduction in NLR requested for residential customers in the amount of ($1,669,505) and an increase in NLR requested for non-residential customers in the amount of $1,361,119.

In his supplemental testimony, witness Maness indicated that the Public Staff agrees that this adjustment is appropriate for purposes of this proceeding.

[1] For rate period 2018, the net adjustment is estimated to be an increase of approximately $1,022,000; however, this adjustment would not be reflected in the rates until rate period 2018 is trued up in a future proceeding.

Further, in her supplemental testimony, witness Miller testified that during the course of the Company's review of its DSM/EE filing in this docket, DEP discovered that, although the EM&V results received in 2017 for the EnergyWise for Business Program had been appropriately applied prospectively, these results had not been included in calculation of the filed EMF rate. Accordingly, in its Supplemental Filing the Company updated Vintages 2016 and Vintage 2017 to reflect the revised kW savings included in the EnergyWise for Business EM&V report, which results in a reduction of PPI for non-residential customers in the amount of ($8,468) for Vintage 2016 and a reduction in PPI for non-residential customers in the amount of ($47,721) for Vintage 2017.

Witness Miller also testified that during the analysis to determine the appropriate Vintage 2017 lost revenues for non-residential customers, the Company found that there were certain non-residential customers in the lighting program whose benefits were inadvertently calculated using the residential lost revenue rate. In the Supplemental Filing, the Company made an adjustment that corrects that error. According to witness Miller, the impact on NLR for Vintage 2017 non-residential EE Lighting is ($33,469) for Vintage 2017 and ($93,299) for Vintage 2019.

In his supplemental testimony, witness Maness indicated that the Public Staff agrees that this adjustment is appropriate for purposes of this proceeding.

With respect to DEP's proposed adjustments reflected in the Supplemental Filing, the Commission notes that no party opposed such recovery, and the Public Staff has agreed that they are reasonable for purposes of this proceeding. The Commission finds that such proposed recovery is consistent with the Commission's orders in Docket Nos. E-2, Sub 931 and Sub 1145, and that NLR and PPI are appropriate for recovery in this proceeding, with the prospective rate period costs subject to further review in DEP's future annual DSM/EE rider proceedings. The Commission concludes that DEP has complied with N.C. Gen. Stat. § 62-133.9, Commission Rule R8-69, and the Commission's orders in Docket Nos. E-2, Sub 931 and Sub 1145, with regard to calculating costs and utility incentives for the test and rate periods at issue in this proceeding.

Therefore, the Commission concludes that for purposes of the DSM/EE EMF billing rates to be set in this proceeding, DEP's reasonable and prudent North Carolina retail test period costs and incentives, consisting of its amortized DSM/EE O&M costs, capital costs, taxes, amortized incremental A&G costs, carrying charges, NLR, and PPI, are $168,007,613. The reasonable and appropriate amount of test period DSM/EE rider revenues and adjustments to take into consideration in determining the test year and prospective period DSM/EE under- or over-recovery is $157,320,600. Therefore, the aggregate DSM/EE under-recovery for purposes of this proceeding is $10,687,013.

For purposes of the DSM/EE rider to be set in this proceeding, and subject to review in DEP's future DSM/EE rider proceedings, the Commission concludes that DEP's reasonable and appropriate estimate of its North Carolina retail DSM/EE program rate period amounts, consisting of its amortized O&M costs, capital costs, taxes, amortized incremental A&G costs, carrying charges, NLR, and PPI, after incorporation of the adjustments reflected in the Company's Supplemental Filing, is $175,770,263, and this is the appropriate amount to use to develop the DSM/EE revenue requirement.

With regard to the revenue requirements per class, the Commission concludes that after assignment or allocation to customer classes in accordance with N.C. Gen. Stat. § 62-133.9, Commission Rule R8-69, and the orders in Docket No. E-2, Sub 931, the revenue requirements for each class, excluding NCRF, are as follows:

DSM/EE PROSPECTIVE COMPONENT:

Residential	$100,657,479
General Service EE	68,669,252
General Service DSM	6,086,071
Lighting	357,461
Total	$175,770,263

DSM/EE EMF:

Residential	$ 494,880
General Service EE	11,979,271
General Service DSM	(1,790,030)
Lighting	2,892
Total	$10,687,013

Furthermore, the Commission finds that the appropriate and reasonable North Carolina retail class level kWh sales for use in determining the DSM/EE and DSM/EE EMF billing factors in this proceeding are as follows: Residential class – 15,740,238,953; General Service class EE – 9,852,771,378; General Service class DSM – 9,737,467,991; and Lighting class – 361,265,217.

Based on the testimony and exhibits of witnesses Miller and Evans, the testimony and exhibits of witness Maness, and the entire record in this proceeding, the Commission finds and concludes that the forward-looking DSM/EE rates as proposed by DEP in the Supplemental Filing to be charged during the rate period for the Residential, General Service, and Lighting rate schedules are appropriate. The Commission further concludes that the DSM/EE EMF billing factors as proposed by DEP in the Supplemental Filing are appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 20-21

The evidence for these findings of fact can be found in the testimony of NC Justice Center witness Neme, Public Staff witness Williamson, and DEP witness Evans.

Company witness Evans noted that Vintage 2017 of the Company's DSM and EE programs produced over 416 million kWh of energy savings and over 450 MW of capacity savings, which produced net present value of avoided cost savings of close to $287 million.

Witness Evans testified that opt-outs by qualifying industrial and commercial customers have had a significant impact on the Company's overall non-residential participation and the associated impacts. For Vintage 2017, 4,165 eligible customer accounts opted out of participating in DEP's non-residential portfolio of EE programs, and 4,099 eligible customer accounts opted out of participating in the Company's non-residential DSM programs. Witness Evans stated that to reduce opt-outs, the Company continues to evaluate and revise its non-residential portfolio of programs to accommodate new technologies, eliminate product gaps, remove barriers to participation, and make its programs more attractive to opt-out eligible customers. It also continues to leverage its Large Account Management Team to make sure customers are informed about product offerings.

NC Justice Center witness Neme testified that in the three years from 2015 through 2017, DEP's efficiency programs have saved enough energy at the time of system peak to eliminate the need for the equivalent of approximately two and half natural gas peaker plants. He also commended the Company for including a wide range of efficiency measures and programs in its DSM/EE portfolio, including "some national state-of-the art program design features." However, witness Neme noted that DEP's 2019 projected energy savings are 0.84%, which he indicated is below the 1% annual energy savings target contained in the settlement of the then-proposed merger of Duke Energy and Progress Energy (Merger Settlement).[1]

In his testimony, witness Neme also made several recommendations related to DSM/EE portfolio design, cost-effectiveness analysis, and EM&V. He emphasized that the complicated issues that he raises in his testimony would probably be best addressed, at least initially, through in-depth discussions between the utilities and other parties. Thus, he recommended that the Commission refer those issues to the DEP/DEC Collaborative, with a requirement that DEP report back on decisions in its 2019 DSM/EE rider proceeding. In particular, he recommended that DEP should leverage its Collaborative to discuss: (a) ways to improve participation in the Company's Residential Smart $aver EE Program, such as establishing a midstream channel for promoting measures, increasing incentives, and enhancing marketing; (b) greater promotion of whole-building retrofits, with an initial focus on targeting low-income communities; (c) building on DEP's recent successes in promoting measures in the midstream channel of its Non-Residential Prescriptive Rebate measure; (d) the potential to reduce the number of customers who opt out by educating customers who are eligible to opt out on available programs and/or improving program design to make programs more attractive to these customers; (e) the value of a Technical Reference Manual (TRM); (f) the propriety of assuming a one-year life for savings from the MyHER; (g) the impact of EISA on the Company's savings assumptions for residential light bulbs; and (h) the appropriateness of including non-electric benefits in cost-effectiveness analyses In addition, he suggested that the Collaborative explore program options for decreasing emphasis on short-lived savings, increasing investment in longer-lived measures, filling the "savings gap" that will be created by the elimination of most residential-lighting savings potential in 2020, and increasing program offerings to low-income communities. He noted that analysis and consideration of his program ideas will likely require more than a quarterly Collaborative meeting.

[1] The Merger Settlement was approved by the Public Service Commission of South Carolina in Docket No. 2011-158-E.

Public Staff witness Williamson also discussed his concerns regarding the fact that the EE lighting market is being transformed and that non-specialty LED lighting will likely become the baseline standard for general service bulb technologies by January 2020, as the second phase of the federal Energy Independence and Security Act (EISA) goes into effect, thereby decreasing savings from EE lighting programs. He indicated that it appears that the lighting market may be close to adopting EE lighting technologies as baseline and that further incentives for certain EE lighting measures for certain customers may not be necessary after January 1, 2020. Witness Williamson recommended that the Company include in its 2019 rider filing its plans for general service lighting measures in all of its EE programs that include lighting measures.

Witness Williamson also testified that the Company was in the process of installing Advanced Metering Infrastructure (AMI) meters and new customer information systems, and there may be some redundancy in the information available through these new systems and the information provided through the MyHER Program. He stated that the EM&V for the MyHER Program will need to clearly isolate any savings associated with enhanced access to customer data provided through AMI and customer information systems from the impacts solely attributable to the customized suggestions for the home provided by the MyHER Program.

In his rebuttal testimony, DEP witness Evans testified that given that the updated customer information system and billing system will not be in service for several years, he believes that witness Williamson's observations relating to potential overlap between AMI/customer information system and the MyHER Program are premature. Nevertheless, witness Evans indicated that the Company will work with the Public Staff to evaluate the MyHER Program's energy savings, recognizing the impacts of AMI and the updated customer information system.

In response to witness Williamson's comments regarding the impact of EISA on the Company's EE lighting programs, witness Evans stated that the Company is amenable to discussing its plans for EE programs that include general use lighting measures in its 2019 DSM/EE rider filing.

Witness Evans testified that while the Company does not necessarily agree with all of the recommendations included in witness Neme's testimony, it does agree that the Company's Collaborative meetings are the appropriate forum to discuss his program ideas. Witness Evans indicated that given the commonality between DEC's and DEP's programs, a combined DEC/DEP Collaborative would be preferable. He also agreed with witness Neme's assessment that quarterly meetings would be insufficient to adequately address the issues raised in his testimony, and recommended that the Collaborative meetings be expanded to every two months, as was approved in the Sub 1164 Order.

In its post-hearing brief, NC Justice Center reiterated witness Neme's testimony that DEP failed to reach the savings target of 1% per year agreed upon by DEP as part of the Merger Settlement. NC Justice center stated that it continues to have concerns about DEP's: (1) over reliance on short-lived measures, particularly its residential behavioral program My Home Energy Report; (2) inadequate promotion of longer-lived measures and comprehensive treatment of buildings; (3) insufficient planning to offset a significant loss of lighting savings once the 2020 federal EISA efficiency standards go into effect; (4) need to reach more lower-income communities and deliver programs that reach rental units; and (5) failure to account for all benefits achieved when calculating the cost-effectiveness of its programs. NC Justice Center urged the Commission to order DEP to take up these issues in the Collaborative over the course of the next year.

The Commission concludes that the Collaborative is the appropriate forum for consideration of all the issues raised by witness Neme as outlined herein. The Collaborative should also consider the issues raised by Public Staff witness Williamson regarding the MyHER program and the impact of upcoming lighting standards. The Commission agrees that given the overlap between DEC's and DEP's programs, as well as the stakeholders who participate in each utility's Collaborative, a combined Collaborative is appropriate and should meet every other month as suggested by witness Evans.

IT IS, THEREFORE, ORDERED as follows:

1. That the appropriate DSM/EE EMF billing factors, excluding NCRF, for the Residential, General Service, and Lighting rate classes are: 0.003 cents per kWh for the Residential class; 0.122 cents per kWh for the EE component of General Service classes; (0.018) cents per kWh for the DSM component of General Service classes; and 0.001 cents per kWh for the Lighting class. These DSM/EE EMF billing factors do not change when the NCRF is included.

2. That the appropriate forward-looking DSM/EE rates to be charged by DEP during the rate period for the Residential, General Service, and Lighting rate classes (excluding NCRF) are: 0.640 cents per kWh for the Residential class; 0.697 cents per kWh for the EE component of General Service classes; 0.063 cents per kWh for the DSM component of General Service classes; and 0.099 cents per kWh for the Lighting class. The appropriate forward-looking DSM/EE rates to be charged by DEP during the rate period, including NCRF, are increments of: 0.641 cents per kWh for the Residential class; 0.698 cents per kWh for the EE component of the General Service classes; 0.063 cents per kWh for the DSM component of the General Service classes; and 0.099 cents per kWh for the Lighting class.

3. That the appropriate total DSM/EE annual riders including the DSM/EE rate and the DSM/EE EMF rate (including NCRF) for the Residential, General Service, and Lighting rate classes are increments of 0.644 cents per kWh for the Residential class, 0.820 cents per kWh for the EE portion of the General Service classes, 0.045 cents per kWh for the DSM portion of the General Service classes, and 0.100 cents per kWh for the Lighting class.

4. That DEP shall file appropriate rate schedules and riders with the Commission in order to implement these adjustments as soon as practicable. Such rates are to be effective for service rendered on or after January 1, 2019.

5. That DEP shall work with the Public Staff to prepare a joint proposed Notice to Customers giving notice of rate changes ordered by the Commission herein, and DEP shall file such proposed notice for Commission approval as soon as practicable.

6. That the Company shall propose modifications to the Residential Smart $aver EE Program no later than December 31, 2018, with the goal of restoring the TRC score to 1.00 or greater, and the Company shall include a discussion of the impact of these modifications and any other actions it has taken to improve cost-effectiveness in next year's DSM/EE rider proceeding.

7. That in its next rider application, DEP shall address the continuing cost-effectiveness of the Non-Residential Smart $aver Performance Incentive Program and if it is not cost-effective, provide details of plans to modify or close the program.

8. That in its next rider application, DEP shall address the continuing cost-effectiveness of the MyHER Program and if it is not cost-effective, provide details of plans to modify or close the program.

9. That the results of the EM&V report for the MyHER Program, as shown in Evans Exhibit I, are accepted conditionally for purposes of this proceeding. The Public Staff shall continue to review this report and offer further recommendations for the Company's consideration in the next DSM/EE rider proceeding.

10. That the Company should incorporate the recommendation made by Public Staff witness Williamson that the program evaluator for the Company's EE Lighting Program should (a) include the basis for the selected weighting methodology (weightings based on bulb sales, measure savings, or other metric) when assessing program savings, and (b) indicate what other weighting methodologies were considered and why they were rejected, and why the selected methodology is preferable, in future EM&V reports for the EE Lighting Program.

11. That DEP shall leverage the DEP Collaborative to discuss the EM&V issues and program design issues raised in the testimony of NC Justice Center witness Neme as discussed herein, as well as the issues raised by Public Staff witness Williamson regarding the MyHER program and the impact of upcoming lighting standards. The results of these discussions, specifically including the salient points arising from the discussion of the issues raised in the testimonies of witnesses Neme and Williamson, shall be reported to the Commission in the Company's 2019 DSM/EE rider filing. In addition, the report should identify all participants in the Collaborative discussions; identify any new ideas, proposals, programs and/or program adjustments presented or arising out of the discussions; summarize the Company's analysis or evaluation of such ideas, proposals, programs or program adjustments; and provide a status update with respect to unfinished or future discussions of the Collaborative.

12. Beginning in 2019, the combined DEC/DEP Collaborative shall meet every other month.

ISSUED BY ORDER OF THE COMMISSION.
This the 29th day of November, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. E-2, SUB 1175

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Progress, LLC,	)	
for Approval of Renewable Energy and Energy	)	ORDER APPROVING REPS AND REPS
Efficiency Portfolio Standard Cost Recovery	)	EMF RIDER AND APPROVING REPS
Rider Pursuant to G.S. 62-133.8 and	)	COMPLIANCE REPORT
Commission Rule R8-67	)	

HEARD: Tuesday, September 18, 2018 at 9:40 a.m. in the Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Daniel E. Clodfelter, Presiding, Chairman Edward S. Finley, Jr., and Commissioners ToNola D. Brown-Bland, Jerry C. Dockham, James G. Patterson, Lyons Gray and Charlotte A. Mitchell

APPEARANCES:

For Duke Energy Progress, LLC:

Kendrick C. Fentress, General Counsel, Duke Energy Corporation, 410 South Wilmington Street, NCRH 20/P.O. Box 1551, Raleigh, North Carolina 27602

Robert W. Kaylor Law Office of Robert W. Kaylor, P.A. 353 E. Six Forks Road, Suite 260 Raleigh, North Carolina 27609

For Carolina Utility Customers Association, Inc.:

Robert F. Page, Crisp & Page, PLLC, 4010 Barrett Drive, Suite 205, Raleigh, North Carolina 27609

For North Carolina Sustainable Energy Association:

Benjamin Smith, Regulatory Counsel, North Carolina Sustainable Energy Association, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For the Using and Consuming Public:

Tim R. Dodge, Staff Attorney and Robert B. Josey, Staff Attorney, Public Staff, North Carolina Utilities Commission 4326 Mail Service Center Raleigh, North Carolina 27699

BY THE COMMISSION: On June 20, 2018, Duke Energy Progress, LLC (DEP or the Company) filed its 2017 REPS Compliance Report and application seeking an adjustment to its North Carolina retail (NC Retail) rates and charges pursuant to N.C.G.S. § 62-133.8(h) and

Commission Rule R8-67, which require the Commission to conduct an annual proceeding for the purpose of determining whether a rider should be established to permit the recovery of the incremental costs incurred to comply with the requirements of the Renewable Energy and Energy Efficiency Portfolio Standard (REPS), N.C.G.S. § 62-133.8(b), (d), (e) and (f), and to true up any under-recovery or over-recovery of compliance costs. DEP's application was accompanied by the testimony and exhibits of Megan W. Jennings, Renewable Compliance Manager, and Veronica I. Williams, Rates and Regulatory Strategy Manager. In its application and pre-filed testimony, DEP sought approval of its proposed REPS rider, which incorporated the Company's proposed adjustments to its North Carolina retail rates.

On July 2, 2018, the Commission issued an Order setting this matter for hearing, establishing deadlines for the submission of intervention petitions, intervenor testimony, and DEP rebuttal testimony, requiring the provision of appropriate public notice, and mandating compliance with certain discovery guidelines.

The Commission issued orders granting petitions to intervene filed by the North Carolina Sustainable Energy Association (NCSEA) and the Carolina Utility Customers Association, Inc. (CUCA), on June 29, and July 24, 2018, respectively. The intervention and participation by the Public Staff is recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19(e).

On August 29, 2018, the Public Staff filed the affidavits and exhibits of Jay B. Lucas, an engineer in the Public Staff Electric Division, and Michelle M. Boswell, an accountant in the Public Staff Accounting Division.

On September 12, 2018, DEP filed a motion requesting that all of its witnesses be excused from attending the evidentiary hearing and that the pre-filed testimony, exhibits, and affidavits of the witnesses and affiants be received into evidence and made a part of the record in this proceeding. On September 13, 2018, the Commission issued an order granting that motion.

This matter came on for hearing on September 18, 2018. DEP presented the testimony and exhibits of witnesses Jennings and Williams, and the Public Staff presented the affidavits of witnesses Boswell and Lucas. All pre-filed testimony, exhibits, and affidavits of the DEP and Public Staff's witnesses were received into evidence.

Based upon the foregoing, the testimony, exhibits, and affidavits introduced at the hearing, the records in the North Carolina Renewable Energy Tracking System (NC-RETS), and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. DEP is a duly organized limited liability company existing under the laws of the State of North Carolina, is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North Carolina, and is subject to the jurisdiction of the Commission as a public utility. DEC is also an electric power supplier as defined in N.C.G.S. § 62-133.8(a)(3). DEP is lawfully before this Commission based upon its application filed pursuant to N.C.G.S. § 62-133.8 and Commission Rule R8-67.

2. For purposes of DEP's annual rider established pursuant to N.C.G.S. § 62-133.8(h), the test period and billing period for this proceeding are, respectively, the twelve-month period beginning April 1, 2017, and ending March 31, 2018, and twelve-month period beginning December 1, 2018, and ending November 30, 2019.

3. Section 62-133.8(h) of the North Carolina General Statutes authorizes an electric power supplier to recover the "incremental costs" of compliance with the REPS requirement through an annual REPS rider. The "incremental costs," as defined in N.C.G.S. § 62-133.8(h)(1), include the reasonable and prudent costs of compliance with REPS "that are in excess of the electric supplier's avoided costs other than those costs recovered pursuant to N.C.G.S. § 62-133.9." The term "avoided costs" includes both avoided energy costs and avoided capacity costs.

4. For calendar year 2017, the Company was required to meet at least 6% of its previous year's North Carolina retail electric sales by a combination of renewable energy and energy reductions due to the implementation of energy efficiency measures. Also in 2017, energy in the amount of at least 0.14% of the previous year's total electric power sold by DEP to its North Carolina retail customers must be supplied by solar energy resources.

5. Beginning in 2012, N.C.G.S. §§ 62-133.8(e) and (f) require DEP and the other electric suppliers of North Carolina, in the aggregate, to procure a certain portion of their renewable energy requirements from electricity generated from swine and poultry waste, based on each electric power supplier's respective pro-rata share derived from the ratio of its North Carolina retail sales as compared to total North Carolina retail sales. The Commission further established the annual allocation of the state-wide poultry waste requirement applicable to 2016-2018 among electric power suppliers and utility compliance aggregators in its August 5, 2016, Order Establishing 2016, 2017, and 2018 Poultry Waste Set-Aside Requirement Allocation in Docket No. E-100, Sub 113 (2016 Poultry Allocation Order). In its Order Modifying the Swine and Poultry Waste Set-Aside Requirements and Providing Other Relief, issued on October 16, 2017, in Docket No. E-100, Sub 113 (2017 Delay Order), the Commission modified the aggregate 2017 poultry waste set-aside requirement to remain at the same level as the 2016 requirement and delayed by one year the scheduled increases in the requirement. In the 2017 Delay Order, the Commission also postponed for one additional year the swine waste set-aside requirement, directing that the swine waste set-aside requirement would commence in 2018, rather than 2017.

6. DEP has agreed to provide compliance services, including the procurement of renewable energy certificates (RECs), to the following electric power suppliers, pursuant to N.C.G.S. § 62-133.8(c)(2)(e): the Town of Black Creek, the Town of Lucama, the Town of Sharpsburg, the Town of Stantonsburg, and the Town of Winterville (collectively, Wholesale Customers). DEP's contractual obligation to provide REPS services to the Wholesale Customers ended December 31, 2017.

7. DEP has complied with the 2017 REPS compliance requirements, for itself and the Wholesale Customers, by submitting for retirement 2,210,451 RECs, including 16,358 Senate Bill 886 (SB 886) RECs, each of which counts for two poultry waste RECs and one general REC, to meet its overall total REPS requirement of 2,243,167 RECs. Within this total, the Company submitted for retirement 52,344 RECs to meet the solar set-aside requirement and 15,358 RECs,

along with 16,358 SB 886 RECs (which count as 32,716 poultry waste set-aside RECs), to meet the poultry waste set-aside requirement.

8. DEP and the Wholesale Customers met their 2017 REPS obligations, including those the set-aside requirements as modified or delayed by the Commission's Orders issued in Docket No. E-100, Sub 113.

9. When DEP filed its application, DEP expressed uncertainty about its ability to meet the poultry and swine waste set-aside requirements for compliance year 2018. On October 8, 2018 (subsequent to the September 18 hearing date in this proceeding), the Commission issued its Order Modifying the Swine and Poultry Waste Set-Aside Requirements and Providing Other Relief in Docket No. E-100, Sub 113 (2018 Delay Order) which: modified the 2018 swine waste set-aside requirement by establishing that requirement for DEP and the other electric public utilities at 0.02% of prior year retail sales; delayed the 2018 swine waste set-aside requirements for electric membership corporations and municipalities until 2019; modified the 2018 poultry waste set-aside requirement by establishing that requirement at 300,000 MWh for all electric suppliers; and delayed by one year the future scheduled increases in the poultry and swine waste set-aside requirements.

10. The research activities funded by DEP during the test period are incremental costs reasonably and prudently incurred by DEP to fund research that encourages the development of renewable energy, energy efficiency, or improved air quality and are within the annual $1-million limit established pursuant to N.C.G.S. § 62-133.8(h)(1)(b). It is appropriate to require DEP to continue to provide the results of its REPS-related research when these results are publicly available, and the procedures for third parties to access the results when they are proprietary in its future applications for the recovery of costs incurred to comply with the REPS requirements.

11. DEP appropriately calculated its avoided costs and incremental REPS compliance costs for the test period and billing period. For purposes of establishing the REPS experience modification factor (EMF) rider in this proceeding, DEP's incremental costs for REPS compliance during the test period were $42,744,260, including the costs incurred for its Wholesale Customers, and these costs were reasonably and prudently incurred. The Company's projected incremental costs for REPS compliance for the billing period total $40,959,120 for DEP retail customers only, as DEP's agreement to provide REPS compliance services to the Wholesale Customers ended effective December 31, 2017.

12. It is appropriate to approve DEP's request to recover other incremental costs and the costs of incentives provided to customers and program administrative costs related to the solar rebate program established pursuant to N.C.G.S. § 62-155(f), as incremental costs reasonably and prudently incurred and authorized for recovery pursuant to N.C.G.S. § 62-133.8(h)(1)(a) and (d).

13. DEP complied with the conditions related to cost recovery for the solar photovoltaic (PV) electric generating facilities located in Fayetteville, Warsaw, Camp Lejeune, and Elm City, which are owned by the Company. DEP's compliance requirement associated with these conditions is complete.

14. It is appropriate to approve DEP's request to recover other incremental costs of compliance with REPS pursuant to G.S. 62-133.8(h)(1)(a), as incremental costs reasonably and prudently incurred to comply with the REPS requirements.

15. DEP's allocation of incremental REPS compliance costs among customer classes for the purposes of calculating its proposed REPS and EMF rider charges is appropriate for this proceeding.

16. DEP's test period REPS expense under-collections were $2,124,217 for the residential class and $196,787 for the industrial class. DEP's test period over-collection, including interest, was $1,272,374 for the general service class. In addition, the Company appropriately credited to customers the following amounts received from REC suppliers during the test period related to contract amendments, penalties, and other conditions of the supply agreements: $325,340 for residential customers, $294,082 for general service customers, and $18,500 for industrial customers. Total test period charges to customers' accounts, including the under-collections offset by contract-related credits, were $1,798,877 for the residential class, and $178,287 for the industrial class. The total test period credit to the general service class, including the over-collection and contract-related credits, was $1,566,456. These amounts are exclusive of the regulatory fee.

17. DEP's North Carolina retail prospective billing period expenses for use in this proceeding are $19,004,704 for the residential class, $20,526,773, and $1,427,643, for the residential, general service, and industrial classes, respectively, excluding regulatory fee.

18. The appropriate monthly REPS EMF rider charges per customer account, excluding regulatory fee, to be charged to customers during the billing period are $0.12 for residential accounts and $8.11 for industrial accounts, and the appropriate monthly REPS EMF rider credit to be refunded to customers during the billing period is $(0.66) for general service accounts.

19. The appropriate monthly prospective REPS rider charges per customer account, excluding regulatory fee, to be charged to customers during the billing period are $1.30 for residential accounts, $8.61 for general service accounts, and $64.96 for industrial accounts.

20. The combined monthly REPS and REPS EMF rider charges per customer account, excluding the regulatory fee, to be charged to customers during the billing period are $1.42 for residential accounts, $7.95 for general service accounts, and $73.07 for industrial accounts. Including the regulatory fee, the combined monthly REPS and REPS EMF rider charges per customer account to be collected during the billing period are $1.42 for residential accounts, $7.96 for general service accounts, and $73.17 for industrial accounts.

21. DEP's REPS rider charges, including the regulatory fee, to be charged to each customer account for the billing period is within the annual limits established for each class in N.C.G.S. § 62-133.8(h)(4).

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 1

This finding of fact is essentially informational, procedural, and jurisdictional in nature and is uncontested.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 2-6

The evidence supporting these findings of fact is found in in the direct testimony and exhibits of DEP witnesses Jennings and Williams, including DEP's 2017 REPS Compliance Report that was sponsored as an exhibit to witness Jennings' testimony, and in the affidavit of Public Staff witness Lucas. These findings of fact are essentially informational, jurisdictional and procedural in nature and are not contested.

Section 62-133.8(h)(4) requires the Commission to allow an electric power supplier to recover all of its incremental costs incurred to comply with N.C.G.S. § 62-133.8 though an annual rider. N.C.G.S. § 62-133.8(h)(1) provides that "incremental costs" means all reasonable and prudent costs incurred by an electric power supplier to comply with the REPS requirement that are in excess of the electric power supplier's avoided costs other than those costs recovered pursuant to N.C.G.S. § 62-133.9. The term "avoided costs" includes both avoided energy and avoided capacity costs. Commission Rule R8-67(e)(2) provides that the "cost of an unbundled renewable energy certificate to the extent that it is reasonable and prudently incurred is an incremental cost and had no avoided cost component."

Commission Rule R8-67(e)(1) provides that the Commission shall schedule an annual public hearing to review an electric utility's REPS compliance costs. Subdivision (e)(3) of Rule R8-67 further provides that the test period for REPS rider proceedings shall be the same as that used by the utility in its fuel charge adjustment proceedings, which is specified in Commission Rule R8-55(c) for DEP to be the twelve months ending March 31 of each year. Commission Rule R8-67(e)(5) provides that "[t]he REPS EMF rider will reflect the difference between reasonable and prudently incurred incremental costs and the revenues that were actually realized during the test period under the REPS rider then in effect." Commission Rule R8-67(e)(4) further provides that the REPS and REPS EMF riders shall be in effect for a fixed period, which "shall coincide, to the extent practical, with the recovery period for the cost of fuel and fuel-related cost rider established pursuant to Rule R8-55." In its current fuel charge adjustment proceeding, Docket No. E-2, Sub 1173, and in this proceeding, DEP proposed that its rate adjustments take effect on December 1, 2018, and remain in effect for a twelve-month period.

The test period and the billing period proposed by DEP were not challenged by any party. The Commission concludes that the test period and billing period appropriate for this proceeding are the twelve months beginning April 1, 2017, and ending March 31, 2018, and the twelve months ending November 30, 2019, respectively.

Pursuant to N.C.G.S. § 62-133.8(b)(1), each electric public utility in the state is required to produce a certain percentage of its North Carolina retail electric sales from various renewable energy or EE resources. An electric public utility may meet these requirements from any one or more of the following compliance options listed in N.C.G.S. § 62-133.8(b)(2): (a) generating electric power at a new renewable energy facility; (b) using a renewable energy resource to generate electric power at a generating facility other than the generation of electric power from waste heat derived from the combustion of fossil fuel; (c) reducing energy consumption through the implementation of energy efficiency measures; (d) purchasing electric power from a new renewable energy facility; (e) purchasing RECs produced from in-State or out-of-state new renewable energy facilities; (f) using electric power that is supplied by a new renewable energy facility or saved due to the implementation of an EE measure that exceeds the requirements of the REPS in any calendar year as a credit toward the requirements of the REPS in the following calendar year; or (g) electricity demand reduction. Each of these measures is subject to additional limitations and conditions. For 2017, an electric public utility must meet a total REPS requirement equal to at least six percent of its previous year's North Carolina retail electric sales by a combination of these measures.

Subsection 62-133.8(d) requires a certain percentage of the total electric power sold to retail electric customers in the State, or an equivalent amount of energy, to be supplied by a combination of new solar electric facilities and new metered solar thermal energy facilities. The percentage requirement for solar resources in 2017 is 0.14%.

Subsections 62-133.8(e) and (f) require DEP and the other electric suppliers of North Carolina, in the aggregate, to procure a certain portion of their renewable energy requirements from electricity generated from swine and poultry waste. The swine waste energy requirement is based on a percentage of retail sales, similar to the solar energy requirement. The poultry waste energy requirement is based on each electric power supplier's respective pro-rata share derived from the ratio of its North Carolina retail sales as compared to the total North Carolina retail sales. Pursuant to the Commission's Order on Pro-Rata Allocation of Aggregate Swine and Poultry Waste Set-Aside Requirements and Motion for Clarification, issued on March 31, 2010, in Docket No. E-100, Sub 113, DEP's share of the aggregate State set-aside requirements for energy from swine and poultry waste is based on the ratio of its North Carolina retail kilowatt-hour sales for the previous year divided by the previous year's total North Carolina retail kilowatt-hour sales. The Commission's 2016 Poultry Allocation Order established DEP's allocation share of the state-wide poultry waste requirement to be effective for the 2017 compliance year. Subsequently, the Commission's 2017 Delay Order modified the 2017 state-wide poultry waste requirement to remain at 2016 levels. The 2017 Delay Order also postponed the swine waste requirement for one year, to commence in 2018 rather than 2017.

DEP witness Jennings testified that DEP submitted its 2017 REPS compliance report as Jennings Exhibit No. 1 and that this report contained all the information required by Commission Rule R8-67(c) in the aggregate for DEP and the Wholesale Customers for which DEP has contracted to provide REPS compliance services. In its 2017 compliance report, DEP stated that it provided energy resources and compliance reporting services for the Town of Black Creek, the Town of Lucama, the Town of Sharpsburg, the Town of Stantonsburg, and the Town of Winterville. Public Staff witness Lucas noted that DEP indicated in response to data requests that it no longer provides any REPS compliance services to the Wholesale Customers as of January 1, 2018.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7-9

The evidence supporting these findings of fact is found in the direct testimony and exhibits of DEP witnesses Jennings and Williams, including DEP's 2017 REPS Compliance Report, which was admitted into evidence as Jennings Exhibit No.1, and in the affidavit of Public Staff witness Lucas. In addition, the Commission takes judicial notice of the information contained in NC-RETS.

Witness Jennings testified that DEP submitted for retirement 2,210,451 RECs, which included 16,358 Senate Bill 886 (SB 886) RECs, each of which counts for two poultry waste and one general REC, to meet its Total Requirement of 2,243,167 RECs. She defined the "Total Requirement" as DEP's overall REPS requirement. Within this total, the Company submitted for retirement 52,344 RECs to meet the solar set-aside requirement, along with 16,358 SB 886 RECs (which count as 32,716 poultry waste set-aside RECs), to meet the poultry waste set-aside requirement. Witness Jennings' further testified that she estimates that, for compliance year 2018, the Company would be required to submit for retirement 3,682,990 RECs to meet its Total Requirement defined according to N.C.G.S. § 62-133.8(b). Within this total, the Company estimated it would retire the following: 73,660 solar RECs, 25,781 swine waste RECs, and 197,318 poultry waste RECs. For 2019, her testimony included estimates of 3,724,847 RECs for the Total Requirement and, within this total, estimates of the following set-aside requirements: 74,497 solar RECs, 26,074 swine waste RECs and 253,695 poultry waste RECs.

Witness Jennings next testified that the Company had complied with its "General Requirement" (DEP's Total Requirement, net of the Solar, Swine Waste and Poultry Waste requirements) for 2017. Pursuant to NC-RETS Operating Procedures, she testified that the Company has submitted for retirement 2,142,749 RECs to meet the General Requirement. Specifically, the RECs to be used for 2017 compliance have been transferred from the NC-RETS Progress Energy Electric Power Supplier account to the Progress Energy Compliance Sub-Account and the Sub-Accounts of the Wholesale Customers.

Witness Jennings also testified that DEP procured or produced sufficient RECs to meet its 2017 solar set-aside requirement of 52,344 RECs. In addition, she testified that the Company met its 2017 poultry waste requirement of 48,074 RECs, including 15,358 poultry waste RECs and 32,716 SB 886 bonus poultry RECs (generated from 16,358 general requirement SB 886 RECs). Pursuant to NC-RETS Operating Procedures, the Company submitted these solar RECs and poultry waste RECs for retirement. The RECs were transferred from the Progress Energy Electric Power Supplier Account to the Progress Energy Compliance Sub-Account and the Sub-Accounts of its Wholesale Customers.

In her direct testimony, Company witness Jennings testified DEP could comply with the then-current poultry waste set-side requirement in 2018, though future compliance was dependent on the performance of poultry waste-to-energy developers on current contracts. Witness Jennings' testimony also indicated that the Company did not expect to be able to meet its then-current swine waste requirement level for 2018, citing performance difficulties related to swine waste-to-energy developers on current contracts, and delays in swine waste-to-energy developers becoming commercially operational on new contracts. She noted difficulties, as understood by the Company, that are being experienced by current projects in achieving full REC output, related to: the inability to secure firm and reliable sources of swine waste feedstock from waste producers in North Carolina; difficulties securing project financing; and technological challenges encountered when ramping up production. As detailed in witness Jennings's direct testimony as well as in the Company's Joint Semiannual Progress Report, filed on May 31, 2018, in Docket No. E-100, Sub 113A, DEP continues to engage in numerous and diverse efforts to procure or develop resources to meet its swine waste set-aside requirements in a reasonable and prudent manner. The 2018 Delay Order modified DEP's swine waste requirement to 0.02% from 0.07%, modified the poultry waste requirement from 700,000 MWh to 300,000 MWh, and delayed the subsequent increases for an additional year, reflecting the Company's expectation of compliance difficulties as noted in her testimony.

Public Staff witness Lucas recommended that the Commission approve DEP's 2017 REPS Compliance Report. Specifically, he testified that for 2017 compliance, DEP needed to obtain a sufficient number of RECs and energy efficiency certificates (EECs) derived from eligible sources so that the total equaled 6% of the 2016 North Carolina retail electricity sales of itself and the Wholesale Customers. Additionally, he testified that DEP needed to pursue retirement of sufficient solar RECs to match 0.14% of retail sales in 2016 for itself and the Wholesale Customers, and of its pro-rata share of the 170,000 poultry waste RECs required by N.C.G.S. § 62-133.8(f). Further, he testified that the number of poultry waste RECs was established pursuant to the Commission's 2017 Poultry Allocation Order and 2017 Delay Order, and that the REPS requirement for swine waste, under N.C.G.S. § 62-133.8(e), was delayed until 2018 by the Commission's 2017 Delay Order.

No party disputed that DEP had fully complied with the applicable REPS requirements, or argued that DEP's REPS Compliance Report for 2017 should not be approved.

Based on the foregoing and the entire record herein, the Commission finds that DEP and the five Wholesale Customers for which it is providing REPS compliance services have complied with the REPS requirements for 2017, as modified by the Commission's 2017 Delay Order. Therefore, the Commission concludes that DEP's 2017 REPS Compliance Report should be approved, and that the RECs and EECs in the related NC-RETS compliance sub-accounts should be permanently retired. Finally, the Commission finds that, at the time DEP filed its application in this proceeding, it was uncertain whether it will be able to comply with the poultry and swine waste set-aside requirements for 2018, which have subsequently been modified pursuant to the Commission's 2018 Delay Order, and that this uncertainty persists as to future compliance years notwithstanding that the Company is committed to satisfying these requirements by continuing to pursue procurement of these resources in a reasonable and prudent manner.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence for this finding of fact is found in the testimony of DEP witnesses Jennings and Williams.

Witness Jennings identified in confidential Jennings Exhibit No. 3 the "Research," "Solar Rebate Program," and "Other Incremental" costs that the Company incurred or projects to incur in association with REPS compliance. With respect to research costs, Williams Exhibit No. 1 shows that the research costs are under the $1 million per year cap established in N.C.G.S. § 62-133.8(h)(1)(b).

In compliance with prior Commission Orders, witness Jennings supplied testimony and exhibits on the results and status of various studies, the costs of which DEP is seeking to recover in this docket.

No party disputed these costs or argued that the recovery of these costs through the REPS rider charges should be disallowed.

Based upon the foregoing and the entire record herein, the Commission finds that the research activities funded by DEP during the test period were reasonable and prudent costs incurred to fund research that encourages the development of renewable energy, energy efficiency, or improved air quality and do not exceed the one million dollar annual limit established pursuant to N.C.G.S. § 62-133.8(h)(1)(b). Therefore, the Commission concludes that DEP should be allowed to recover these costs through the REPS rider charges approved in this Order. In addition, the Commission finds that the research information DEP provided is helpful. Therefore, the Commission finds that it is appropriate to require DEP to continue filing this information with its future REPS compliance reports and applications to recover costs incurred to comply with the REPS Requirements, and to continue to provide procedures for third parties to access the results of studies that are subject to confidentiality agreements. For research projects sponsored by Electric Power Research Institute, DEP should provide the overall program number and specific project number for each project, as well as an internet address or mailing address that will enable third parties to inquire about the terms and conditions for access to any portions of the study results that are proprietary.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11-14

The evidence for these findings of fact is found in testimony and exhibits of DEP witnesses Jennings and Williams, and in the affidavits of Public Staff witnesses Boswell and Lucas.

DEP witness Williams testified regarding the calculation of DEP's avoided costs and its incremental costs of compliance with REPS requirements, based on incurred and projected costs provided by witness Jennings. N.C.G.S. § 62-133.8(h)(1) provides that "incremental costs" means "all reasonable and prudent costs incurred by an electric power supplier" to comply with the REPS requirements "that are in excess of the electric power supplier's avoided costs other than those costs recovered pursuant to N.C. Gen Stat. § 62-133.9." For purchased power agreements with a renewable energy facility, DEP subtracted its avoided cost from the total cost associated with the renewable energy purchase to arrive at the incremental cost for that renewable energy purchase during the period in question. Consistent with Commission Rule R8-67(e)(2), which provides that the cost of an unbundled REC is an incremental cost with no avoided cost component, witness Williams included in incremental costs the total amount of costs incurred during the test period for unbundled REC purchases. In addition to costs incurred or projected to be incurred for bundled or unbundled RECs, Williams Exhibit No. 1, Pages 1 and 2 identified the "Other Incremental," "Solar

Rebate Program" and "Research" costs that DEP has incurred or projects to incur in association with REPS compliance.

Williams Exhibit No. 1, Page 1 showed total NC Retail and Wholesale Customer incremental REPS compliance costs incurred during the test period as $42,744,260 ($42,645,949 for NC Retail only), and Williams Exhibit No. 1, Page 2 showed comparable projected incremental costs for the billing period as $40,959,120 (applicable to NC Retail only as compliance services for Wholesale Customers ended effective December 31, 2017).

Public Staff witness Lucas stated in his affidavit that DEP's proposed REPS rider charges are based on the projected costs and projected number of accounts subject to the REPS charge in the billing period. He further testified that the REPS EMF charges are based on the incremental costs in the test period and the average number of accounts subject to the REPS charge during the billing period, as more fully discussed in the affidavit of Public Staff witness Boswell. In addition, he testified that the Public Staff has reviewed the costs that produce the REPS and REPS EMF rider charges proposed by DEP in this proceeding, and that the Public Staff takes no issue with them. Accordingly, he further testified that the Public Staff recommends approval of the proposed rider charges as filed.

Pursuant to Ordering Paragraph No. 7 of the Commission's Order Approving REPS and REPS EMF Rider and Approving REPS Compliance Report, issued on November 17, 2017, in Docket No. E-2, Sub 1144 (2017 DEP REPS Order), DEP is required to "continue to file a worksheet explaining the discrete costs it includes as 'other incremental costs' in all future REPS proceedings." Witness Jennings's Exhibit No. 3 is a worksheet that is intended to meet this requirement by detailing the "Other Incremental Cost," "Solar Rebate Program Cost," and "Research Cost" that DEP is seeking to recover in this proceeding. Witness Jennings testified that "Other Incremental Cost" includes labor costs associated with REPS compliance activities and non-labor costs associated with administration of REPS compliance; however witness Jennings further testified that, as required by the Commission's Order Approving REPS and REPS EMF Rider REPS Compliance Report, issued on January 17, 2017, in Docket No. E-2, Sub 1109, no internal interconnection-related labor costs and non-labor costs have been included DEP's application for cost recovery in this proceeding. Witness Williams included the other incremental and research costs that were incurred in the Test Period in the EMF calculation. She explained that these costs are estimated for the Billing Period and included in the proposed REPS riders. She also testified that an amount equal to the annual amortization of Solar Rebate Program costs incurred pursuant to N.C.G.S. § 62-155(f) applicable to the billing period is also included for recovery in the proposed REPS rider.

Witness Jennings provided additional detail on the inclusion of Solar Rebate Program costs for recovery in the proposed REPS rider. As required by N.C.G.S. § 62-155(f), DEP filed an application for approval of its Solar Rebate Program in Docket Nos. E-7, Sub 1166 and E-2, Sub 1167. On April 3, 2018, in Docket Nos. E-7, Sub 1166 and E-2 Sub 1167, the Commission issued its Order Modifying and Approving Riders Implementing Solar Rebate Program. Witness Jennings testified in this current proceeding DEP's Solar Rebate Program offers reasonable incentives to residential and nonresidential customers for the installation of small customer-owned or leased solar energy facilities participating in the Company's net metering tariff. Witness

Jennings explained that, consistent with N.C.G.S. §§ 62-155(f) and 62-133.8(h), the Company had included labor and non-labor costs projected to be incurred in the billing period related to implementation of the Solar Rebate Program. Witness Jennings identified these costs, which include the annual amortization of incentives paid to customers and program administration costs, including labor, information technology, and marketing costs, in Jennings Confidential Exhibit No. 3.

The Commission notes that this is the first REPS rider proceeding in which DEP has included costs associated with its Solar Rebate Program for recovery through the REPS rider. Subsection 62-155(f) authorizes DEP to recover through the REPS rider charges all reasonable and prudent costs of incentives provided to customers and program administrative costs by amortizing the total program incentives distributed during a calendar year and administrative costs over a 20-year period, including a return component adjusted for income taxes at the utility's overall weighted average cost of capital established in its most recent general rate case. Additionally, N.C.G.S. § 62-133.8(h), as amended by House Bill 589, provides that an electric power supplier's cost recovery and customer charges under the REPS rider may include incremental costs incurred to "provide incentives to customers, including program costs, incurred pursuant to N.C.G.S. § 62-155(f)."

No party challenged DEP's calculation of its avoided costs or incremental costs to comply with the REPS requirements, or otherwise disputed whether these costs were reasonable and prudently incurred.

Witness Williams also testified regarding the Company's Fayetteville, Warsaw, Camp Lejeune, and Elm City solar photovoltaic electric generating facilities (DEP Solar PV Facilities), which were in service for the duration of the test period. She testified that the Commission included two conditions related to cost recovery for the DEP Solar PV Facilities in its December 16, 2014, orders approving the transfer of each Certificate of Public Convenience and Necessity (CPCN) in Docket No. E-2, Subs 1054, 1055, 1056, respectively, and in its April 14, 2015, order issuing a CPCN in Docket No. E-2, Sub 1063 (collectively, CPCN Orders). The first condition addressed the avoided cost values to be used by the Company in subsequent calculations of the avoided and incremental components of total cost for each of the facilities. The Company agreed that, in the appropriate REPS rider and general rate case proceedings, it would determine the levelized avoided cost per MWh for each facility by using the same avoided energy and capacity cost values included in the Company's analysis of the revenue requirements for each facility, as presented during the CPCN proceedings. The second condition relates to DEP's ability to realize certain tax benefits included in the Company's revenue requirements analysis for each facility as presented during the CPCN proceedings. The condition provides that, in the appropriate REPS rider and general rate case proceedings, DEP will separately itemize the actual monetization of the tax benefits listed in the Commission's orders within its calculation of the levelized revenue requirement per MWh for each facility, so that it may be compared with the monetization of such tax benefits included in the Company's revenue requirement analysis of each facility presented during the CPCN proceedings. To the extent the Company fails to fully realize the tax benefits it originally assumed in its estimated revenue requirements, costs associated with the increased revenue requirements (with a limited exception) will be presumed to be imprudent and unreasonably incurred. The condition further provides that DEP may rebut this presumption with evidence supporting the reasonableness and prudence of its actual monetization of the tax credits.

Witness Williams testified that, in the Company's 2016 annual REPS rider filing in Docket No. E-2, Sub 1109 and its 2017 annual REPS rider filing in Docket No. E-2, Sub 1144, the Company updated its original models of estimated annual revenue requirements to reflect its actual experience to date with regard to each of the specified tax-related benefits, and that the Company updated its estimates of the timing of realization of the relevant tax benefits in future tax years. In addition, she testified that the avoided cost components of the revenue requirement calculations updated in these REPS rider dockets were fixed at the levels included in the original CPCN revenue requirement calculations, as required by the CPCN Orders. In each docket, the updated annual levelized revenue requirement for each project remained below the annual levelized avoided cost, and no incremental REPS cost was included for recovery in the respective REPS rider.

Witness Williams further testified that, on June 1, 2017, DEP filed its Application for Adjustment in Rates and Request for Accounting Order in Docket No. E-2, Sub 1142, the Company's only general rate case proceeding since the issuance of the CPCN Orders. The DEP Solar PV Facilities costs were included in total in the revenue requirement calculated and subject to recovery in base rates in the general rate case docket. The Commission issued its final order in that general rate case proceeding on February 23, 2018, in which the Commission accepted DEP's conclusion that the facility costs included in its proposed base rates were prudently incurred and approved recovery through base rates. Witness Williams explained that the Company included no recovery of costs related to the DEP Solar PV Facilities in its current REPS rider filing, and submitted that it has now met in full the cost recovery conditions of the CPCN Orders, and its compliance requirement is completed.

No party disputed whether DEP had complied with the required treatment of the costs related to the DEP Solar PV Facilities.

Based upon the foregoing and the entire record herein, the Commission finds that DEP appropriately calculated its avoided costs and incremental REPS compliance costs for the test period and the billing period. The Commission further finds that for the purpose of establishing the REPS EMF rider in this proceeding, DEP's incremental costs for REPS compliance during the test period were $42,744,260, including the costs incurred for DEP's Wholesale Customers, and that these costs were reasonable and prudently incurred. The Commission further finds that DEP appropriately projected incremental costs for REPS compliance for the billing period totaling $40,959,120, representing costs of compliance based on DEP's retail sales only, because DEP's obligation to provide REPS compliance services to the Wholesale Customers ended December 31, 2017. Therefore, the Commission concludes that DEP's request for recovery of these costs should be approved. In addition, the Commission finds that DEP has complied with the requirements of the CPCN Orders, as relevant to this proceeding. Therefore, the Commission concludes that DEP's compliance obligation related to the conditions detailed above is complete.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence for this finding of fact is found in DEP's Application and in the direct testimony and exhibits of DEP witness Williams, as well as in the affidavits of Public Staff witnesses Boswell and Lucas.

Witness Williams' direct testimony explained that incremental costs assigned to DEP retail customers are separated into two categories: costs related to solar, poultry and swine waste compliance requirements, and research, solar rebate program and other incremental costs (Set-Aside and Other Incremental Costs); and costs related to the General Requirement (General Incremental Costs). Set-Aside and Other Incremental Costs are allocated to customer class based on per-account cost caps, and General Incremental Costs are allocated among customer classes to give credit for EE RECs (EECs), for which there are no General Incremental Costs according to the relative energy reduction contributed by each customer class.

In his affidavit, Witness Lucas noted that the Commission, in its 2017 DEP REPS Order, required DEP and the Public Staff to evaluate the inputs and methods used to allocate credits for EECs by class, and file a report of the results. On April 12, 2018, the Public Staff and DEP filed the joint report as required in Docket No. E-2, Sub 1144. Witness Lucas stated in his affidavit in this current proceeding that the Public Staff reviewed the allocation method used by DEP in this rider proceeding, and agreed that it is consistent with the method agreed to by the Public Staff and DEP in the April 12, 2018, joint report. In her affidavit, Witness Boswell indicated the Public Staff recommended no adjustments to DEP's proposed allocation among customer classes for credits for EECs.

The Commission finds that DEP's allocation of incremental REPS compliance costs among customer classes for the purposes of calculating its proposed REPS and EMF rider components is appropriate for this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 16-21

The evidence for these findings of fact is found in the direct testimony and exhibits of DEP witnesses Jennings and Williams, including DEP's application for cost recovery, and in the affidavits of Public Staff witnesses Boswell and Lucas.

Williams Exhibit No. 2 demonstrates that DEP's total NC Retail test period under-collections were $2,124,217 for the residential class and $196,787 for the industrial class, and an over-collection, including interest, of $1,272,374 for the general service class. Williams Exhibit No. 4 shows additional credits for contract receipts by customer class of $325,340 for residential, $294,082 for general service, and $18,500 for industrial. Total under-collections net of contract-related credits by class for the EMF period are $1,798,877 for residential and $178,287 for industrial. The total over-collection including contract-related credits is $1,566,456 for the general service class. As reflected in Williams Exhibit No. 4, witness Williams calculated proposed NC Retail monthly per-account REPS EMF charges (excluding regulatory fee) of $0.12 for residential accounts and $8.11 for industrial accounts, and a monthly REPS EMF credit (excluding regulatory fee) of $(0.66) for general service accounts. Also in Williams Exhibit No. 4, she calculated the projected NC Retail REPS costs for the billing period of $19,004,704 for the residential class, $20,526,773 for the general service class, and $1,427,643 for the industrial class. Williams Exhibit No. 4 shows that the proposed monthly prospective REPS riders per customer account, excluding the regulatory fee, to be collected during the billing period are $1.30 for residential accounts, $8.61 for general service accounts, and $64.96 for industrial accounts. The combined monthly REPS and REPS EMF rider charges per customer account, excluding regulatory fee, to be collected during the billing period are thus $1.42 for residential accounts, $7.95 for general service accounts, and $73.07 for industrial accounts. Including the regulatory fee, the combined monthly REPS and REPS EMF rider charges per customer account to be collected during the billing period are $1.42 for residential accounts, $7.96 for general service accounts, and $73.17 for industrial accounts. As further illustrated on Williams Exhibit No. 4, the Company's REPS incremental cost rider to be charged to each customer account for the billing period is within the annual cost cap established for each customer class in N.C.G.S. § 62-133.8(h)(4).

Public Staff witness Boswell stated in her affidavit that as a result of its investigation, the Public Staff recommended that the Company's proposed annual REPS EMF increment/(decrement) amounts and monthly EMF riders for each customer class be approved. Witness Boswell also stated that, excluding the regulatory fee, the annual increment/(decrement) REPS EMF riders are $1.47, $(7.88) and $97.35 and the monthly increment/(decrement) REPS EMF riders are $0.12, $(0.66), and $8.11, per retail customer account, for residential, general service, and industrial customers, respectively.

Public Staff witness Lucas stated that the Public Staff had reviewed the costs that produced the proposed, revised rates and that it took no issue with them. He recommended approval of the Company's proposed monthly per account REPS rider charges for the combined REPS and EMF billing components for the billing period (including regulatory fee), as follows: $1.42 for residential accounts, $7.96 for general service accounts, and $73.17 for industrial accounts.

Based upon the foregoing and the entire record herein, the Commission finds that DEP's calculation of its incremental costs for compliance with the REPS requirements during the test period and incremental costs projected during the billing period, and the resulting monthly per-account REPS rider and REPS EMF rider charges as set out in Revised Williams Exhibit No. 4, are reasonable and appropriate. The Commission further finds that the total of these charges are well below the respective annual per-account cost limits of $34.00, $150.00, and $1,000.00, for residential, commercial/general service, and industrial customers, as established in G.S. 62-133.8(h)(4). Therefore, the Commission concludes that DEP's total over-collection amounts incurred during the Test Period and the costs projected to be incurred during the billing period and the resulting REPS EMF and REPS rider charges should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That DEP shall establish a REPS rider as described herein, in the amounts approved herein, and that this rider shall remain in effect for a twelve-month period beginning on December 1, 2018, and expiring on November 30, 2019;

2. That DEP shall establish an EMF rider as described herein, in the amounts approved herein, and that this rider shall remain in effect for a twelve-month period beginning on December 1, 2018, and expiring on November 30, 2019;

3. That DEP shall file the appropriate rate schedules and riders with the Commission in order to implement the provisions of this Order as soon as practicable, but not later than ten (10) days after the date that the Commission issues orders in this docket and in Docket Nos. E-2, Sub 1173 and E-2, Sub 1176;

4. That DEP shall work with the Public Staff to prepare a joint notice to customers of the rate changes ordered by the Commission in this docket, as well as in Docket Nos. E-2, Sub 1173 and E-2, Sub 1176, and the Company shall file such notice for Commission approval as soon as practicable, but not later than ten (10) days after the Commission issues orders in both dockets;

5. That DEP's 2017 REPS compliance report shall be, and is hereby, approved and the RECs in DEP's 2017 compliance sub-accounts in NC-RETS and those of the Wholesale Customers shall be retired;

6. That DEP shall file in all future REPS rider applications the results of studies the costs of which were or are proposed to be recovered through the REPS rider charges and, for those studies that are subject to confidentiality agreements, information regarding whether and how parties can access the results of those studies; and

7. That DEP shall continue to file a worksheet explaining the discrete costs it includes as "other incremental costs" in all future REPS Rider proceedings.

ISSUED BY ORDER OF THE COMMISSION.
This the 8th day of November, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. E-2, SUB 1176

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:

Application by Duke Energy Progress, LLC	)	
for Approval of Joint Agency Asset Rider	)	
for Recovery of Costs Related to Facilities	)	ORDER APPROVING JOINT
Purchased from Joint Power Agency	)	AGENCY ASSET RIDER
Pursuant to N.C. Gen. Stat. § 62-133.14	)	ADJUSTMENT
and Rule R8-70	)	

HEARD: Tuesday, September 18, 2018, at 10:00 a.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Charlotte A. Mitchell, Presiding; Chairman Edward S. Finley, Jr., Commissioner ToNola D. Brown-Bland, Commissioner Jerry C. Dockham, Commissioner James G. Patterson, Commissioner Lyons Gray, and Commissioner Daniel G. Clodfelter

APPEARANCES:

For Duke Energy Progress, LLC:

Lawrence B. Somers, Deputy General Counsel, Duke Energy Corporation, NCRH 20/Post Office Box 1551, Raleigh, North Carolina 27602-1551

For the Using and Consuming Public:

Heather D. Fennell, Staff Attorney, Public Staff, North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

For the Carolina Utility Customers Association, Inc.:

Robert F. Page, Crisp & Page, PLLC, 4010 Barrett Drive, Suite 205, Raleigh, North Carolina 27609

For the Carolina Industrial Group for Fair Utility Rates II:

Warren Hicks, Bailey & Dixon, LLP, Post Office Box 1351, Raleigh, North Carolina 27602

BY THE COMMISSION: On June 20, 2018, Duke Energy Progress, LLC (DEP or the Company) filed its Application for Approval of Joint Agency Asset Rider (JAAR) to recover costs related to facilities purchased from the North Carolina Eastern Municipal Power Agency (NCEMPA) pursuant to N.C. Gen. Stat. § 62-133.14 and Commission Rule R8-70. DEP's application was accompanied by the testimony and exhibits of LaWanda M. Jiggetts – Rates and Regulatory Strategy Manager. In its application and pre-filed testimony, DEP sought approval of the proposed rider, which incorporated the Company's proposed adjustments in its North Carolina retail rates.

On July 2, 2018, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice, in which the Commission set this matter for public witness and expert witness hearings, established discovery guidelines, and provided for public notice of the hearings.

On July 3, 2018, Carolina Industrial Group for Fair Utility Rates II (CIGFUR II) filed its petition to intervene. The Commission granted the petition on July 6, 2018. On July 19, 2018, Carolina Utility Customers Association, Inc. (CUCA) filed its petition to intervene. CUCA's petition was granted on July 24, 2018. The intervention and participation by the Public Staff is recognized pursuant to N.C. Gen. Stat. § 62-15(d) and Commission Rule R1-19(e).

On August 31, 2018, DEP filed the supplemental testimony and revised exhibits[1] of witness Jiggetts and a Motion for Additional Public Hearing and Public Notice of Revised Rates.

On September 4, 2018, the Public Staff filed the testimony of Darlene P. Peedin – Manager of the Electric Section of the Accounting Division of the Public Staff.

No other party pre-filed testimony in this docket.

On September 5, 2018, the Commission issued an Order Scheduling Additional Public Hearing and Requiring Public Notice.

On September 7, 2018, DEP and the Public Staff filed a Joint Motion to Excuse All Witnesses from appearing at the September 18, 2018 hearing in this proceeding. The Commission granted this motion on September 12, 2018.

On September 13, 2018, DEP filed its affidavits of publication for the initial public notice, and on October 5, DEP filed affidavits for the additional public notice.

This matter came on for hearing as scheduled on September 18, 2018. No public witnesses appeared. Because the parties had waived cross-examination of witnesses, DEP asked that the Company's application and the direct and supplemental testimony of witness Jiggetts be copied into the record and that her initial exhibits and revised exhibits be entered into evidence. The Commission granted those requests.

The Public Staff also moved into evidence the testimony of witness Peedin. That request was also granted. No other party presented witnesses.

The matter came on for hearing for an additional public witness hearing on October 8, 2018. No public witnesses appeared.

Based upon the foregoing, DEP's verified application, the testimony, supplemental testimony, initial exhibits, and revised exhibits received into evidence at the hearing, and the entire record in this proceeding, the Commission makes the following:

[1] DEP filed two revised exhibits to reflect changes to certain calculations from what was originally filed.

FINDINGS OF FACT

1. DEP is a duly organized corporation existing under the laws of the State of North Carolina, engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North Carolina and South Carolina, and is subject to the jurisdiction of the North Carolina Utilities Commission as a public utility. DEP is lawfully before this Commission based upon its application filed pursuant to N.C. Gen. Stat. § 62-133.14 and Commission Rule R8-70.

2. On July 31, 2015, DEP acquired NCEMPA's undivided ownership interests of 18.33% in the Brunswick Steam Electric Plant (Brunswick Units 1 and 2), 12.94% in Unit No. 4 of the Roxboro Steam Electric Plant (Roxboro Unit 4), 3.77% in the Roxboro Plant Common Facilities, 16.17% in the Mayo Electric Generating Plant (Mayo Unit 1), and 16.17% in the Shearon Harris Nuclear Power Plant (Harris Unit 1) (collectively, Joint Units). On May 12, 2015, the Commission issued an Order Approving Transfer of Certificate and Ownership Interests in Generating Facilities in Docket No. E-2, Sub 1067 and Docket No. E-48, Sub 8, which approved the transfer of NCEMPA's ownership interests in the Joint Units to DEP.

3. Pursuant to N.C. Gen. Stat. § 62-133.14, DEP is allowed to recover the North Carolina retail portion of all reasonable and prudent costs incurred to acquire, operate, and maintain the proportional interest in the generating facilities purchased from NCEMPA. Commission Rule R8-70(c) provides for an annual proceeding to establish the JAAR and requires the electric public utility to submit an application at the same time that it files the fuel proceeding information required by Commission Rule R8-55.

4. Commission Rule R8-70 schedules an annual adjustment hearing for DEP and requires that the Company use a test period of the calendar year that precedes the end of the test period used for purposes of Commission Rule R8-55. The test period covered by the proposed rates in this proceeding is January 1, 2017 through December 31, 2017. Pursuant to Commission Rule R8-70, each annual filing will provide for the recovery of costs expected to be incurred in the rate period (prospective component), including the levelized annual cost of the plant initially acquired and appropriate annual portions of the cost of other assets acquired (excluding construction work in progress), as well as ongoing annual non-fuel operating costs, reduced by the annual effects of the acquisition on North Carolina retail allocation factors. Commission Rule R8-70(b) provides for an over- or underrecovery component as a Rolling Recovery Factor, or a "Joint Agency Asset RRF," and requires the Company to use deferral accounting and maintain a cumulative balance of costs incurred but not recovered through the JAAR. This cumulative balance will accrue a monthly return as prescribed by the Rule.

5. DEP's proposed rates consist of a prospective component related to the future billing period December 2018 through November 2019, and a Joint Agency Asset RRF component that accomplishes the true-up of costs incurred through the test year ended December 31, 2017.

6. In its application and testimony in this proceeding, as revised, DEP requested a total of $147.654 million for the prospective component of its North Carolina retail revenue

requirement, for the period December 1, 2018 through November 30, 2019, associated with the acquisition and operating costs of NCEMPA's undivided ownership interest in the Joint Units.

7. The annual levelized costs associated with the acquisition of the Joint Units at the time of purchase were $56.314 million. DEP also requested an additional $8.276 million in annual pre-tax costs associated with the acquisition costs not included in the levelized costs. The acquisition costs underlying these amounts are deemed reasonable and prudent under N.C. Gen. Stat. § 62-133.14(b)(1).

8. DEP requested an additional $12.473 million in annual financing and operating costs relating to estimated capital additions during the rate period. The Commission finds it reasonable for the Company to recover these estimated costs during the rate period, subject to true-up through the Joint Agency Asset RRF.

9. DEP estimates the annual non-fuel operating costs from December 1, 2018 to November 30, 2019 to be $70.385 million. The Commission finds it reasonable for the Company to recover these estimated costs during the rate period, subject to true-up through the Joint Agency Asset RRF.

10. DEP requested $0.207 million for incremental regulatory fees. The Commission finds it reasonable for the Company to recover these estimated costs during the rate period, subject to true-up through the Joint Agency Asset RRF.

11. The prospective annual revenue requirement of $147.654 million resulting from the summing of the amounts set forth in Findings of Fact Nos. 7 through 10 has not been reduced by the annual effects of the acquisition on North Carolina retail allocation factors. This prospective credit is no longer applicable in the JAAR as new North Carolina retail base rates were effective March 16, 2018, as established in DEP's general rate case in Docket No. E-2, Sub 1142. North Carolina retail base rates approved in Sub 1142 reflect greater costs being allocated to wholesale customers because the Company is now supplying the entire electric requirements for NCEMPA.

12. In addition to the prospective components, DEP requests to return $9.196 million in its application and testimony in this proceeding through the Joint Agency Asset RRF component of its North Carolina retail revenue requirement charged during the period December 1, 2018 through November 30, 2019, related to the overrecovery of financing and non-fuel operating costs experienced through the test year ended December 31, 2017. The Commission finds the actual costs and credits underlying this true-up amount to be reasonable and prudent for purposes of this proceeding, and the return of this amount to be reasonable and appropriate.

13. Under N.C. Gen. Stat. § 62-133.14(b)(5), the prospective components and Joint Agency Asset RRF have been allocated under the customer allocation methodology approved by the Commission in Docket No. E-2, Sub 1142, DEP's most recent general rate case, to produce the following rates by customer class, which rates the Commission finds to be just and reasonable.

Rate Class	Applicable Schedule(s)	Prospective Rate	Rolling Recovery Factor	Combined Rate*
Non-Demand Rate Class (dollars per kilowatt-hour)				
Residential	RES, R-TOUD, R-TOUE, R-TOU	0.00456	(0.00015)	0.00441
Small General Service	SGS, SGS-TOUE	0.00542	(0.00044)	0.00498
Medium General Service	CH-TOUE, CSE, CSG	0.00411	(0.00039)	0.00372
Seasonal and Intermittent Service	SI	0.00412	0.00037	0.00449
Traffic Signal Service	TSS, TFS	0.00248	(0.00011)	0.00237
Outdoor Lighting Service	ALS, SLS, SLR, SFLS	-	-	-
Demand Rate Classes (dollars per kilowatt)				
Medium General Service	MGS, GS-TES, AP-TES, SGSTOU	1.35	(0.18)	1.17
Large General Service	LGS, LGS-TOU	1.38	(0.02)	1.36

*Incremental Rates, shown above, include North Carolina regulatory fee of 0.14%.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This Finding of Fact is essentially informational, procedural, and jurisdictional in nature and is uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 2-4

The evidence for these Findings of Fact can be found in DEP's application, N.C. Gen. Stat. § 62-133.14, and Commission Rule R8-70.

Under N.C. Gen. Stat. § 62-133.14(a), upon the filing of a petition of an electric public utility and a public hearing, the Commission is required to approve an annual rider to the utility's rates for the North Carolina retail portion of reasonable and prudent costs incurred to acquire, operate and maintain the Joint Units. The acquisition costs shall be deemed reasonable and prudent and shall be levelized over the useful life of the Joint Units at the time of acquisition. Financing costs shall be included and shall be equal to the weighted average cost of capital as authorized in the utility's most recent general rate case.

The utility may recover an estimate of operating costs based on the experience of the test period and the costs projected for operation of the Joint Units for the next twelve months, subject to the filing of an annual adjustment including any under- or overrecovery, any changes necessary to recover costs for the next twelve-month period, or any changes to the cost of capital or customer allocation methodology occurring in a general rate case after the establishment of the initial rider. Commission Rule R8-70(c) requires the Company to propose annual updates to its JAAR in order for the hearing to be held as soon as practicable after the hearing held by the Commission under Rule R8-55.

The Commission concludes that DEP's application is in compliance with N.C. Gen. Stat. § 62-133.14 and Commission Rule R8-70.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-7

The evidence for these Findings of Fact can be found in the direct testimony of DEP witness LaWanda M. Jiggetts and in the testimony of Public Staff witness Darlene P. Peedin.

Witness Jiggetts' exhibits reflect that DEP's annual levelized cost associated with the acquisition price of the Joint Units was $56.314 million. In her direct testimony, witness Jiggetts explained that the Company seeks to recover its acquisition costs, which are the amounts DEP paid to NCEMPA to acquire the proportional ownership interest in the Joint Units, including the amount paid above the net book value of the facilities. Within this first category of acquisition costs there are also two subgroups: costs for which the recovery is levelized and costs for which the recovery is not levelized. In general terms, the levelized revenue requirement represents recovery of the acquisition cost for the NCEMPA assets, spread evenly over the remaining life of the assets at the time the Joint Units were purchased. Witness Jiggetts also included additional financing and operating costs of $8.276 million associated with assets purchased that were not included as part of the levelized costs. In her direct testimony, witness Jiggetts described these costs as including inventory amounts that are part of the asset acquisition costs, nuclear fuel inventory, dry cask storage, and materials and supplies inventory. Because these assets are not depreciated, the financing costs for these amounts are calculated on the basis of the average investment for the rate period.

Pursuant to N.C. Gen. Stat. § 62-133.14(b)(2), the JAAR shall include financing costs equal to the weighted average cost of capital as authorized by the Commission in the electric public utility's most recent general rate case. Witness Jiggetts' exhibits reflect that the Company computed the debt and equity rate of return and the Company's weighted average net-of-tax cost of capital as authorized by the Commission in DEP's most recent general rate case. The net of tax cost of capital incorporates the 3% North Carolina state income tax rate that became effective January 1, 2017.

In her testimony filed with the Commission, Public Staff witness Peedin stated that the Public Staff's investigation included a review of DEP's application, testimony, and exhibits filed in this docket. Additionally, the Public Staff's investigation included the review of responses to written and verbal data requests, as well as discussions with the Company. She further testified that the Public Staff performed a limited review of the underlying capital additions and operating costs added to the calculation of the rider in this proceeding and did not perform a full-scale review of the prudence and reasonableness of all such additions or expenses. She testified that Commission Rule R8-70(b)(4) provides that the Commission is to determine the reasonableness and prudence of the cost of capital additions or operating costs incurred related to the acquired plant in a general rate proceeding. However, should the Public Staff discover imprudent or unreasonable costs in a JAAR proceeding, it will recommend an adjustment in that proceeding; in that case, it would also recommend that the impact of any disallowance also be reflected in the Company's cost of service in a general rate case. She testified the Public Staff did not find any adjustments that should be made to the calculations of either the prospective or Joint Agency Asset RRF revenue requirements.

Based on the evidence on the record, the Commission concludes that, pursuant to N.C. Gen. Stat. § 62-133.14(b)(1), DEP is allowed to recover in the annual JAAR the financing and depreciation costs associated with the acquisition costs of the Joint Units on a levelized basis in the amount of $56.314 million annually, and the annual amount of $8.276 million of financing and operating costs associated with acquisition costs that are not levelized. To the extent the costs underlying these amounts are acquisition costs, such costs are deemed reasonable and prudent under N.C. Gen. Stat. § 62-133.14(b)(1). The Commission further finds it reasonable for the Company to recover the remainder of these estimated costs during the rate period, subject to true-up through the Joint Agency Asset RRF.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8-9

The evidence for these Findings of Fact can be found in DEP's application, the testimony of DEP witness LaWanda M. Jiggetts and the testimony of Public Staff witness Darlene P. Peedin.

The Company requested annual costs of $12.473 million to be included in the JAAR for financing and operating costs related to estimated capital additions to be incurred during the period December 1, 2018 through November 30, 2019, and an estimated $70.385 million for annual non-fuel operating costs over the period December 1, 2018 to November 30, 2019. Under N.C. Gen. Stat. § 62-133.14(b)(3), the Commission shall include in the rider an estimate of operating costs based on the prior year's experience and the costs projected for the next twelve months, and shall include the annual financing and operating costs for any proportional capital investments in the acquired electric generation facility. Public Staff witness Peedin did not oppose the recovery of these cost components in her testimony filed in this proceeding, and stated that the Public Staff recommended approval of the Company's revised proposed JAAR rates. The Commission concludes that it is reasonable for the Company to recover these estimated costs during the rate period, subject to true-up through the Joint Agency Asset RRF.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence for this Finding of Fact can be found in the testimony of DEP witness Lawanda M. Jiggetts.

Witness Jiggetts' exhibits reflected a decrease in DEP's regulatory fee to $0.207 million based on the decrease in the estimated JAAR costs for the period December 1, 2018 through November 30, 2019. The Commission concludes that the calculation of the regulatory fee is just and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence for this Finding of Fact can be found in DEP's application and the testimony of DEP witness LaWanda M. Jiggetts, as well as the testimony of Public Staff witness Darlene P. Peedin.

Under N.C. Gen. Stat. § 62-133.14(b)(4), the JAAR shall include adjustments to reflect the North Carolina retail portion of financing and operating costs related to the electric public utility's other used and useful generating facilities owned at the time of the acquisitions to properly account for updated jurisdictional allocation factors. This adjustment benefits DEP customers by reducing DEP's annual retail revenue requirement. Witness Jiggetts testified that the revenue reductions reflect changes in jurisdictional allocation factors resulting from the additional NCEMPA load that will be served by the Company's portfolio of generating facilities owned at the time of the acquisition. As a consequence, a greater portion of the cost of the Company's other generating facilities will be allocated to its wholesale jurisdiction, while a lesser portion will be allocated to its retail jurisdictions. In her direct testimony, witness Jiggetts testified that in the Company's filing, the annual revenue reduction to North Carolina retail revenue requirements for the test period January 2017 through December 2017 totaled $87 million. For the prospective period December 2018 through November 2019, the reduction is zero. Witness Jiggetts testified that the change in allocation approach was due to the Company's base rate request filed in Docket No. E-2, Sub 1142. The reallocation between retail and wholesale jurisdictions is reflected in the base rates approved by the Commission in Docket No. E-2, Sub 1142. Therefore the reduction will not be included in JAAR revenue requirements from March 16, 2018 forward, the effective date for DEP's new base rates.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence for this Finding of Fact can be found in DEP's application, the direct testimony of DEP witness LaWanda M. Jiggetts, DEP's exhibits to the JAAR, and the testimony of Public Staff witness Darlene P. Peedin.

The Company requested a Joint Agency Asset RRF decrement adjustment of $9.196 million related to the overrecovery of costs incurred through the test year ended December 31, 2017. The Commission notes that DEP should file a Joint Agency Asset RRF adjustment rider to include a true-up between estimated and actual costs incurred during the test period under N.C. Gen. Stat. § 62-133.14(c). The deferred costs related to any true-up are to be recorded as a regulatory asset or regulatory liability, including a return on the deferred balance each month. Public Staff witness Peedin did not oppose the return of this rate component in her testimony filed in this proceeding. The Commission finds the actual costs and credits underlying this true-up amount to be reasonable and prudent, and that the return of this amount is reasonable and appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence for this Finding of Fact can be found in DEP's application, the direct testimony and supplemental testimony of DEP witness LaWanda M. Jiggetts, DEP's revised exhibits, and the testimony of Public Staff witness Darlene P. Peedin.

Pursuant to N.C. Gen. Stat. § 62-133.14(b)(5), the costs of the rider shall be allocated utilizing the cost allocation methodology approved in DEP's last general rate case, Docket No. E-2, Sub 1142. In her direct testimony, witness Jiggetts testified that the Company's filing used the customer allocation methods approved in DEP's last general rate case. The North Carolina retail revenue requirement was allocated among customer classes using the production demand allocation factors. For the prospective revenue requirement, rates were set for each customer class. For the Joint Agency Asset RRF rates, production demand was used to split the revenue requirement between two customer groups, customers billed by kW and customers billed by kWh. This approach resulted in one common rate being applied to all customer classes within the respective group.

In her supplemental testimony, witness Jiggetts testified that the Company revised its approach to calculate the rates associated with the Joint Agency Asset RRF, based on the Public Staff's inquiries regarding the methodology used in developing uniform rates for the two customer groups. Instead of using a common rate for the two customer groups, rates were established for each North Carolina retail customer class based on the over/under collection position using production demand allocation factors. Witness Jiggetts also testified that the total revenue requirement did not change as a result of this revision due to the fact that the total dollars needed for the Rolling Recovery Factor were not impacted. The revision only impacts how the Rolling Recovery Factor is recovered between different rate classes of North Carolina retail customers. The table included in Finding of Fact No. 13 sets forth the revised rates.

The Company agreed with Public Staff witness Peedin's recommendation regarding the usage of the production demand allocation factors to set rates for each of the North Carolina retail customer classes. Witness Peedin agreed with the revised RRF on a class-specific basis as opposed to the uniform rates that are initially proposed. The class specific calculation for the Joint Agency RRF conforms with DEP's approved customer allocation methodology set forth in the most recent general rate case.

Based on the evidence and the record, the Commission finds and concludes that the rates set forth in the table included in Finding of Fact No. 13 are just and reasonable.

IT IS, THEREFORE, ORDERED as follows:

1. That DEP shall be allowed to charge in a rider $138.458 million ($147.654 million as the prospective component and ($9.196) million in the Joint Agency Asset RRF) on an annual basis to recover the costs in relation to the acquisition and operation of the Joint Units;

2. That the costs shall be allocated using the customer allocation methodology used in DEP's last general rate case as shown in DEP's application and the supplemental testimony of DEP witness Jiggetts;

3. That DEP shall file appropriate rate schedules and riders with the Commission in order to implement these approved rate adjustments to be effective for service rendered on and after December 1, 2018, as soon as practicable; and,

4. That DEP shall work with the Public Staff to jointly prepare a proposed notice to customers of the rate adjustments ordered by the Commission in Docket Nos. E-2, Subs 1173, 1175, and 1176 and the Company shall file the proposed notice to customers for Commission approval as soon as practicable.

ISSUED BY ORDER OF THE COMMISSION.
This the 8th day of November, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

ONE-HUNDRED EIGHTH REPORT

OF THE

NORTH CAROLINA

UTILITIES COMMISSION

ORDERS AND DECISIONS

Volume III

ISSUED FROM
JANUARY 1, 2018 THROUGH DECEMBER 31, 2018

ONE-HUNDRED EIGHTH REPORT
of the
NORTH CAROLINA UTILITIES COMMISSION

ORDERS AND DECISIONS

Issued from

January 1, 2018, through December 31, 2018

Edward S. Finley, Jr., Chairman

*Bryan E. Beatty, Commissioner

ToNola D. Brown-Bland, Commissioner

Jerry C. Dockham, Commissioner

James G. Patterson, Commissioner

Lyons Gray, Commissioner

Daniel G. Clodfelter, Commissioner

*Charlotte A. Mitchell

North Carolina Utilities Commission
Office of the Chief Clerk
M. Lynn Jarvis
4325 Mail Service Center
Raleigh, North Carolina 27699-4325

The Statistical and Analytical Report of the North Carolina Utilities Commission is printed separately from the volume of Orders and Decisions and will be available from the Office of the Chief Clerk of the North Carolina Utilities Commission upon order.

*Charlotte A. Mitchell was sworn in on January 26, 2018, replacing Bryan E. Beatty.

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DOCKET NO. EC-23, SUB 50

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Blue Ridge Electric Membership Corporation, Complainant, v. Charter Communications Properties, LLC, Respondent.	)))))))))))	ORDER RESOLVING POLE ATTACHMENT COMPLAINT PURSUANT TO NORTH CAROLINA GENERAL STATUTE § 62-350

HEARD: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, November 8-9, 2017 and December 18, 2017

BEFORE: Chairman Edward S. Finley, Jr., Presiding, and Commissioners Bryan E. Beatty, ToNola D. Brown-Bland, Jerry C. Dockham, James G. Patterson, and Daniel G. Clodfelter

APPEARANCES:

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BY THE COMMISSION: This is the fifth pole attachment case to come before the Commission under the jurisdiction provided in the General Assembly's 2015 amendments to North Carolina General Statute § 62-350 (N.C. Gen. Stat. § 62-350).

N.C. Gen. Stat. § 62-350 gives exclusive jurisdiction to the Commission to resolve disputes between municipally-owned and cooperatively organized utilities and communications service providers, defined to include telephone companies, telephone membership corporations (TMCs), broadband service providers, and cable operators. Municipal and cooperative utilities are required to allow communications service providers to use their poles, ducts and conduits at "just, reasonable, and nondiscriminatory rates, terms and conditions adopted pursuant to negotiated or adjudicated agreements." N.C. Gen. Stat. § 62-350(a). Where disputes between pole owners and attaching communications service providers are not resolved within a 90-day period, or where either party believes in good faith that they are at an impasse, either party may bring a complaint to the Commission for resolution. The Commission has exclusive jurisdiction over the dispute, and is required to adjudicate all such complaints on a case-by-case basis. N.C. Gen. Stat. § 62-350(c). With respect to rate issues, the Commission is granted discretion to "consider any evidence or rate-making methodologies offered or proposed by the parties . . . consistent with the public interest." Id. In particular, the law makes clear that the Commission "may consider any evidence presented by a party, including any methodologies previously applied." N.C. Session Law 2015-119, § 7. Any new rate adopted by the Commission is applied retroactively to the date of initiation of the proceeding or "the date immediately following the expiration of the 90-day negotiating period, whichever is earlier." N.C. Gen. Stat. § 62-350(c). If the rate relates to an existing agreement, however, the new rate "applies retroactively to the date immediately following the end of the existing agreement." Id.

In addition to setting forth a process to resolve disputes regarding rates and terms of attachment, N.C. Gen. Stat. § 62-350 separately addresses safety and compliance issues. The statute provides that, in the absence of a different agreement between the parties, if the facilities of a communications service provider do not comply with applicable safety rules and regulations, the electric membership corporation (EMC) or municipal utility must follow a prescribed procedure for notifying the communications service provider, making a demand that the compliance issues be cured, and working together "cooperatively to determine the causation of, and to effectuate any remedy for, noncompliant lines, equipment, and attachments." Id. N.C. Gen. Stat. § 62-350(d).

Finally, in N.C. Gen. Stat. § 62-350, the General Assembly directed the Commission to "adjudicate disputes arising under this [statute] on a case-by-case basis." N.C. Gen. Stat. § 62-350(c). As a consequence of these directives, any decision reached in this docket regarding the rate, and/or the ratemaking methodology or the terms and conditions which govern these parties' pole attachment agreement will be based upon the unique facts and circumstances present in this docket. Furthermore, in each subsequent pole attachment dispute that is filed with the Commission, the Commission will be required to examine the unique facts and circumstances in that case and to make its decision based upon those unique facts and circumstances as a consequence of these directives. As a result, the Commission's ultimate decision in this docket will not and cannot establish a binding precedent in future pole attachment resolution proceedings with regard to core and salient issues raised by and addressed in this docket.

On November 30, 2016, Blue Ridge Electric Membership Corporation (Blue Ridge or the Complainant), an electric cooperative utility organized under Chapter 117 of the General Statutes, filed a Complaint (the Complaint) against Charter Communications Properties, LLC (Charter), a "communications services provider" as defined in N.C. Gen. Stat. § 62-350. Blue Ridge's Complaint alleged that Charter had improperly refused to agree to reasonable terms and conditions in a new pole attachment agreement, including a pole attachment rate.

On February 1, 2017, Charter filed its Answer to Blue Ridge's Complaint. In its Answer, Charter responded to the allegations of the Complaint and also sought additional relief against Blue Ridge in a Counterclaim. On March 1, 2017, Blue Ridge filed its Answer to Charter's Counterclaim.

On May 26, 2017, Blue Ridge filed a motion for a procedural schedule. Charter responded on May 31, 2017. The Chairman issued an order to establish a procedural schedule on June 7, 2017.

On August 8, 2017, Blue Ridge and Charter filed a joint motion to approve a stipulated protective agreement, which the Chairman granted by order dated August 10, 2017.

On September 12, 2017, Blue Ridge filed a motion for leave to amend its Complaint, and on September 18, 2017, filed a motion to compel discovery from Charter. Also, on September 18, 2017, Charter filed a motion for a temporary stay and in opposition to Blue Ridge's motion for leave to amend its Complaint. Blue Ridge opposed Charter's motion for a temporary stay and replied to Charter's opposition to its motion to amend its Complaint on September 21, 2017. Charter in turn replied in support of its motion for a temporary stay on September 22, 2017. On September 27, 2017, the Chairman issued an order granting Blue Ridge leave to amend its Complaint and denying the motion for a temporary stay.

On September 29, 2017, Charter filed its opposition to Blue Ridge's motion to compel discovery.

On October 3, 2017, Blue Ridge and Charter filed a joint motion for modification of the procedural schedule, that the Chairman granted by order dated October 6, 2017.

On October 9, 2017, the Chairman issued an order requiring Charter to submit an answer to Blue Ridge's Amended Complaint, and Charter filed the answer on October 16, 2017. The Chairman also issued an order on that date requiring the parties to make various pre-trial filings, including: (1) agreed upon stipulations covering all relevant and material facts, legal issues and factual issues; (2) contentions covering matters which the parties had not been able to stipulate; (3) a clear and concise listing and statement of each issue in dispute; (4) a list of the names and addresses of all witnesses each party may offer at trial, together with a brief statement of what counsel proposed to establish by their testimony; and (5) a list of exhibits which each party may offer at trial. These filings were duly submitted by the parties on November 2, 2017.

On October 16, 2017, Blue Ridge filed direct testimony of Wilfred Arnett, Gregory Booth, and Lee Layton. On October 31, 2017, Charter filed responsive testimony of Michael Mullins, Nestor Martin, and Patricia Kravtin. On November 1, 2017, Blue Ridge filed a notice of its objection to untimely filing and moved to supplement its rebuttal testimony at the hearing. Charter opposed this motion on November 3, 2017. Blue Ridge submitted rebuttal testimony of witnesses Arnett, Booth, and Layton on November 6, 2017. Blue Ridge replied to Charter's opposition to its motion to supplement its rebuttal testimony on November 7, 2017, and the Chairman, at the hearing, issued an oral ruling on Blue Ridge's motion by stating that Blue Ridge's counsel could ask their rebuttal witnesses additional questions when they took the stand. [Tr. Vol. 1, p.11].

The matter came on for hearing as scheduled on November 8 and 9, 2017, and concluded on December 18, 2017. Blue Ridge presented direct testimony, rebuttal testimony, and exhibits of witnesses Layton, Arnett and Booth. Charter offered responsive testimony and exhibits of witnesses Mullins, Martin and Kravtin.

On January 24, 2018, Charlotte Mitchell, counsel for Blue Ridge, moved to withdraw from the case following her appointment to the North Carolina Utilities Commission. The Chairman granted her motion the same day.

Pursuant to order of the Chairman at the conclusion of the hearing, post-hearing proposed orders and briefs were to be filed thirty (30) days from the filing of the last transcript. [Tr. Vol. 5, p. 155].

On February 14, 2018, Blue Ridge filed a motion to extend time to submit post-hearing briefs and proposed orders to April 4, 2018. On February 19, 2018, the Commission granted Blue Ridge's motion.

Blue Ridge and Charter filed briefs and proposed orders in accordance with the Order. Also, on that date, the North Carolina Association of Electric Cooperatives (NCAEC), the North Carolina Cable Telecommunications Association (NCCTA), the North Carolina Telephone Membership Cooperative Coalition (CarolinaLink), and Carolina Telephone and Telegraph Company LLC d/b/a CenturyLink, Central Telephone Company d/b/a CenturyLink and MebTel, Inc. d/b/a CenturyLink (collectively, CenturyLink) filed motions to participate in the proceeding as Amicus Curiae or, in the case of CenturyLink, a letter. On May 4, 2018, the Chairman granted the requests. Briefly summarized, the Amici comments are as follows.

Post-Hearing Amicus Briefs

NCAEC: NCAEC noted that it is a non-profit affiliate of the NCEMC charged with representing the common interest of its members (all 26 EMCs headquartered in North Carolina) including Blue Ridge. NCAEC commented that by law, EMCs must make electric service available to customers at the lowest cost consistent with sound economy and prudent management.

NCAEC stated that Charter is asking the Commission to adopt the Federal Communications Commission (FCC) rate methodology. According to NCAEC, properly determining just and reasonable pole attachment rates requires the Commission to address the FCC's rates shortcomings by considering the full range of potential rate methodologies, based on how parties actually use space on the poles. It also requires the Commission to weigh cable companies' false promises of rural broadband against the public's overriding interest in ensuring EMCs' members are not being forced to subsidize the operations of for-profit cable companies through electric rates. Additionally, NCAEC stated that the Commission should refuse Charter's demand that it consider only the subsidization of broadband and nothing else when it sets rates that are consistent with the public interest.

NCAEC stated that as the Commission considers the various rate methodologies discussed in this proceeding, the Commission should be mindful that the FCC Methodology rate is the clear wrong answer. NCAEC argued that the Tennessee Valley Authority (TVA) methodology represents a fairer and more reasonable way to divide the costs of the pole and reflects a proper understanding of the ways in which the parties use the pole and allocates the entire Communications Worker Safety Zone equally among communications attachers (but not the electric utility) and allocates the Support Space among all attaching entities on an equal, per capita basis.

Finally, NCAEC observed that the Commission's decision in this proceeding is not a binary choice and that Blue Ridge offered several alternative methodologies which the Commission is entitled to consider including the American Public Power Association (APPA) Rate, the Telecom Plus Rate and the Arkansas Formula. NCAEC also observed that the Commission is free to modify the space allocation factor contained in the proposed methodology to conform to the Commission's understanding of what would constitute a just and reasonable rate, consistent with the public interest and the parties' actual use of the poles.

<u>CarolinaLink</u>: CarolinaLink asserted that the TVA rate approach is a recent innovation designed to inflate rates certain electric suppliers can charge for access to their facilities. CarolinaLink argued that the TVA rate methodology is flawed for several reasons. CarolinaLink maintained that it is inappropriately based on the benefits received by the attacher, as opposed to the cost incurred by the pole owner. In addition, CarolinaLink maintained that even if it was appropriate to base the rate on benefits as opposed to costs, which it is not, the TVA rate wrongly assumes the attachers and pole owners benefit equally from the pole. CarolinaLink argued that they do not benefit equally and that a pole owner realizes a greater benefit from the pole because it owns the poles, designs the network with its needs in mind, and dictates the location of the attachment. CarolinaLink noted that while telecommunication and cable companies have a right to attach their facilities to utility poles, they do not have the right to exert the same control over the poles as the pole owner, nor do they have the right or as many opportunities to monetize the utility pole as the pole owner. Therefore, CarolinaLink asserted, pole owners receive more benefits from their poles than attachers.

CarolinaLink stated that long-established economic principles demonstrate that pole attachments should be based on costs rather than benefits or arbitrary and subjective value of service concepts. CarolinaLink noted that while the TVA formula appears to attribute the cost of the pole between the attachers and pole owner, in reality its cost allocation formula is based on the faulty notion that attachers and the pole owners each receive an equal benefit. CarolinaLink maintained that cost allocation, as the name suggests, should only be based on cost-causation and that the Commission is familiar with the concept of cost allocation. CarolinaLink maintained that direct costs are easily assigned because they are incurred incrementally to benefit a certain group. CarolinaLink noted that in addition to direct costs, there are always common costs, which must be assigned on a rational, economically efficient basis. CarolinaLink noted that common costs are allocated based on a reasonable allocator, which recognizes that a percentage of the common costs must be apportioned. CarolinaLink asserted that in approving cost allocation methodologies, the Commission does not assign common costs by an arbitrary method that selects who will be the winner and who will be the loser, totally disregarding the issue of cost causation.

CarolinaLink also noted that the EMCs' monopolistic control over poles in their service areas becomes increasingly problematic as some of the EMCs choose to enter the broadband market. CarolinaLink asserted that the EMCs should not be permitted to inflate the costs to potential competitors by artificially allocating unnecessary costs to those competitors or by arbitrarily assigning a value of service component to serve their own purposes.

CarolinaLink maintained that the FCC rate methodology has withstood the test of time. CarolinaLink also noted that as recently as July 31, 2017, the United States Court of Appeals for the Eighth Circuit stated that the FCC Cable Rate formula represents a reasonable policy choice.

CarolinaLink asserted that the FCC Cable Rate formula approximates an efficient rental rate that corresponds to the actual cost of the unit of service being produced. CarolinaLink noted that if pole attachments were in a competitive market in which a surplus could exist, the price would be driven down to its marginal costs. CarolinaLink argued that the FCC Cable Rate formula provides the pole owner with more than just its marginal costs and fairly compensates the pole owner for all out-of-pocket expenses, such as make-ready cost inspection fees, pole inventories, and other charges.

CarolinaLink noted that pole attachment rates are not only important to Investor Owned Utilities (IOUs), the rates are important to TMCs. CarolinaLink stated that, in many instances, the TMCs share many of the same characteristics with the EMCs; they are both member owned, are both organized under Chapter 117, both serve rural North Carolina with essential services, and are both operated for the benefit of their members. CarolinaLink maintained that the TMCs have differed with Charter on many public policy issues and in most cases have sided with the EMCs; however, in this limited instance, the TMCs share more in common with Charter than the EMCs and the EMCs share more in common with investor owned utilities than the TMCs.

CarolinaLink noted that, all combined, the EMCs serve a significant amount of territory, 2.5 million members spread through 93 North Carolina counties, and the EMCs overlap the TMCs almost entirely.

CarolinaLink also noted that rural broadband deployment continues to be a critical issue at the state and federal level. CarolinaLink asserted that the most problematic areas for broadband deployment are in rural areas and often in areas served by EMCs. CarolinaLink argued that broadband is a must for economic success in rural communities and that if EMC's are allowed to implement artificially high pole attachment rates investment in broadband will further shift away from rural areas and that those areas will continue to be left behind.

CenturyLink: CenturyLink stated that it was filing a letter to express support for the positions advocated by Charter. CenturyLink observed that like Charter, it relies on existing utility networks owned by electric and telephone utilities to provide services. Further, CenturyLink noted that excessive rates and burdensome contract terms are a concern of all pole attaching entities and that access to utility poles at just, reasonable and non-discriminatory rates is essential to the expansion of broadband and other advanced services across North Carolina, especially the rural areas which may be unserved or underserved. Pole attachment fees can be one of the largest costs in reaching rural customers and are a key component in determining how and where advanced services can be deployed. Finally, CenturyLink urged the Commission to consider the comments that CenturyLink made in its Amicus Brief in the prior pole attachment proceedings and incorporate those comments by reference into this proceeding.

NCCTA: NCCTA stated that the fundamental issue presented in this proceeding relates to the interpretation of N.C. Gen. Stat. § 62-350. According to NCCTA this is the same basic issue addressed by the Commission in prior pole attachment proceedings. NCCTA asserted that the orders issued in the prior proceedings were well reasoned, in the public interest, and in accord with the statutory requirement of N.C. Gen. Stat. § 62-350. Further, NCCTA urged the Commission to apply the same principles in the present proceeding and apply the FCC pole attachment rate methodology which is widely accepted, time-tested, and best suited for balancing the interests at stake. Finally, NCCTA urged the Commission to consider the comments that it made in its Amicus Brief in the prior pole attachment proceedings and incorporate those comments by reference into this proceeding.

Based on the foregoing, Blue Ridge's Complaint, Charter's Counterclaim and Answers and other filings, the evidence and exhibits presented at the hearing, and the entire record in this proceeding, the Commission now makes the following findings of fact and conclusions of law.

FINDINGS OF FACT

1. Charter and Blue Ridge entered into a pole attachment agreement as of September 1, 2008 (the 2008 Agreement). The 2008 Agreement expired on September 1, 2013.

2. A true and correct copy of the 2008 Agreement is attached as Exhibit No. LL-3 to the Direct Testimony of witness Layton.

3. Blue Ridge approached Charter about a new pole attachment agreement on May 22, 2014, noting that the 2008 Agreement had expired and offering a new draft agreement. [MM Ex. 2] On May 26, 2015, Charter sent a redlined draft agreement back to Blue Ridge. Despite negotiation efforts, the parties have not been able to resolve their differences regarding the rates, terms and conditions for a new agreement.

4. On or about June 22, 2015, the parties agreed to operate under the terminated 2008 Agreement until the General Assembly completed action on the revisions to

N.C. Gen. Stat. § 62-350. [MM Ex. 4] Charter attaches and has attached to Blue Ridge's poles pursuant to the 2008 Agreement.

5. The Commission has exclusive jurisdiction under N.C. Gen. Stat. § 62-350 to determine the just and reasonable rates that Blue Ridge may charge Charter for attaching its facilities to Blue Ridge's poles.

6. The Commission has exclusive jurisdiction under N.C. Gen. Stat. § 62-350 to determine the appropriate terms and conditions for Charter's continued use of or attachment to the poles, ducts, or conduits owned or controlled by Blue Ridge, including matters customary to such negotiations, such as a fair and reasonable rate for the use of facilities, indemnification by the attaching entity for losses caused in connection with the attachments, and the removal, replacement, or repair of installed facilities for safety reasons.

7. Charter and Blue Ridge each discussed at the hearing numerous state and federal decisions, and rate methodologies and methods which have been developed and/or applied by various state commissions, energy and communications related interest groups, organizations and federally established regulatory and administrative agencies.

8. Although Charter and Blue Ridge discussed at hearing various rate methodologies and methods, Charter and Blue Ridge each advocated that the Commission adopt specific, separate and distinct methodologies to determine the just and reasonable pole attachment rate that should be applied to resolve the dispute in this case.

9. Charter contended that the Commission should apply the FCC Cable Rate Methodology (FCC Rate Methodology) which was developed by the FCC, an administrative agency created by the federal government.

10. Blue Ridge compared the TVA methodology (TVA Rate Methodology) that was developed by the TVA, an administrative agency created by the federal government, to a number of other potential rate formulas, including the formula adopted by the American Public Power Association, the Telecom Plus formula considered by the United States House of Representatives, the formula adopted by the Arkansas Public Service Commission and the FCC Rate Methodology. After doing so, Blue Ridge contended that the TVA Rate Methodology was the proper formula for the Commission to apply to determine the just and reasonable rates that Charter should pay to attach to Blue Ridge's poles.

11. Neither the FCC nor the TVA has regulatory authority over the pole attachment rates charged by Blue Ridge.

12. While the Commission is not required under N.C. Gen. Stat. § 62-350 to apply the FCC Rate Methodology, the TVA Rate Methodology or any other rate methodologies discussed by the parties in deciding on the just and reasonable rates that should apply under the facts of this case, the Commission, in its discretion, may consider any evidence or rate-making methodologies offered or proposed by the parties to arrive at its decision as to the just and reasonable rates that Blue Ridge is authorized to charge Charter.

13. It is therefore appropriate for the Commission to consider both the FCC Rate Methodology and the TVA Rate Methodology in making its decision as to the maximum just and reasonable rates that Blue Ridge may charge Charter to attach to its poles.

14. The FCC Rate Methodology and the TVA Rate Methodology rely on the same inputs and generate almost identical average annual pole costs. They differ significantly, however, in their allocation of those costs.[1]

15. The primary difference between the FCC Rate Methodology and the TVA Rate Methodology is the allocation of the cost of the space on the pole.

16. Based upon the evidence presented in this docket, it is appropriate for the Commission to apply economic, cost-based principles in allocating costs of providing pole attachment service.[2]

17. Blue Ridge does not have any duty to construct facilities necessary to provide pole attachment services to Charter, and Charter is separately responsible for covering the EMC's measurable and verifiable costs that are directly attributable to Charter's attachments. Charter occupies space on Blue Ridge's poles only so long as that space is not required by Blue Ridge for its own utility service.[3]

18. While economic cost causation and cost allocation principles justify reliance on the FCC Rate Methodology, it is appropriate for the Commission to consider the public interest benefits and detriments from raising or lowering pole attachment rates under N.C. Gen. Stat. § 62-350.[4]

19. While economic cost causation and cost allocation principles justify reliance on the FCC Rate Methodology, it is appropriate for the Commission to consider the benefits from lower pole attachment rates on economic efficiency in the communications sector as well as, more specifically, the geographic expansion of broadband service.[5]

20. It is not appropriate for the Commission to treat non-profit and for-profit entities differently regarding pole attachment rates.[6]

21. Based upon the evidence herein presented, the FCC Rate Methodology for allocating the total costs of a pole based on the percentage of space used by the attacher established by the FCC and approved by the North Carolina Business Court and affirmed by the North Carolina

[1] Issue Nos. 1 and 2 per the November 2, 2017 Joint Statement of Issues.

[2] Issue Nos. 1 and 2 per the November 2, 2017 Joint Statement of Issues.

[3] Issue Nos. 1 and 2 per the November 2, 2017 Joint Statement of Issues.

[4] Issue Nos. 1 and 2 per the November 2, 2017 Joint Statement of Issues.

[5] Issue Nos. 1 and 2 per the November 2, 2017 Joint Statement of Issues.

[6] Issue Nos. 1 and 2 per the November 2, 2017 Joint Statement of Issues.

Court of Appeals is the appropriate methodology for allocating the total costs of the pole, including unusable space.[1]

22. The costs associated with the "safety space" on a pole should be allocated in accordance with the FCC Rate Methodology.[2]

23. The parties disagree as to whether the Commission should use the FCC Rate Methodology's or the TVA Rate Methodology's presumptions in determining the appropriate rate for Charter's attachments to Blue Ridge's poles, or whether the Commission should employ actual data Blue Ridge has introduced to rebut those presumptions.

24. The FCC Cable Rate Methodology employs rebuttable presumptions regarding the height and use of a utility's poles, which include presumptions that: (i) the average height of a distribution pole is 37.5 feet; (ii) these poles are, on average, buried six feet deep, and (iii) in order to maintain proper clearances, the lowest attachment on a pole must be at least 18 feet off the ground. In applying the FCC Cable Rate, the FCC treats these presumptions as rebuttable. *See* 47 C.F.R. § 1.1418 (providing that the presumptions regarding space occupied by cable company's attachment, the amount of usable space, and average pole height "may be rebutted by either party").

25. The TVA Rate Methodology also employs rebuttable presumptions.

26. According to Blue Ridge's records and recently collected audit data, Blue Ridge had an average of 2.35 attachers on its poles (*i.e.*, Blue Ridge, Charter, and other third-party attachers) in the years 2014, 2015, and 2016.

27. According to Blue Ridge's Rural Utilities Service (RUS) and accounting records, Blue Ridge's actual data shows the following:

a) __Pole Height__. The average height of Blue Ridge's distribution poles, calculated using its continuing property records, is roughly one foot less than the 37.5 feet presumption under the FCC cable rate, resulting in average pole heights of (a) 36.83 feet for 2014, (b) 36.85 feet for 2015, and (c) 36.87 feet for 2016.

b) __Attachment Height__. The FCC cable formula presumes that all entities attaching to the pole require 18 feet of ground clearance, and thus the first attacher will attach at this height, rendering the remainder of the pole "usable space." However, because Blue Ridge's poles are spaced farther apart than is typical, attachers are required to make the first attachment higher on the pole in order to maintain ground clearance. As a result the first available attachment on Blue Ridge's poles based on its yearly average pole height was (a) 21.3 feet in 2014, (b) 21.8 feet in 2015, and (c) 21.26 feet in 2016. This necessarily results in less "Usable Space" and more "Support Space" that must be allocated among the attachers.

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[1] Issue Nos. 1 and 2 per the November 2, 2017 Joint Statement of Issues.

[2] Issue Nos. 1 and 2 per the November 2, 2017 Joint Statement of Issues.

c) **Appurtenance Factor**. While the FCC Cable rate presumes an appurtenance rate of 15%, meaning 85% of a utility's Account 364 is attributable to distribution poles, Blue Ridge's true bare pole costs, net of appurtenances, were (a) 87.0% for 2014; (b) 87.29% for 2015; and (c) 87.41% for 2016.

d) **Number of Attachments / Occupied Space**. The FCC Cable Rate presumes that cable company attachments use only one foot of space, and that a cable company only attaches once to each pole. Blue Ridge's 2015-2016 pole audit showed that Charter had 27,674 attachments on 24,888 poles. This means Charter has an average of 1.11 attachments per pole, which is reflected by showing that it uses 1.11 feet of space as opposed to the FCC Rate Methodology presumption of 1 foot of space.

28. The evidence that Blue Ridge provided to rebut the FCC Rate Methodology's presumptions is reliable, and more accurately reflects the costs and the parties' use of Blue Ridge's distribution poles. It is therefore appropriate to use the actual data provided by Blue Ridge with the FCC Rate Methodology to calculate the maximum pole attachment rates that Blue Ridge may charge Charter.

29. Blue Ridge's maximum just and reasonable pole attachment rates for the years 2015-2017 should be determined based on the FCC's Rate Methodology.

30. The FCC Rate Methodology presumptions should be replaced with actual data provided by Blue Ridge. When Blue Ridge's actual data is employed in the FCC Rate Methodology, the resulting rates for rate years 2015, 2016, and 2017, are as follows:

2015 - $8.49 per pole
2016 - $8.37 per pole
2017 - $8.31 per pole

31. Charter paid the following rates to Blue Ridge for 2015 through August 2017:[1]

2015 - $26.64 per year
2016 - $26.64 per year
2017 - $26.64 per year

32. Blue Ridge owes a refund to Charter for excessive pole attachment fees paid from August 25, 2015, through August 31, 2017, and for excessive pole attachment fees paid after August 31, 2017.[2]

[1] Issue Nos. 1 and 2 per the November 2, 2017 Joint Statement of Issues.

[2] Issue Nos. 1 and 2 per the November 2, 2017 Joint Statement of Issues.

33. In addition to a just and reasonable pole attachment rate, it is appropriate for Charter to pay Blue Ridge's measurable and verifiable costs directly attributable to Blue Ridge providing pole attachment space to Charter.[1]

34. It is appropriate for the Commission to look to industry standard provisions in agreements negotiated in regulated and unregulated situations as cogent evidence of reasonableness.[2]

35. Issues regarding the condition and compliance of Charter's outside plant as presented at the hearing are not yet ripe for Commission consideration.[3]

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-4

The evidence supporting these Findings of Fact is found in the Joint Stipulations and the record of evidence.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-13

The evidence supporting these Findings of Fact is found in the testimony of Charter witnesses Kravtin, Martin and Mullins, Blue Ridge witness Arnett, the Joint Stipulations, and the record of evidence.

Witness Kravtin testified that the FCC has regulated pole attachment matters, including how to set just and reasonable, cost-based pole attachment rates, for many years. [Kravtin Tr. Vol. 4, pp. 168-69.] As noted by witness Kravtin, the rate methodology approved by the FCC under 47 U.S.C. § 224(d) has been found by numerous courts, including the United States Supreme Court, to be compensatory and subsidy free. [Tr. Vol. 4, pp. 201-02 & n.43.][4] The FCC has issued scores of decisions implementing its rate formula and has reaffirmed the formula recently in Restoring Internet Freedom, WC No. 17-108, Declaratory Ruling, Report & Order, 2018 WL 305638, ¶¶ 185-91 (FCC 2018). Witness Kravtin testified that reliance on this well-understood and easy-to-apply methodology would avoid the need for constant Commission refinement and explanation. [Kravtin, Tr. Vol. 4, p. 204.]

As explained by witness Kravtin, the FCC Rate Methodology[5] is applied directly to electric IOUs and incumbent local exchange carriers (ILECs) in those 30 states that have not chosen

[1] Issue Nos. 1 and 2 per the November 2, 2017 Joint Statement of Issues.

[2] Issue No. 3 per the November 2, 2017 Joint Statement of Issues.

[3] Issue No. 3 per the November 2, 2017 Joint Statement of Issues.

[4] *See, e.g.*, FCC v. Florida Power Corp., 480 U.S. 245, 253-54 (1987).

[5] Pursuant to 47 U.S.C. § 224(d)(1), the FCC has regulated pole attachments made by cable operators to provide cable service since 1978. Adoption of Rules for the Regulation of Cable Television Pole Attachments, CC No. 78-144, First Report & Order, 68 FCC2d 1585, 1585, 1598-99 (1978). The Commission will refer to this rate methodology throughout as the "FCC Rate." In 1996 Congress amended the Pole Attachment Act to provide for regulation of attachments made by telecommunications carriers to provide telecommunications service pursuant to 224 U.S.C. § 224(e). In 2011 and 2015, the FCC released orders bringing the "telecommunications" rate into line with the "cable rate." Implementation of Section 224 of the Act: A National Broadband Plan for Our Future, 26 FCC Rcd.

themselves to regulate pole attachment rates. *See* States That Have Certified That They Regulate Pole Attachments, Public Notice, WC No. 10-101, 25 FCC Rcd 5541, 5541-42 (2010). The pole attachment rates of IOUs and ILECs in North Carolina are based on the FCC Rate Methodology. [Kravtin, Tr. Vol. 4, p. 180; Martin, Tr. Vol. 4, p. 80.] The poles owned by IOUs and ILECs are "largely if not entirely indistinguishable" from the poles owned by the Cooperatives. [Kravtin, Tr. Vol. 4, p. 180.] Witnesses Martin and Mullins testified similarly. [Martin, Tr. Vol. 4, p. 77; Mullins, Tr. Vol. 3, p. 236.] Witness Kravtin testified that, due in part to historic joint use[1] pole agreements between ILECs and Blue Ridge, those parties have constructed poles with the same physical characteristics, often interspersed in a pole line. Further, these poles are sometimes adjacent to virtually identical poles owned by a federally regulated IOU. [Kravtin, Tr. Vol. 4, p. 180; Martin, Tr. Vol. 4, p. 77; Mullins, Tr. Vol. 3 p. 236.] Due to joint use agreements, in almost all situations, there is only one set of poles on any particular road.[2] [*See* Martin, Tr. Vol. 4, pp. 138-39.]

Witness Kravtin noted that the average pole attachment rate that Charter paid in 2016 to North Carolina IOUs and ILECs, which are regulated by the FCC under its standard rate methodology, was $7.20 for IOUs and $3.24 for ILECs. [Kravtin, Tr. Vol. 4, p. 234.] These rates are in the same range as the rates that witness Kravtin calculated for Blue Ridge under the FCC Rate Methodology. Witness Kravtin testified that it makes no sense from an economic perspective to have the rates charged by different types of entities vary widely. [Kravtin, Tr. Vol. 4, pp. 179-80, 246-47.] On the other hand, she testified that there are significant public interest benefits in having similar poles regulated similarly, regardless what type of entity owns them. [Kravtin, Tr. Vol. 4, pp. 196-97.]

Witness Kravtin also observed that the large majority of states that regulate pole attachments,[3] including poles owned by electric cooperatives, do so according to the FCC Rate Methodology or a close cousin. For example, she testified that Ohio, New York, California, Michigan, and Kentucky, along with 10 other states, all regulate IOU and ILEC pole attachment rates according to the FCC Rate Methodology or something very close to it. [Kravtin, Tr. Vol. 4, p. 204 and Ex. PDK 7.] While some of these methodologies were initially adopted decades ago, many have been reaffirmed more recently.[4] In addition, eleven states regulate the pole attachment

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5240, 5322 (2011), aff'd sub nom. Am. Elec. Power Serv. Corp. v. FCC, 708 F.3d 183 (D.C. Cir. 2013); Implementation of Section 224 of the Act: A National Broadband Plan for Our Future, Order on Reconsideration, 30 FCC Rcd. 13731 (2015).

[1] The term "joint use" refers to arrangements between different pole owners, generally electric and telephone providers, to each share their poles with the other entity.

[2] ***BEGIN CONFIDENTIAL***END CONFIDENTIAL***

[3] The Federal Pole Attachment Act allows states to "reverse-preempt" the FCC's pole attachment regulations so long as they meet certain federal standards. 47 U.S.C. § 224(c). To date, twenty states and the District of Columbia have reverse-preempted FCC jurisdiction over the rates, terms, and conditions of pole attachments in their states. *See* States That Have Certified That They Regulate Pole Attachments, WC No. 10-101, Public Notice, 25 FCC Rcd 5541, 5542 (FCC WCB 2010). North Carolina has chosen to allow the pole attachment service of IOUs and ILECs to continue to be regulated by the FCC.

[4] Implementation of Section 224 of the Act: A National Broadband Plan for Our Future, 26 FCC Rcd 5240, 5322 (2011), aff'd sub nom. Am. Elec. Power Serv. Corp. v. FCC, 708 F.3d 183 (D.C. Cir. 2013); Implementation of Section 224 of the Act: A National Broadband Plan for Our Future, Order on Reconsideration, 30 FCC Rcd. 13731

rates of cooperatives and/or municipal utilities according to the FCC Rate Methodology. [Ex. PDK 7.]

Witness Kravtin also testified that the National Association of Regulatory Utility Commissioners (NARUC) has strongly recommended that state utility commissions apply the FCC pole attachment rate methodology to electric cooperatives. [Kravtin, Tr. Vol. 4, pp. 204-05; Exs. PDK 11 and 12.] She also noted that the National Association of State Utility Consumer Advocates (NASUCA) has similarly endorsed the FCC formula for uniform application to all pole owners. [Kravtin, Tr. Vol. 4, pp. 204-05; Ex. PDK 13.] Witness Kravtin also pointed out that even the National Rural Electric Cooperative Association (NRECA), Blue Ridge's own national trade association, has found the FCC pole attachment formula to be "unimpeachable." [Kravtin, Tr. Vol. 4, pp. 242-43.]

Witness Kravtin, testified that the North Carolina Business Court relied on the FCC Rate Methodology to determine that the pole attachment rates sought by the Town of Landis and Rutherford EMC were excessive and neither just nor reasonable. [Kravtin, Tr. Vol. 4, p. 165; Time Warner Entertainment-Advance/Newhouse Partnership v. Town of Landis, No. 10-CVS-1172, 2014 WL 2921723 (N.C. Sup. Ct. Jun. 24, 2014) (Landis); Rutherford Electric Membership Corp. v. Time Warner Entertainment-Advance/Newhouse, No. 13-CVS-231, 2014 WL 2159382 (N.C. Super. Ct. May 22, 2014), aff'd, 771 S.E.2d 768 (N.C. Ct. App. 2015) (Rutherford).] The Rutherford case, which was unanimously affirmed in the Court of Appeals, found that, based on the evidence presented in that case, including the testimony of witness Kravtin,[1] "the FCC Cable Rate formula's allocation method, used to determine what percentage of the fully allocated costs to assign to the attaching party, provides an economically justified means of reasonably allocating costs." Rutherford, 2014 WL 2159382 at *9. "[F]ar from providing any subsidy to communications providers, the FCC Cable Rate formula actually leaves the utility and its customers better off than they would be if no attachments were made to their poles." Id.

Witness Arnett, testifying on behalf of Blue Ridge, urged the Commission to rely on a rate formula adopted by the TVA in a resolution dated February 20, 2016, which was developed for use by the local power distribution companies that are the TVA's wholesale electric power customers. [Arnett, Tr. Vol. 2, p. 46.] The TVA provides electric power to approximately 165 retail electric distributors in seven states, including three electric cooperatives in North Carolina: Blue Ridge Mountain Electric Membership Corp., Tri-State Membership Corp. and Mountain Electric Cooperative. [Arnett, Tr. Vol. 2, pp. 46-47.] Witness Arnett opined that the TVA considered the FCC Rate Methodology but rejected it as providing a "subsidy" to the attachers. [Arnett, Tr. Vol. 2, p. 84.] In developing the methodology, the TVA noted that,

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(2015); *see also,* Consideration of Rules Governing Joint Use of Utility Facilities and Amending Joint-Use Regulations Adopted Under 3 ACC 52.900 – 3 AAC 52.940, Order Adopting Regulations, 2002 Alas. PUC LEXIS 689, at *3-6 (Alaska Pub. Util. Comm'n 2002); Order Instituting Rulemaking on the Commission's Own Motion into Competition for Local Exchange Service, Decision 98-10-058, 1998 Cal. PUC LEXIS 879, at *87-88 (Cal. Pub. Util. Comm'n 1998); Application of Consumers Power Co., Nos. U-10741, U-10816, U-108211, Opinion and Order, 1997 Mich. PUC LEXIS 26, at *32-33 (Mich. Pub. Util. Comm'n 1997); Rulemaking to Amend Oregon Admin. Rules Relating to Safety and Attachment Standards, Order No. 01-839, 2001 Ore. PUC LEXIS 483, at *13-15 (Ore. Pub. Util. Comm'n 2001).

[1] Witness Kravtin served as an expert for Time Warner Cable Southeast LLC in the Rutherford and Landis cases.

"[u]nlike the FCC, however, the TVA is charged with keeping electric rates as low as feasible, and ensuring that electric ratepayers do not subsidize other business activities is important in achieving this objective." [WA Ex. 3; PDK Ex. 14 at Attachment B.] Although witness Arnett testified that the TVA Rate Methodology is based, at least in part, on the TVA's "recogni[tion] that certain portions of the poles are of equal benefit to all attaching parties" [Arnett, Tr. Vol. 2, p. 53], a review of the TVA's resolution and supporting documentation does not reflect any such finding. [*See* WA Ex. 3.]

In support of his testimony urging the Commission to adopt the TVA Rate Methodology, witness Arnett relied on rate methodologies (i) considered by the United States House of Representatives (but never adopted by Congress), (ii) adopted by the Arkansas Public Service Commission, and (iii) recommended by the APPA. [Arnett, Tr. Vol. 2, pp. 67-77.] While none of these other methodologies exactly mirrors that adopted by the TVA, witness Arnett testified that each of them shared some common elements with the TVA's methodology.

Witness Arnett also relied on 1954 guidance from the Rural Electric Administration (REA) about how rates for joint use arrangements between telephone companies and EMCs, which both owned poles shared by the others, should be set. [Arnett, Tr. Vol. 2, pp. 102-03 and WA Ex. 31.] He did not address, however, whether the rights of telephone joint users and those of cable operators like Charter are equivalent, agreeing at the hearing that the REA method was meant for users who each own a percentage of the pole.[1] [Arnett, Tr. Vol. 2, p. 157.] Although witness Arnett attacked the FCC rate formula as unreasonable in his judgment, he did not address the independent and affirmative decisions reached by 15 states to follow the FCC method, or the recommendations of other objective bodies such as NARUC and NASUCA, that state utility commissions should follow the FCC Rate Methodology, or the finding by the NRECA that the FCC rate method is "unimpeachable." [*See* Arnett, Tr. Vol. 2, pp. 84 and 161-63.]

In response to witness Arnett's recommendation of the TVA Rate Methodology, witness Kravtin pointed out that the TVA does not have general jurisdiction over pole attachment matters and that the TVA explicitly declared its sole objective to be to keep pole rates high in order to support lower electric rates. Also, witness Kravtin stated that the TVA rate was the product of a closed process that involved only parties that stood to benefit from higher pole attachment rates. As noted by witness Kravtin, the TVA did not conduct a public proceeding or seek the input of any parties other than the pole owners and their trade association. [Kravtin, Tr. Vol. 4, pp. 173-74.] Witness Kravtin testified that the "TVA's rejection of the FCC Rate, for example, was based on a number of patently false premises likely supplied by its customers and their advocates, and without the benefit of any information from other stakeholders, a complete record, or an open debate to better inform its findings." [Kravtin, Tr. Vol. 4, p. 218.] Witness Kravtin dismissed the APPA's recommendation as "another industry-driven formula designed to serve the self-interest of its public power company members." [Kravtin, Tr. Vol. 4, p. 220.] Witness Arnett confirmed that he has no knowledge of any other regulator ever following the methodologies used in his referenced proceedings or the approach advocated by the APPA. [Arnett, Tr. Vol. 2, p. 146.] Witness Kravtin also observed that the TVA has itself announced plans to invest in its own fiber

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infrastructure, which will be used to compete with cable operators. [Kravtin, Tr. Vol. 4, pp. 219-20 and n.64.]

Discussion and Conclusions

The Commission has exclusive jurisdiction under N.C. Gen. Stat. § 62-350 to determine the just and reasonable rates that Blue Ridge can charge Charter for attaching its facilities to Blue Ridge's poles. In making that determination, the Commission, in its discretion, may consider any evidence or rate-making methodologies offered or proposed by the parties to arrive at its decision as to the just and reasonable rates that Blue Ridge is authorized to charge Charter.

During the hearing, both Blue Ridge and Charter discussed numerous state and federal decisions, and rate methodologies and methods which had been developed and/or applied by various state commissions, energy and communications related interest groups, organizations and federally established regulatory and administrative agencies. However, at hearing, Charter and Blue Ridge each advocated that the Commission adopt its preferred rate-making methodology and find that the alternative proposed by the other party was inappropriate. More specifically, Charter requested that the Commission adopt the FCC Rate Methodology to determine the just and reasonable rate that Blue Ridge should charge Charter to attach to Blue Ridge's poles and determine that the TVA Rate Methodology advocated by Blue Ridge was inappropriate for that purpose. And, Blue Ridge requested that the Commission adopt the TVA Rate Methodology to determine the maximum just and reasonable rate that Blue Ridge may charge Charter to attach to Blue Ridge's poles and determine that the FCC Rate Methodology advocated by Charter was inappropriate for that purpose. That is, the parties have requested that the Commission determine whether the FCC Rate Methodology or the TVA Rate Methodology is the proper methodology for the Commission to use to determine the just and reasonable rates that Blue Ridge should charge for Charter to attach to its poles.

The FCC Rate Methodology is widely recognized as a reasonable regulatory tool for this Commission to follow. It is used by the FCC to set maximum pole attachment rates of IOUs and ILECs in thirty states, and applies in North Carolina to poles that are often identical to and interspersed with poles owned by Blue Ridge in its service territory. It, or a closely related methodology, is used by state agencies to set pole attachment rates in 15 other states in their own, independent regulation of pole attachments. It is strongly recommended by NARUC and NASUCA as the appropriate rate methodology for regulating EMC pole rates, and even Blue Ridge's own national trade association has termed it "unimpeachable." The FCC Rate Methodology has been upheld in the federal courts, including the United States Supreme Court, as compensatory. And, importantly, it was found by the North Carolina Business Court, in a decision unanimously affirmed in the Court of Appeals, to present a reasonable rate methodology that benefits the pole owner.

The TVA Rate Methodology, on the other hand, was adopted for a specific and limited purpose, to keep electric rates low, and was the result of a process that involved only those that would benefit from high pole attachment rates. The evidence before the Commission is that neither the parties that will have to pay the TVA pole attachment rates nor members of the public who may be affected were consulted. The Commission, therefore, will give minimal weight to the fact that the TVA rejected the FCC Rate Methodology and adopted a different one. The extent to which the TVA approach has any merit must stand or fall entirely on its economic underpinnings and public interest considerations.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 14-15

Evidence supporting these Findings of Fact is found in the testimony of witnesses Kravtin, Arnett, Layton and Mullins.

The pole attachment rate methodology applied by the TVA in its February 2016 resolution relies on the historic FCC Rate Methodology for most of the cost inputs. As described by witnesses Kravtin and Arnett, both methods use the same utility accounts to determine the average net cost of a utility pole and multiply by the same elements to derive an average annual cost to own and maintain a pole. The numbered accounts of the RUS (used by Blue Ridge and other EMCs) and the Federal Energy Regulatory Commission (FERC) accounts (used by IOUs to compute the FCC Rate) are the same. Both the FCC and the TVA presume that 15% of the pole investment account (Account 364 in both RUS and FERC accounting) consists of appurtenances such as cross arms and other facilities and hardware that are not used by attaching third parties. The FCC and the TVA both presume that 15% of the costs in that account should be subtracted out in determining the net cost of an average pole. Both the FCC and the TVA also create an annual carrying charge for the average pole by factoring in the annual cost of depreciation, maintenance, taxes (if any), administrative and general expenses and a rate of return.

The formulas used by both the FCC and the TVA to derive an annual cost of a pole are virtually identical, as depicted below in Figures 1 and 2.[1]

FIGURE 1

FCC Cable Rate Formula =
Net Bare Pole Cost (NBP) x Carrying Charge Factor (CCF) x Space Allocation Factor (SAF)
Where the SAF = Space Occupied by Attacher / Usable Space on Pole

[Kravtin, Tr. Vol. 4, p. 186.]

FIGURE 2

TVA Rate Formula =
Pole Attachment Rate = (Space Allocation) x (Net Cost of Bare Pole) x (Carrying Cost)

[*See* WA Ex. 2.1-2.3]

[1] The only differences are that the TVA relies on a three-year average for maintenance expenses while the FCC relies on a single year, and the TVA uses a rate of return of 8.5% while the FCC relies on a default rate of return of 11%. [Arnett, Tr. Vol. 2, p. 49; Kravtin, Tr. Vol. 4, pp. 188-89, 229.]

Witnesses Kravtin and Arnett agreed that the difference between the FCC Rate Methodology and the TVA Rate Methodology lies in their allocation of the annual cost of the pole to the third-party communications service provider. They explained that the TVA has followed the FCC method in dividing the pole, and the annual cost thereof, into "usable" and "unusable" space. Both the FCC and the TVA presume an average pole as being 37.5 feet long. Both presume that the bottom 6 feet of the pole are buried to give the pole stability, and both presume that attachments cannot be made lower than 18 feet above ground in order to achieve the necessary minimum ground clearance to avoid contact between the wires attached to the poles and vehicles traversing underneath. The TVA, like the FCC, treats this 24 feet of space as "unusable." Both the FCC and the TVA consider the 13.5 feet of space that is above the 18 foot minimum ground clearance on an average pole to be "usable" for the attachment of wires, cables and other revenue-generating facilities. Both the FCC and the TVA also presume that a communications attachment occupies one foot of this usable space. [Kravtin, Tr. Vol. 4, pp. 186-87 and n.29; Arnett, Tr. Vol. 2, pp. 49-51.]

As explained by witnesses Kravtin and Arnett, both the FCC and the TVA also recognize that the electric attachments occupy the upper-most portion of the usable space, and the communications attachments occupy the lower portion of the usable space. Both also recognize that the National Electric Safety Code (NESC) requires a 40-inch "safety space" (termed by the NESC as the "Communication Worker Safety Zone") (the "safety space") between some energized conductors and communications facilities.

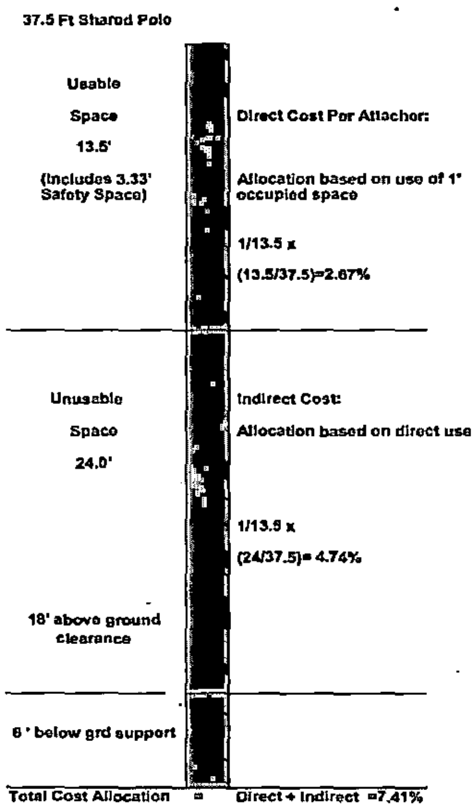
Witnesses Kravtin and Arnett agreed that the NESC has exceptions to the 40-inch safety space and allows street lights, traffic control devices, and even communications facilities owned by the pole owner to be placed within the "safety space." Both witnesses, and others on behalf of Blue Ridge and Charter, agreed that the placement of devices such as street lights in the safety space generates revenue for Blue Ridge. [Kravtin, Tr. Vol. 4, p. 209 n.49; Arnett, Tr. Vol. 2, pp. 56-57, 165-166; Mullins, Tr. Vol. 3, pp. 245-246; Layton, Tr. Vol. 1, p. 20.]

The testimony of witnesses Kravtin, Mullins and Arnett differed in their description of the purpose and effect of the safety space. Witness Kravtin testified that the safety space is required only because of the danger caused by electric shock and that from an economics point of view the need for the safety space relates to the electrification of Blue Ridge's facilities. [Kravtin, Tr. Vol. 5, p. 35.] Her economic benefit assessment was supported by the testimony of witness Mullins who explained that the safety space benefits the employees of both the electric utility and communications attachers by lessening the likelihood that any of these workers will come into simultaneous contact with the electrical and communications facilities. [Mullins, Tr. Vol. 3, pp. 245-46.] Witness Arnett, on the other hand, testified that the safety space is required only because the communications facilities are present on the pole. [Arnett, Tr. Vol. 2, p. 56.] Although witness Arnett testified that Blue Ridge does not often attach facilities in the safety space, he agreed with witness Kravtin that Blue Ridge is allowed to place its facilities in that space and does so. [Arnett, Tr. Vol. 2, pp. 57-58, 164-65.]

Witness Kravtin explained that the FCC uses a "proportionate" and "cost-based" method to allocate the costs of attachment, based on the percentage of the usable space on a pole that is occupied by the attachment. In other words, the communications attacher is allocated the percentage of the annual cost of the entire pole represented by the percentage of the space "usable" for the attachment of revenue generating facilities that is occupied by the attacher's attachment. Presuming that the communications attachment occupies one foot and that there are 13.5 feet of space that are "usable" for attachments, the FCC allocates 1/13.5 (or 7.41%) of the costs of the entire pole to the communications attacher. The FCC treats the safety space as usable to the pole owner, and does not assign any of that space directly to the communications attacher, meaning that the communications attacher pays 7.41% of the costs of that space, as it does of the entire pole.

The FCC method of allocation is reflected in Figure 3.

FIGURE 3

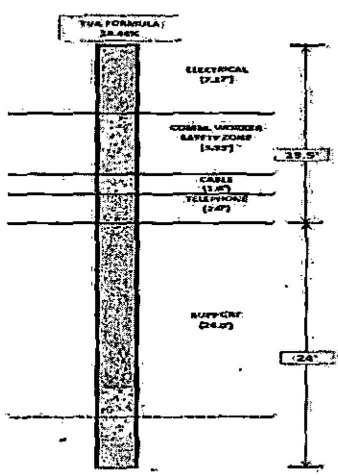


[Ex. PDK 9.]

According to witnesses Kravtin and Arnett, the TVA's allocation method also relies upon the proportionate allocation method used by the FCC for allocation of the costs of the pole space that is above the safety space. [Kravtin, Tr. Vol. 4, pp. 185-87, 219; Arnett, Tr. Vol. 2, pp. 49-51.] However, unlike the FCC, the TVA assigns to the third party communications service provider more than the one foot of space its attachment actually occupies. The TVA also assigns to all communications service providers that use the pole (and none to the EMC pole owner) the entire cost of the 40-inch safety space.[1] In addition, the TVA allocates the cost of the 24 feet of unusable space to all attachers, including the EMC pole owner, on a per-capita basis. In other words, the cost of the unusable space is allocated on an equal basis to all pole users. The TVA presumes that there are three entities that use an average pole, but allows the pole owner to rebut that presumption. The TVA allocation method, as proposed in witness Arnett's exhibit, is reflected in Figure 4.

The TVA relies on the same factual presumptions relied on by the FCC. These include presuming that (i) an average pole has three attaching parties, (ii) an average pole is 37.5 feet tall and has 13.5 feet of usable space and 24 feet of unusable space, and (iii) a communications provider's attachment occupies one foot of usable space. [Kravtin, Tr. Vol. 4, pp. 186-87; Arnett, Tr. Vol. 2, pp. 49-52.] Applying these FCC/TVA presumptions, the TVA Rate Methodology allocates 28.44% of the total pole costs to each third party communications service provider.

FIGURE 4



[Arnett, Tr. Vol. 2, p. 54.]

[1] In other words, if Charter were the only communications service provider on the pole, the TVA would allocate all of the cost of the 40-inch safety space to Charter. If Charter and another communications service provider occupied the pole, the cost of the 40-inch safety space would be allocated evenly between the two providers.

Discussion and Conclusions

The evidence establishes that the TVA has modeled much of its rate methodology on that used for many years by the FCC. The basic reliance of the formula on the cost accounts of the particular utility, the inputs relied on, and the structure of the formula used by the TVA mirrors closely the FCC's formula. The TVA also relies on the same presumptions about pole space relied on in the FCC formula: that an average pole has 24 feet of unusable space and 13.5 feet of usable space, and that a communications attachment occupies one foot of the usable space.

Only in the allocation of these costs to the attaching parties does the TVA chart a new path. Whereas the FCC bases its allocation methodology on the theory that the costs of the entire pole should be assigned based on the attacher's occupancy of a portion of the usable, revenue-generating space, the TVA assigns only the costs of the usable space under that theory. Unlike the FCC, the TVA assigns the cost of the 24 feet of unusable space equally among all providers on the pole (including the pole owner) on a per-capita basis. Further, the TVA assigns the costs of the 40-inch safety space entirely to the communications service providers and none to the EMC pole owner. The FCC, on the other hand, treats the safety space as usable to the pole owner and does not allocate any of that space directly to the communications services provider(s). The FCC thus allocates the cost of the safety space according to the same percentage as it allocates the costs of the usable space.

The result of these allocation methods is that, where the presumptions jointly applied by both the FCC and the TVA are employed, the FCC assigns 7.41% of the annual costs of the entire pole to the communications services provider. The TVA assigns 28.44% of the pole costs to each of the communications services providers under those same presumptions, such that two communications services providers would pay more of the pole's costs (56.88%) than the pole owner (43.12%).

The FCC Rate Methodology employs rebuttable presumptions regarding the height and use of a utility's poles, which include presumptions that: (i) the average height of a distribution pole is 37.5 feet; (ii) these poles are, on average, buried six feet deep, and (iii) in order to maintain proper clearances, the lowest attachment on a pole must be at least 18 feet off the ground. In applying the FCC Rate Methodology, the FCC treats these presumptions as rebuttable by either party.[1] The TVA Rate Methodology also employs certain rebuttable presumptions. Because witness Arnett determined that Charter has an actual average of 2.35 entities attached to its poles, and attempted to rebut the presumptions that average poles have 13.5 feet of usable space and 24 feet of unusable space, he allocated a total of 41.16% (for 2016) of Blue Ridge's pole costs to Charter alone.

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[1] See 47 C.F.R. § 1.1418 which provides that with respect to the FCC Cable Rate Methodology: "the space occupied by an attachment is presumed to be one (1) foot. The amount of usable space is presumed to be 13.5 feet. The amount of unusable space is presumed to be 37.5 feet. These presumptions may be rebutted by either party."

ELECTRIC COOPERATIVES – MISCELLANEOUS

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 16-17

The evidence supporting these Findings of Fact is found in the testimony of witnesses Kravtin, Martin, Mullins, Arnett, and Layton.

Witness Kravtin is a trained, practicing economist, who was educated in the field and has many years of experience in dealing with the economic basis for utility rates, in particular pole attachment rates. [Kravtin, Tr. Vol. 4, pp. 162-64.] She testified that the primary purpose of pole attachment regulation is to protect "cable operators and other communications attachers against potential abuse by pole-owning utilities that control access to a vital input of production needed by those attachers." [Kravtin, Tr. Vol. 4, p. 174.] Excessively high pole attachment rates, she observed, act like a tax that raises the cost to the communications companies of doing business. [Kravtin, Tr. Vol. 4, p. 175.] Ultimately, such rates result in higher prices for the communications services and distort that market. [Kravtin, Tr. Vol. 4, p. 175.]

Witness Kravtin also provided testimony concerning the economic underpinnings of the FCC pole attachment rate allocation method, pointing out that the FCC allocation is based on the fundamental economic principle of cost-causation in that costs lacking a direct or strong causal linkage to the provision of the service at issue (such as overhead and other common costs) are allocated in the same ratio as direct costs characterized by a strong cost causal linkage. [Kravtin, Tr. Vol. 4, pp. 190-91.] The rate formula allocates costs of the entire pole based upon the use of the space on the pole that is usable for revenue generating activities. Said another way, she testified that the FCC cost assignment method "allocates costs attributable to *both* usable and unusable space on the pole based on the attacher's direct occupancy of space." [Kravtin, Tr. Vol. 4, p. 170 (Emphasis original.).] She described the FCC Rate formula as based on a "widely accepted methodology, with a longstanding history of use in state and federal regulatory cost allocation manuals." [Kravtin, Tr. Vol. 4, p. 189.]

The FCC Rate, she observed, is similar to that "commonly used in leasing arrangements throughout the economy, in which the costs associated with common space of the facility are allocated to individual tenants on the basis of the tenant's direct occupancy of space on the shared facility." [Kravtin, Tr. Vol. 4, p. 192.] Relying on a real estate example, she pointed out that if a tenant leases one of the 10 floors of a building while the owner uses the other 9 floors, the tenant would not be expected to pay more than one-tenth of the costs of the common space, such as the lobby, elevator, garage and grounds. The tenant would not be charged one-half of the common space costs simply because two entities share use the common space. [Kravtin, Tr. Vol. 4, pp. 192-93.] Similarly, she testified that the same concept is used in allocating common costs for shopping malls and airport terminals. [Kravtin, Tr. Vol. 4, p. 193.] "[A]s an economic matter, the costs associated with space on the pole do *not* vary according to the number of attaching entities but rather to the economic utilization of pole capacity." [Kravtin, Tr. Vol. 4, pp. 194-95 (emphasis original).]

The FCC Rate, witness Kravtin emphasized, is fully compensatory and does not provide any kind of subsidy to the communications attachers. In reaching that conclusion, she explained that as an economic term a "subsidy" is present only when a rate does not cover marginal costs, defined as the additional costs that would not exist but for the product sold. [Kravtin, Tr. Vol. 4, pp. 197, 206-07.] "It is a central and well-established tenet of economics that rates that recover the marginal costs of production are economically efficient and subsidy-free." [Kravtin, Tr. Vol. 4, p. 197 n.35.] On the other hand, she stated, any recovery higher than marginal cost, which is clearly recovered under the FCC Rate Methodology, prevents any subsidy from Blue Ridge's electric customers to Charter and its communications customers. [Kravtin, Tr. Vol. 4, pp. 198-201.] She also noted that the FCC and numerous courts, including the U.S. Supreme Court, have held that the FCC pole attachment rate formula is fully compensatory to the pole owner and does not result in a subsidy.[1] [Kravtin, Tr. Vol. 4, p. 201-02, n.43.][2]

Witness Kravtin further supported her rate recommendation based on the following economic benefits: (1) the FCC Rate achieves "competitive and technical neutrality" since it can be applied uniformly across different utilities; (2) the FCC Rate "best mimics a competitive market outcome"; and (3) the FCC Rate provides "straightforward, consistent and predictable rates." [Kravtin, Tr. Vol. 4, pp. 195-203.] Witness Kravtin also noted that to allocate costs based on the number of attaching parties, as the TVA's methodology does, has no support in economic analysis and leads to arbitrary results. [Kravtin, Tr. Vol. 4, p. 191.] Further, she noted that it results in widely fluctuating rates based on the number of third party attachers. [Kravtin, Tr. Vol. 4, p. 226.] For example, witness Kravtin observed that a rate could double based on differences only in the number of attaching entities, even when the costs to the pole owner remain constant. [Kravtin, Tr. Vol. 4, p. 226.]

Witness Kravtin testified that the FCC Rate Methodology "adheres closely to the key economic and public policy principles of effective pole rate regulation." [Kravtin, Tr. Vol. 4, pp. 166-67.] In particular, she noted that the FCC Rate Methodology's use of its "proportionate" or "direct cost" allocator follows the principle of the "cost causer pays" [Kravtin, Tr. Vol. 4, p. 184], "commonly used in leasing arrangements in other sectors of the economy" such as commercial real estate. [Kravtin, Tr. Vol. 4, pp. 192-93, 208.] She also testified that excessively high pole

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[1] Amendment of Commission's Rules and Policies Governing Pole Attachments, Consolidated Partial Order on Reconsideration, 16 FCC Rcd. 12103, ¶¶ 15-25 (FCC 2001) ("2001 Reconsideration Order"); FCC v. Florida Power Corp., 480 U.S. 245, 253-54 (1987) (finding that it could not be "seriously argued, that a rate providing for the recovery of fully allocated cost, including the cost of capital, is confiscatory."); Alabama Power Co. v. FCC, 311 F.3d 1357, 1363, 1370-71 (11th Cir. 2002); Detroit Edison Co. v. Michigan Pub. Serv. Commission, Nos, 203421, 203480, slip op., 1998 WL 1988754, at *3-4 (Mich. Ct. App. Nov. 24, 1998), *affirming* Consumers Power Co., Detroit Edison Co., Setting Just and Reasonable Rates for Attachments to Utility Poles, Ducts and Conduits, Case Nos. U-010741, U-010816, U-010831, Opinion & Order (Mich. Pub. Serv. Comm'n Feb. 11, 1997), appeal denied, 461 Mich. 853, 602 N.W.2d 386, 1999 Mich. LEXIS 3252, 1999 WL 711854 (Mich.); Trenton Cable TV, Inc. v. Missouri Pub. Serv. Co., PA-81-0037, ¶ 4 (rel. Jan. 25, 1985) ("Since any rate within the range assures that the utility will receive at least the additional costs which would not be incurred but for the provision of cable attachments, that rate will not subsidize cable subscribers at the expense of the public.").

[2] It is noteworthy that the North Carolina Business Court also found that the FCC Rate does not result in a subsidy to a communications service provider such as TWC at the expense of the Cooperative. In discussing this very issue, the Court of Appeals found that the FCC Cable Rate "actually leaves the utility and its customers better off than they would be if no attachments were made to their poles" because the cable attacher "pays most of the incremental 'but for' costs of attachment up front, as well as its share of the fully allocated costs of pole ownership that necessarily would exist even absent its attachment." Rutherford Electric Membership Corp. v. Time Warner Entertainment-Advance/Newhouse Partnership, 240 N.C. App. 199, 213, 771 S.E. 2d 768, 778 (N.C. Ct. App. 2015). In terms of subsidies, the Court found that, if anything, in light of the agreement's terms, they flowed the opposite direction because "[w]hen [TWC] pay[s] to create surplus space where it does not already exist, [the Cooperative] benefits from receiving a taller, stronger pole that enhances [the Cooperative's] network, and [TWC] remain[s] obligated to pay annual rent to maintain an attachment to that pole." Id.

attachment rates artificially raise costs of providing communications services and reduce consumer demand for and ability to pay for new and enhanced services, especially in less densely populated areas such as those served by Blue Ridge. [Kravtin, Tr. Vol. 4, pp. 175-76, 231.] As for the overall impact on Blue Ridge's electric rates, she testified that Charter's pole attachment payments at the current $26.64 rate in 2016 only amounted to a very small portion of Blue Ridge's total electric revenues. [Kravtin, Tr. Vol. 4, p. 176-77.][1]

In support of the FCC fully allocated rate, witness Kravtin emphasized the limited and contingent nature of Charter's rights to attach to Blue Ridge's poles. Witnesses Kravtin, Mullins and Martin testified that the current and proposed Blue Ridge pole attachment agreements give Charter the right to attach to poles only where the existing configuration of the pole will accommodate the attachment consistent with the NESC requirements. If there is insufficient unused space on the pole to accommodate the attachment, Charter will be allowed to attach only if it pays for reconfiguring the existing attachments on the pole or for installing a new pole, if necessary. Even if Charter has thus paid for a new pole, the pole is owned by Blue Ridge, and Charter pays annual rental to use it. In all cases where Charter's facilities are attached to a pole, the attachment is contingent on Blue Ridge not requiring the space for the latter's own utility services. If Blue Ridge needs the space sometime in the future, Charter is required to remove its attachment or pay at that time for a new pole.

Charter does not contest these provisions and recognizes that its pole attachment agreements, both currently and in the future, will provide the right to attach only in "surplus" or "excess" space. [Kravtin, Tr. Vol. 4, pp. 198-99, n.38; Mullins, Tr. Vol. 3, p. 224; Martin, Tr. Vol. 4, p. 141.] In addition, Charter's pole attachment agreements with Blue Ridge, both in the past and as proposed by both parties, require Charter to pay all out of pocket expenses incurred by the utility associated directly with the attachment. [Martin, Tr. Vol. 4, p. 84; Mullins, Tr. Vol. 3, p. 237.] Thus, Blue Ridge is permitted to charge Charter for the costs of pole inspections and audits, and all expenses related to making the pole ready for attachment, including post-construction review expenses. [Kravtin, Tr. Vol. 4, p. 198 n.36; Mullins, Tr. Vol. 3, p. 232; Martin, Tr. Vol. 4, p. 84.] Charter's contingent attachment rights and responsibility for absorbing Blue Ridge's "but for" costs related to Charter's attachments gives witness Kravtin assurance that the FCC fully allocated pole attachment rate does not create any kind of subsidy. [Kravtin, Tr. Vol. 4, pp. 206-07.]

Witness Arnett, who testified as a rate expert for Blue Ridge, is a consultant with decades of experience in representing pole owners, many of them cooperatives, in pole attachment matters. [Arnett, Tr. Vol. 2, pp. 43-44, WA Ex. 1.] But he is not an economist, does not have a college degree, and does not claim any educational background or professional training in dealing with rate issues. [Arnett, Tr. Vol. 2, pp. 132-33; WA Ex. 1.] On cross examination, he acknowledged that he has no background in rate making, no experience in rate making theory, and no knowledge of any rate allocation methods used by this Commission. [Arnett, Tr. Vol. 2, pp. 136-38.][2] In his

[1] ***BEGIN CONFIDENTIAL*** ***END CONFIDENTIAL***

[2] Witness Arnett testified that he has never been accepted as a rate expert in any judicial case and although he presented recommendations for how pole attachment rates should be set before two regulatory commissions, his rate recommendations were not accepted. He testified that he now believes that the rate methodologies he then recommended are not reasonable. [Arnett, Tr. Vol. 2, pp. 133, 140-42.]

testimony, witness Arnett did not purport to provide any economic analysis in support of his recommendation that the Commission follow the rate methodology adopted by the TVA in February 2016. Nor did he give any "economics" based justification for his contention that the FCC Rate results in Blue Ridge providing a subsidy to Charter. Instead, his testimony focused on explaining how the TVA Rate Methodology he advocates works, providing his intuitive support for the methodology, and pointing to other rate formulas that, in his view, are similar to that adopted by the TVA.[1]

In justifying the TVA's equal allocation of the costs of the "unusable space" (also referred to as "common space") on a pole, witness Arnett relied on the benefit to Charter in being able to use Blue Ridge's poles. Witness Arnett testified that the principles underlying the TVA Rate Methodology arise from the "TVA's regulatory philosophy that (a) the parties benefitting from the various sections of the pole should be responsible for those costs, and (b) where multiple parties derive benefit, those respective costs should be shared equally." [Arnett, Tr. Vol. 2, p. 49.] Although he testified that the "TVA recognizes that certain portions of the pole are of equal benefit to all attaching parties" [Arnett, Tr. Vol. 2, p. 53], he was not able to identify any evidence that the TVA had based its rate method on such a philosophy or recognition. [Arnett, Tr. Vol. 2, pp. 170-73.]

Nevertheless, witness Arnett testified that sharing the costs of unusable common space equally among all attaching parties makes sense because all attaching entities benefit equally from the common or unusable space on the pole and therefore should pay an equal share of those costs. [Arnett, Tr. Vol. 2, p. 55.] Witness Arnett asserted that "[a]ll attaching entities need" the portions of the pole that are buried in the ground and used to achieve minimum ground clearance. [Arnett, Tr. Vol. 2, p. 55.] In addition, witness Arnett testified that Charter, like all other attaching parties including Blue Ridge, uses the "unusable" pole space to transition between underground and aerial facilities through the use of "risers" and relies on this space for power supplies and other equipment. [Arnett, Tr. Vol. 2, p. 55.] Witness Arnett did not address witness Kravtin's testimony demonstrating that Charter has only a contingent right to use space on Blue Ridge's poles. Witnesses Layton and Arnett testified that Blue Ridge does not make any capital investment for Charter; Blue Ridge does not take account of, or even consider, the possibility that Charter may want to attach to a pole in designing its pole plant. [Layton, Tr. Vol. 1, pp. 31-32; Arnett, Tr. Vol. 2, pp. 94-95.]

Witness Arnett attacked the FCC rate as "subsidized." [Arnett, Tr. Vol. 2, pp. 84, 115.] He also argued that the Commission should consider the "benefits received" by Charter, essentially that Charter avoids the greater cost it would incur if it installed equivalent facilities underground. [Arnett, Tr. Vol. 2, pp. 80-82, 85.] Witness Arnett further testified that in comparing Charter's proposed annual payment per pole to the avoided costs of pole ownership, Charter's proposal "results in a subsidy instead of an equitable sharing of costs." [Arnett, Tr. Vol. 2, p. 84.]

Discussion and Conclusions

The disagreement between the parties regarding the appropriate rate methodology to apply is essentially threefold: (1) how to allocate the costs associated with the unusable portion of the

[1] See discussion at pp. 16-17 supra.

pole among users of the pole, (2) how to allocate the cost associated with the "safety space" on the pole among users of the pole and (3) whether Blue Ridge's actual data should be used to calculate the maximum pole attachment rate in lieu of the presumptions used in the FCC and the TVA rate methodologies.

Allocating the annual costs of owning and maintaining a pole based on the percentage of the usable and revenue-generating space occupied by the attachment is supported by well-recognized cost-causation principles and is consistent with previous decisions of the Commission in analogous circumstances. *See* Order Addressing Collocation Issues, Docket No. P-100, Sub 133j (NCUC Dec. 28, 2001), at 17 (concluding in a proceeding involving competitive access to incumbent telephone company central office facilities that "it is appropriate to allocate security costs to carriers based on square footage occupied in the central office as a recurring charge," and rejecting the arguments of BellSouth and Verizon to allocate the costs on a pro-rata basis among the occupants of the property) (Collocation Order), motion for recon. denied, Order Addressing Motions for Reconsideration and Clarification, Docket No. P-100, Sub 133j (Aug. 20, 2002), at 118 ("[T]he Commission finds it appropriate to deny Verizon's Motion for Reconsideration and Clarification in this regard and affirms its original decision that security costs should be allocated based on square footage occupied in the central office."). This allocation method previously adopted by the Commission is the same as one would expect in a competitive real estate market where the costs of common space in a building are allocated on the basis of the number of apartments or floors occupied by each tenant, rather than simply based on a per-capita allocation. In fact, the Commission notes, when a tenant rents an apartment, the tenant typically has a lease that guarantees that the tenant has a right to stay in the rented space identified in the lease for a specific period of time. In this case, Charter can be forced to move to a different location on the pole or to leave a pole altogether at any time if Blue Ridge needs the space on the pole. Similarly, this method is how one would allocate the common costs of a factory production system (the costs of the building, conveyor belts, and so on) based on the direct costs of the different product lines, not simply dividing the common costs by the number of product lines. While it is true that all product lines benefit from the common costs, they do not benefit from them "equally" in any economic sense.

This approach is consistent with the general approach to cost allocation recognized and applied by the Commission as a foundation of its regulatory approach to setting rates, which seeks to allocate costs based on practical, observable or logical links to cost causation.[1] As also recognized by the FCC in establishing uniform methods of cost allocation in Part 64 of its Rules, where costs cannot be directly assigned to regulated or unregulated activities (i.e., "common costs"), they may be allocated "based upon an indirect, cost-causative linkage to another cost category . . . for which a direct assignment or allocation is available." 47 C.F.R. § 64.901(b)(3). In other words, where common costs can be linked to a method of direct assignment (i.e., the space occupied on a pole or facility), the direct method should be used to assign common costs.

[1] See, e.g., Commission Rule R9-2 (adopting FCC Uniform System of Accounts for telephone companies; requiring submission of cost allocation plans); Rule R8-27 (adopting FERC Uniform System of Accounts for electric utilities); and Rule R19-1 (requiring Electric Membership Corporations to file cost allocation manuals updated within 30 days of any significant change).

Based on the evidence presented in this docket, the Commission can discern no principled basis grounded in cost causation for the arbitrary allocation of costs associated with unusable space on a per-capita basis. Indeed, the theory seems rooted in the pure numerical convenience of dividing costs by users. Where the character and nature of the attachers' rights and patterns differ, as they do here, the use of this method of allocation is not sufficiently related to the costs that are being allocated. An attacher that occupies one foot of space on the pole does not stand in an equal position vis-à-vis the pole owner that (a) would own and operate the pole for its electric distribution needs regardless of the presence of an attacher, (b) has superior rights to utilize the entirety of the pole and may require the attacher to vacate the pole for the owner's use, and (c) uses a much greater portion of the pole as a whole. Similarly, an attacher that uses one foot of space does not stand in the same position as an attacher that uses two feet of space. The use of a space allocation factor consistent with the FCC approach also has the benefit of leading to more rational, less arbitrary pricing. The unrebutted evidence shows that adoption of Blue Ridge's proposed methodology would result in widely fluctuating rates depending on the number of third party attachers. Even where the costs of the pole remain constant, the rate charged for an attachment could double based solely on the number of attaching entities. Again, the Commission can perceive no principled reason why prices for attachment should vary so widely depending on the number of attaching parties.

Blue Ridge's argument that Charter benefits equally with Blue Ridge from the cost of the unusable space on a pole is not supported in the record and is the precise argument rejected by this Commission allocating space costs in the Collocation Order. *See* BellSouth Proposed Order, Docket No. P-100, Sub 133j, at 120 (Feb. 16, 2001) (arguing that security access "provides equal value to all parties; therefore, all parties should share equally in the costs of security services"). It is also the argument rejected by the Commission in the January 2018 Pole Attachment Orders. *See* e.g., Order Resolving Pole Attachment Complaint Pursuant to G.S. 62-350, Docket Nos. EC-43, Sub 88, EC-49 Sub 55, EC-55, Sub 70 and EC-39, Sub 44. (NCUC Jan. 9, 2018). The question is not whether Charter benefits from the portions of the pole that are buried and are used to achieve minimum grade clearance. Rather, the question is: what is the just and reasonable proportion of that cost to allocate to Charter. Blue Ridge did not choose to provide any expert economic testimony to support its position, and it is not clear from the record whether any such economic basis exists. Although there may be instances where allocating costs on a per-capita basis is appropriate in rate setting despite widely varying usage and rights, this case plainly does not present such a situation. The record here is clear not only that Charter occupies only a very small percentage of the usable space on the pole, but that even that occupancy is contingent and potentially temporary. Similar to the finding of the Business Court in the *Rutherford* case,[1] the record here does not establish that Blue Ridge expends capital to serve Charter by installing taller poles. To the contrary, Blue Ridge's witnesses made plain that it does not construct any pole plant to serve Charter. As stated by witness Kravtin, Charter occupies only "surplus" or "excess" space on the pole that is not required by Blue Ridge for its own purposes.[2] By any reasonable measure,

[1] Rutherford, 2014 WL 2159382 at *10.

[2] Witness Arnett disputed that Blue Ridge has any "surplus space," arguing that it does not create any space that it does not intend to use. [Arnett, Tr. Vol 2, pp. 94-95.] The Commission understands, however, witness Kravtin's position to be that the pole space occupied by Charter is "surplus" in the sense that it is not currently being used by Blue Ridge. When Blue Ridge needs the space, it is entitled to reclaim it.

Charter does not enjoy equal benefits to those of the pole owner from the common ("unusable") space on Blue Ridge's poles.

The argument that all parties' wires may traverse the "unusable" space between the ground line and the height necessary for minimum grade clearance with "risers" does not alter the Commission's analysis.[1] Risers are simply a means used by all parties to transition between underground and aerial facilities. The testimony was that risers do not affect the usefulness of any portion of the pole for attachment of wires and cables.[2] [Mullins, Tr. Vol. 3, p. 224.]

The Commission does not find a basis for deviating from this approach to cost allocation with respect to costs associated with maintenance of the so-called "safety space" on the pole. Blue Ridge's proposal would shift to communications service providers, including Charter, 100% of the costs associated with the safety space. The Commission finds unhelpful the "chicken or the egg" debate between witnesses Booth, Arnett and Kravtin about whether the safety space is required due to the presence of communications facilities on a pole or due to the fact that the pole carries energized and dangerous electric conductors. Obviously, it is the presence of both the communications facilities as well as the presence of electric power that creates the need for the space. Again, the question before the Commission is the appropriate method for allocating costs associated with that space. Based on the evidence presented here, the Commission is in agreement with the FCC and the Business Court that the safety space is actually usable (and used) by Blue Ridge for revenue generating facilities.[3] Blue Ridge's proposed methodology would have the inappropriate effect of allocating to Charter up to 100% of the costs of space it cannot use, while allocating to the pole owner none of the costs associated with space that it can and, in fact does, use.

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[1] Risers are vertical conduits used by all pole users to transition between underground and aerial service. The presence of a riser on a pole does not preclude other uses of that same space (there can be multiple risers on a single pole), and risers do not prevent the pole owner from making revenue-generating use of excess usable pole space for horizontal attachments.

[2] Nor does the fact that Charter occasionally places power supplies in the pole space below minimum grade affect the analysis. Power supplies are devices that enable the electric utility to generate electric revenue. The FCC has held that neither risers nor power supplies should count in its rate making method because both relate to the "unusable" and not the "usable" space. *See, e.g.*, Capital Cities Cable, Inc. v. Mountain States Tel. & Tel. Co., 1984 FCC LEXIS 2443, ¶ 23 (FCC June 29, 1984).

[3] Adoption of Rules for the Regulation of Cable Television Pole Attachments, Memorandum Opinion & Second Report & Order, 72 FCC 2d 59, 69-71 (1979) ("Second Report & Order") (finding, based on an extensive record, that safety space is to be considered usable space for ratemaking purposes, and that no portion of the safety space is to be considered occupied by cable television), aff'd on recon., 77 FCC 2d 187, 188-91 (1980) (affirming that "electric utilities make resourceful use of safety space for mounting street light support brackets, step-down distribution transformer and grounded shielded power conductors"); aff'd sub nom., Monongahela Power Co. v. FCC, 655 F.2d 1254, 1256 (D.C. Cir. 1981) (FCC's treatment of safety space as usable space was "a conscientious exercise of discretion," supported by the record evidence of "industry practice, ... on utility companies' profitable use of the safety clearance space, and ... the risk of replacement cost that many utility contracts [impose] on their [cable] lessees."); Amendment of Rules and Policies Governing Pole Attachments, Report & Order, 15 FCC Rcd 6453, 6467 ¶ 22 (2000) ("The [safety] space is usable and is used by the electric utilities."); Landis, 2014 WL 2921723 at *12; Rutherford, 2014 WL 2159382 at *15.

ELECTRIC COOPERATIVES – MISCELLANEOUS

The Commission takes notice of the following NESC provisions relating to the definition of the "communication worker safety zone."

Rule 238E defines "[c]ommunication worker safety zone" as:

> The clearances specified in Rules 235C and 238 create a communication worker safety zone between the facilities located in the supply space and facilities located in the communication space, both at the structure and in the span between structures. Except as allowed by Rules 238C, 238D, and 239, no supply or communication facility shall be located in the communication worker safety zone.[1]

Related to this definition:

- Rule 235C provides the vertical clearance at the support for line conductors and service drops.
- Rule 238 (Table 238-1) states, in pertinent part, that there must be a 40 inch vertical clearance between supply conductors and communications equipment, between communication conductors and supply equipment, and between supply and communications equipment for supply voltages from 0 kV to 8.7 kV.
- Rule 238C specifies the following clearances for span wires or brackets: "Span wires or brackets carrying luminaires, traffic signals, or trolley conductors shall have vertical clearances from communications lines and equipment not less than the values specified in Table 238-2."
- Rule 238D specifies the following clearance of drip loops associated with luminaires and traffic signals:

  > "If a drip loop of conductors entering a luminaire, a luminaire bracket, or a traffic signal bracket is above a communication cable, the lowest point of the loop shall be not less than 300 mm (12 in) above the highest (1) communication cable, or (2) through bolt or other equipment.
  >
  > *EXCEPTION*: The above clearance may be reduced to 75 mm (3 in) if the loop is covered by a suitable nonmetallic covering that extends at least 50 mm (2 in) beyond the loop."

- Rule 239 provides for the clearance of vertical and lateral facilities from other facilities and surfaces on the same supporting structure.

As noted above, the NESC only allows the safety space to be used by the electric company/pole owner to install such things as luminaires (street lights), traffic signals, or trolley conductors. Therefore, the Commission concludes that it is appropriate to classify the Communication Worker Safety Zone as usable space to the EMC as accounted for in the FCC Rate Methodology advocated for use in this proceeding by Charter.

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[1] 2017 NESC (C2 2017).

Blue Ridge's witnesses asserted in this case that very few of Blue Ridge's streetlights or other facilities are actually placed in the safety space, based on their interpretation of the NESC's definitions. [Booth, Tr. Vol. 3, pp. 116-17; Layton, Tr. Vol. 1, p. 82.] Witnesses Booth and Layton argued that even though Blue Ridge's streetlights may be found in the midst of the required 40 inch separation between Blue Ridge's neutral conductors and Charter's facilities, the streetlights are actually located in the Cooperative's "supply space," and not the "safety space." [Booth, Tr. Vol. 3, pp. 116-17; Layton, Tr. Vol. 1, p. 82.] In essence, witness Booth took the position that the safety space does not start at the lowest electrical conductor,[1] but starts at the bottom of the electric supply space, which he argues may be set by the EMC far below existing electrical facilities if the EMC desires to do so. [Tr. Vol. 3, pp. 180-82.]

Witness Booth's testimony in this matter that the Communication Worker Safety Zone is not tied to the location of existing facilities, and is based instead on some arbitrary and unilateral determination by the EMC pole owner of the lower bound of its "supply space" on a pole is hard to square with the wording of the NESC. But the Commission does not have to resolve the issue in this case. First, it is conceded by Blue Ridge's witnesses that the NESC allows the EMC to place its streetlights and other revenue generating facilities in the safety space, and that Charter is prohibited from placing its facilities in that space. [Layton, Tr. Vol. 1, pp. 121-22; Arnett, Tr. Vol. 2, pp. 56-58.] In other words, the safety space is "usable" by Blue Ridge but not "usable" by Charter, regardless of how the safety space is defined or where on a particular pole it is located. It would make no sense, therefore, to treat Charter as using the safety space and to treat Blue Ridge as not using it. Second, and most important, the evidence establishes that the presence of safety space on a pole never prevents Blue Ridge from placing any of its electrical facilities in that space on a pole. Due to Blue Ridge's rights at any time to commandeer any space on the pole for its facilities, the concept that safety space is in any way not "usable" by the EMC pole owner is not reasonable.

The Commission notes that the Business Court in the Rutherford case rejected the opinion of witness Booth, Blue Ridge's expert also in this case, that the cable operator should be held responsible for the safety space, finding that, "there is no basis for allocating the safety space entirely to the attacher as Booth did." Rutherford, 2014 WL 2159382, at *15. The Commission reaches that same conclusion based on the evidence presented here. Further, the Commission concludes that, based upon the evidence herein presented, the FCC Rate Methodology for allocating the total costs of a pole based on the percentage of space used by the attacher established by the FCC and approved by the North Carolina Business Court and affirmed by the North Carolina Court of Appeals is the appropriate methodology for allocating the total costs of the pole, including unusable space.[2]

[1] Witness Booth refused to agree that the definitions in the NESC Rules measuring vertical clearance requirements from surface to surface of the closest electrical supply lines and communications lines and specifying that the Communication Worker Safety Zone is established by the electrical facilities and the communications facilities mean that the safety space is tied to the location of existing facilities on the pole. [Tr. Vol. 3, pp. 165-81.]

[2] Issue Nos. 1 and 2 per the November 2, 2017 Joint Statement of Issues.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 18-20

The evidence supporting Findings of Fact Nos. 18-20 is found in the testimony of witnesses Kravtin, Martin, Mullins, Arnett and Layton.

The parties presented diametrically opposed theories of the purpose of pole attachment regulation. Witness Kravtin testified that pole attachments are regulated because they are a form of essential facility over which Blue Ridge (and other pole owners) have monopoly control, a fact that is supported by numerous decisions in the federal courts. [Kravtin, Tr. Vol. 4, p. 168.][1] She testified that "[t]he purpose of effective pole regulation is to protect cable and other communications attachers, for whom utility poles are essential bottleneck facilities, from being charged per unit attachment rates far in excess of a cost-based, competitive market level rate and from other harmful monopoly type practices of pole owning utilities." [Kravtin, Tr. Vol. 4, p. 167.] "Fundamental to pole rate regulation," in her opinion, "is recognition of the fact that pole-owning utilities, by virtue of historical incumbency, own and control existing pole plant to which cable operators and other communications attachers have no practical alternative to attach." [Kravtin, Tr. Vol. 4, pp. 174-75.] Witness Mullins testified that "due to economic, aesthetic, regulatory and other factors, Charter often has no practical alternative to using Blue Ridge's poles . . . ." [Mullins, Tr. Vol. 3, p. 227.] Further, there generally is a single set of poles on which to place aerial cables. [*See* Mullins, Tr. Vol. 3, p. 227; *see also* Martin, Tr. Vol. 4, p. 79.][2] Witness Mullins also testified that it would cost approximately $56 million (not counting the cost to wreck out existing aerial facilities) to move underground the facilities that Charter currently has attached to Blue Ridge's poles, which would be "prohibitively expensive." [Mullins, Tr. Vol. 3, pp. 223, 227-28.]

Witness Arnett, in contrast, testified that Blue Ridge's poles are not essential facilities to Charter because more than half of Charter's distribution infrastructure in North Carolina is placed underground and because some telephone companies have shifted their facilities from overhead to underground. [Arnett, Tr. Vol. 2, pp. 92-94] He testified that one of the telephone companies that currently attaches to Blue Ridge's poles removed approximately 1,400 of its total of 27,000 attachments from Blue Ridge's poles in the last five years. [Arnett, Tr. Vol. 3, p. 13.] He accepted, however, Charter's representation that it would cost about $45,109.40 per mile to move its aerial construction underground. [Arnett, Tr. Vol. 2, p. 85.] And none of Blue Ridge's witnesses addressed the feasibility of moving Charter's existing facilities off Blue Ridge's poles or how Charter could afford to continue to provide service if doing so required an additional investment of more than $45,000 per mile to serve what witness Mullins notes is a small number

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[1] *See, e.g.*, Nat'l Cable & Telecomm. Ass'n, Inc. v. Gulf Power Co., 534 U.S. 327, 330 (2002) ("[Cable companies have] found it convenient, and often essential, to lease space for their cables on telephone and electric utility poles. Utilities, in turn, have found it convenient to charge monopoly rents."); *see also* Common Carrier Bureau Cautions Owners of Utility Poles, 1995 FCC LEXIS 193, *1 (1995) ("Utility poles, ducts and conduits are regarded as essential facilities, access to which is vital for promoting the deployment of cable television systems"); FCC v. Florida Power Corp., 480 U.S. 245, 247 (1987) ("[I]n most instances underground installation of necessary cables is impossible or impractical. Utility company poles provide, under such circumstances, virtually the only practical physical medium for the installation of television cables.").

[2] Although witness Arnett testified that there are situations where there is more than one pole line in Blue Ridge's service territory, he was unable to give any estimate as to how prevalent that situation is. [Arnett, Tr. Vol. 3, pp. 10-11.]

of households per mile in Blue Ridge's service territory. [Mullins, Tr. Vol. 3, pp. 228-29.][1] Although witness Arnett argued that a facility may not be deemed to be an "essential facility" if it is replaceable, even at a much higher cost, he acknowledged that he may be mistaken as to how to define an essential facility. [Arnett, Tr. Vol. 3, p. 11.]

Witness Arnett did not employ any economic or cost-causation principles to support his opinion that Charter should equally share on a per-capita basis the costs of the unusable common space on a pole. Instead, he grounded his opinion in the overall benefit he asserted that Charter gains from using Blue Ridge's poles in the first place, as well as the equal benefit that he believes all pole users gain from use of the unusable space. [Arnett, Tr. Vol. 2, pp. 53-55, 84-87, 103-104.]. Witness Arnett suggested that the much higher cost to Charter of constructing its own facilities, rather than relying on attaching to Blue Ridge's poles, should be factored in by the Commission. [Arnett, Tr. Vol. 2, pp. 84-85.] Again, he chose not to address witness Kravtin's opinion that Charter has only limited and conditional rights of attachment.

Witness Kravtin testified about the damaging impact of excessive pole attachment rates on the market for communications services: "[E]xcessively high pole attachment rates operate like a non-cost based tax on the final or 'downstream' communications and broadband services bought by consumers." [Kravtin, Tr. Vol. 4, p. 175.] "Ultimately," she pointed out, "high pole attachment rates result in higher prices for communications services which in turn serve to reduce consumers' demand for and/or ability to pay for these services." [Kravtin, Tr. Vol. 4, p. 175.] She also testified that, in particular, higher pole attachment rates "discourage communications companies from making additional investment in the state and their ability to roll out, or continue to expand advanced broadband service offerings." [Kravtin, Tr. Vol. 4, p. 176.] She explained that the "dampening effect" of high pole attachment rates on broadband service deployment and adoption is especially serious in more rural and less densely populated areas due to the fact that these areas contain fewer potential customers per pole. [Kravtin, Tr. Vol. 4, p. 231.] In such areas, because there are relatively more poles necessary to serve a potential subscriber, the impact of high pole attachment rates is especially severe. [*See* Kravtin, Tr. Vol. 4, pp. 231-32.] The need for increased broadband deployment, in turn, has been recognized at both the national and state level, according to witness Kravtin's testimony. She noted that the FCC recently observed that it "has repeatedly recognized the importance of pole attachments to the deployment of communications networks." [Kravtin, Tr. Vol. 4, pp. 178-79 n.19.] Witness Kravtin testified that FCC Chairman Pai has emphasized that lower pole attachment rates are important "[t]o bring the benefits of the digital age to all Americans." [Kravtin, Tr. Vol. 4, pp. 178-79 n.19.] Witness Kravtin also said that the North Carolina Department of Information Technology is developing its own broadband plan to ensure affordable broadband access to sparsely populated areas. [Kravtin, Tr. Vol. 4, pp. 178-79 n.19.]

None of Blue Ridge's witnesses either debated the importance of broadband or argued that attachment rates may not be an important factor in a communications company's determination to expand its distribution plant in less populated areas. Nor did any Blue Ridge witness testify that lower Blue Ridge pole rates will have a significant effect on its electric rates. Witness Kravtin, on the other hand, testified that the impact of pole attachment revenues to total electricity revenues

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was, at most, very small. [Kravtin, Tr. Vol. 4, p. 176-77.][1] Witness Kravtin noted that EMCs already have a cost advantage over investor-owned companies due to the low interest loans that the former receive from the federal RUS. [Kravtin, Tr. Vol. 4, p. 181.] Cooperatives have available low-cost loans, and by their nature they do not have to pay the higher cost of raising public equity. [Kravtin, Tr. Vol. 4, p. 181.] Nevertheless, witness Kravtin testified that the FCC Rate methodology relies on a cost of money component that assumes the higher cost of equity applicable to IOUs, thus benefiting any cooperatives subject to pole attachment regulation pursuant to the FCC Rate Method. [Kravtin, Tr. Vol. 4, pp. 181-82 and n.21.]

With respect to comparing IOUs and cooperative utilities in other ways, witness Kravtin testified that EMCs "use the same type of plant, technology, and production techniques to provide electricity service to subscribers and in the same basic manner as IOUs." [Kravtin, Tr. Vol. 4, p. 212.] She and witness Martin also testified that IOUs and EMCs use poles that are indistinguishable. [Kravtin, Tr. Vol. 4, pp. 180, 196; Martin, Tr. Vol. 4, p. 77.] Witness Arnett testified that pole rates should be calculated based on economic cost allocation principles uninfluenced by the facts that Blue Ridge is a non-profit entity and that Charter is a large for-profit company. [Arnett, Tr. Vol. 3, pp. 46-47.]

Blue Ridge witness Layton testified that a Blue Ridge affiliate provides dark fiber services via facilities attached to Blue Ridge's poles. [Layton, Tr. Vol. 2, p. 9]. Witness Kravtin, moreover, testified that preventing pole owning electric utilities from charging excessive pole rates "has taken on heightened significance in recent years, with the increased opportunity of pole owning utilities to directly compete with communications attachers." [Kravtin, Tr. Vol. 4, p. 178.]

Discussion and Conclusions

While externalities and value of service principles associated with rates have seldom if ever been determinative, the Commission has considered both in past cases, at least in considering different classes of service. *See*, e.g., State ex. rel. Utilities Comm'n v. Durham, 282 N.C. 308, 314-15 (1972); Public Service Co. of North Carolina, Inc., Docket No. G-5, Sub 386, 1998 WL 941806, ¶ 57 (NCUC 1998). In this case the rate formulae advanced by the opposing parties are the FCC formula and the TVA formula. Even without considering externalities and value of service principles, the Commission determines that the FCC formula is based on valid and acceptable cost of service and cost allocation principles and the TVA formula is not. Nevertheless, N.C. Gen. Stat. § 62-350 directs the Commission, on a case-by-case basis in response to a dispute filed with the Commission, to set pole attachment rates that are "just and reasonable" and "consistent with the public interest." N.C. Gen. Stat. § 62-350(c). In considering whether a rate would be consistent with the public interest, it is appropriate to consider any externalities inherent in higher or lower pole attachment rates, as well as the impact of the rate on value of service principles.

Both parties presented testimony advocating pole attachment rates that rely, in some way, on the pole-related costs of Blue Ridge. The pole-related costs the parties believe should be factored into the rates directly as inputs are virtually identical. The principal difference between the parties relates to the appropriate allocation of those pole-related costs. As noted above, the

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economic analysis presented by witness Kravtin, Charter's expert, in support of a cost-based proportionate allocation of the costs of the common space is the sole economic testimony presented in the case. That analysis provides a solid basis on cost allocation principles in support of the FCC Rate formula. The Commission also concludes that the FCC formula finds additional support in the testimony regarding externalities and value of service principles.

The Commission agrees with witness Kravtin that there is a general benefit in the expansion of broadband service, and the Commission determines, as witness Kravtin asserts, that lower pole attachment rates would likely assist in the expansion of broadband service. In opposition to the economic principle that lower input costs are most likely to lead to expansion of output, Blue Ridge has presented no contrary economic evidence. In essence, witness Arnett simply argues that there is no assurance that lower pole rates in the range recommended by witness Kravtin will result in expanded broadband and that higher pole rates will reduce the cost of electricity to Blue Ridge's members. But witness Arnett did not even discuss, much less present any evidence of, the impact on electric rates of the lower pole attachment rate witness Kravtin recommends. Nor did witness Arnett provide any reason why the Commission should favor lower EMC electric rates over lower pole attachment rates in the public interest analysis under N.C. Gen. Stat. § 62-350 in any event. While lower electric rates, to the extent supported by evidence, might provide an arguable public interest benefit in support of higher pole attachment rates, the Commission cannot ignore the fact that the statute is primarily directed toward pole attachment, and not electric, rates. The Commission is confident that Blue Ridge does not intend to suggest that N.C. Gen. Stat. § 62-350 gives the Commission jurisdiction over cooperative electric rates.[1]

Further, the Commission finds convincing witness Kravtin's testimony that the purpose of pole attachment regulation is to control the natural incentive for monopoly owners of essential facilities to overcharge. The history of pole attachment regulation at the federal level and in other states has been directed toward that goal, and the Commission has been made aware of no different objective on the part of the General Assembly in passing and amending N.C. Gen. Stat. § 62-350. Although witness Arnett contends that poles are not an "essential facility" to Charter, the evidence shows that it would be prohibitively expensive and infeasible for Charter to transfer its existing aerial facilities underground.[2] The Commission has no basis in the record, therefore, to depart from the many prior decisions finding that poles are "essential" monopoly facilities to communications service providers.[3] Moreover, with respect to the argument between the parties

[1] The fact that electric cooperatives are formed, in part, to "mak[e] electric energy available to inhabitants of the State at the lowest cost consistent with sound economy and prudent management," N.C. Gen. Stat. § 117-10, has no bearing on the Commission's mandate under N.C. Gen. Stat. § 62-350 to adjudicate just and reasonable pole attachment rates. If the General Assembly intended the Commission to prioritize low electric rates in adjudicating disputes over pole attachment rates, it would have said so explicitly. The Commission assumes that any such intention would have to be accompanied by some regulatory authority by the Commission over those electric rates so that the Commission could evaluate whether a reduction in pole attachment rates could properly be off-set by reduction of expenses or a more efficient electric delivery operation.

[2] The testimony of Blue Ridge's witnesses that some ILECs have found it possible to remove some aerial facilities and place them underground does not counter the infeasibility for Charter to move all of its facilities off of Blue Ridge's poles at a cost of more than $56 million. [Mullins, Tr. Vol. 3, p. 228.] Charter's witnesses testified that it would be "prohibitively expensive." [Mullins, Tr. Vol. 3, p. 227.]

[3] *See* Otter Tail Co. v. United States, 410 U.S. 366, 378 (U.S. 1973) (finding that for practical reasons, "[i]nterconnection with other utilities is frequently the only solution."); FCC v. Florida Power Corp., 480 U.S. 245,

over whether Blue Ridge's poles are essential facilities and thus providing entitlement for communications providers to attach on that basis, the Commission concludes that the North Carolina General Assembly has effectively preempted that debate. N.C. Gen. Stat. § 62-350 requires that "a membership corporation . . . shall allow any communications service provider to utilize its poles" at rates determined by the Commission to be just and reasonable. Neither the right to attach nor the attachment rate is triggered by any finding that the poles are "essential facilities."

In addition, the Commission does not find that the non-profit nature of Blue Ridge presents any compelling argument for higher pole attachment rates. The poles owned by Blue Ridge are fundamentally the same as the IOU- and telephone company-owned poles that Charter also relies on in North Carolina and that are subject to the FCC pole attachment rate formula. In addition, IOUs and cooperatively-organized electric utilities operate the same types of facilities to provide the same services. The only meaningful difference identified by the parties is that, as witness Kravtin testified, EMC costs are lower than IOU costs, in particular because cooperatives have access to money at a lower cost. Nevertheless, witness Kravtin's use of the FCC Rate formula involves an acceptance of a default annual rate of return of 11%, which is intended to reflect a blended overall cost of both equity and debt. Even the TVA, which has adopted a rate formula intended to be very favorable to its wholesale electric customers, relies on a lower rate of return (8.5%). The Evidence and Conclusions for Finding of Fact No. 33 addresses Blue Ridge's argument that it should also be allowed to recover additional "but for" costs separately from the pole rental rate, but that analysis is no different for investor-owned or cooperatively-organized utilities. The Commission is thus confident that the FCC Rate formula fairly allocates pole costs of nonprofit cooperatives in exactly the same way it does for investor-owned utilities.

It is possible to characterize witness Arnett's focus on the benefits that Charter receives from being able to attach to Blue Ridge's poles as a value of service analysis. The Commission has, on occasion, looked to value of service as a factor to be considered in rate design for different classes of customers, traditionally as a downward constraint on rates recognizing that certain classes of consumers may have substitute service available in some situations. See, e.g., State ex. rel. Utilities Commission v. Durham, 282 N.C. 308, 314-15 (1972); *Order Granting Partial Rate Increase*, Docket No. G-5, Sub 386, 1998 WL 941806, ¶ 57 (NCUC 1998). The Commission, however, has never applied the concept to increase the rates paid by customers on the basis that the service is particularly "valuable" to the consumer. Nor has the Commission ever set a customer's rate based on the "value" to the customer of avoiding the prohibitive cost of providing the utility service to itself, as opposed to relying on the utility's provision of the service, as witness Arnett suggests. In any event, traditional value of service principles are inapplicable here, where the Commission is not asked to design rates for different classes of customers and the record evidence indicates Charter does not have viable substitutes to attaching to poles owned by Blue Ridge and in light of the prohibitive cost of relocating its existing aerial network underground.

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247 (1987) ("[I]n most instances underground installation of necessary cables is impossible or impractical. Utility company poles provide, under such circumstances, virtually the only practical physical medium for the installation of television cables."); MCI Commc'ns Corp. v. Am. Tel. and Tel. Co., 708 F.2d 1081, 1133 (7th Cir. 1983) (facilities were essential where "[i]t would not be economically feasible . . . to duplicate . . . local distribution facilities"). The evidence in this case does not establish that Charter would have any viable and economic alternative to attaching to large numbers of Blue Ridge's poles.

As a final comment, the Commission notes that, in the hearing and its post-hearing filings, Blue Ridge implores the Commission to "disregard Charter's illusory promises that [Charter] will extend broadband if awarded a low pole attachment rate." Blue Ridge's Post Hearing Brief, p. 3. The Commission has not acceded to that request. Instead, as the text above indicates, the Commission has chosen to accord substantial weight to witness Kravtin's expert opinion that lower pole attachment rates would likely assist in the expansion of broadband service. While as a matter of economic theory, witness Kravtin's assertion in this regard is undoubtedly true, it provides no solace to Blue Ridge because it is not supported by any hard or quantifiable data from Charter or for that matter any other communications service provider that demonstrates conclusively that the lower pole attachment rates has led to the expansion of broadband it its territory. Thus, in this and other pole attachment proceedings that may come before this Commission in the future, the Commission looks forward to quantifiable data being presented to the Commission by Charter and other communications service providers which will support this opinion. For that to happen, Charter and other communications service providers would have to do more than just talk the talk when they come before the Commission seeking to use the FCC rate methodology, which was purposely designed by Congress and the FCC to produce low rates to encourage the expansion of cable/ broadband. (While the FCC was statutorily mandated to structure this low rate to encourage the expansion of cable and broadband, this Commission has no such mandate. This Commission is charged with developing just and reasonable rates and protecting the public interest.) Indeed, they will have to walk the walk. That is, Charter and every other communications service provider that advances this assertion should now commit to and follow through with the commitment to expand broadband in the areas served by customers similar to those residing in Blue Ridge's territory in return for this low rate. If they fail to do so, Blue Ridge's assessment that Charter's promise of broadband service in exchange for a lower FCC rate is illusory would prove to be correct. Without quantifiable data, this Commission is unlikely to accord any weight to such empty promises in the future.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 21-22

The evidence presented in support of these Findings of Fact has been discussed above.

Discussion and Conclusions

Based on the evidence in the record in this docket, the Commission concludes that the FCC Rate Methodology should be used to set Blue Ridge's maximum pole attachment rate. The FCC formula is longstanding, well-understood, widely applied, and judicially approved. It is employed in the vast majority of states, including for the electric IOUs and telecommunications ILECs in North Carolina. It has been found by the U.S. Supreme Court to be fully compensatory. It relies on the well-accepted economic theory that common or indirect costs are appropriately allocated on the same basis as direct costs are incurred and assigned. Applying it here to cooperative pole owners like Blue Ridge would bring uniform treatment to most poles in the state, avoiding in large part the anomaly of having widely varying rates for virtually identical poles which are placed in a pole line side by side.[1]

[1] Blue Ridge argues that the Commission cannot achieve uniform treatment through adoption of the FCC Rate Methodology because three EMCs in North Carolina purchase their electric power from the TVA and thus the

In contrast, the TVA pole attachment rate method is new and untested and, so far as presented in this case, without any basis in economic theory. Its reliance on a per-capita allocation of the cost of the unusable common space results in widely varying rates even where the underlying costs are themselves similar, and produces the highest rates in rural areas where high rates can have the most pernicious impact.

No evidence was presented to the Commission that Blue Ridge requires a continuation of pole attachment rates in the range it has been charging. The pole attachment rates that Blue Ridge has been charging Charter are substantially higher than the rates that Blue Ridge has been charging other pole attachers,[1] [Martin, Tr. Vol. 3, p. 225; see MM Exs. 9-14], and Blue Ridge's pole attachment revenues are a tiny fraction of its electric revenues.

The rate methodologies relied on by Blue Ridge in support of the TVA method are not only different from that method, they have had very limited application. Furthermore, Blue Ridge has not made a convincing case for the proposition that Charter should share equally on a per-capita basis the costs of the unusable space. Charter has only limited, conditional and potentially temporary rights to occupy Blue Ridge's poles, and it is wholly responsible for paying to create or preserve the limited amount of pole space that it uses. For this reason, it does not share the benefits of using any portion of the pole equally with Blue Ridge.

In some respects, the pole attachment service provided to Charter by Blue Ridge is like interruptible electric service, which generally is provided at rates well below standard rates.[2] *See, e.g.,* State ex. rel. Utilities Commission v. Durham, 282 N.C. 308, 308 (1972) (noting that "interruptible customers pay at a substantially lower rate than the firm customers".); Order on Petition for Limited Waiver of Rate Schedule 106 Billing Procedures, Docket No. G-9, Sub 649, (NCUC Oct. 29, 2014) (reciting evidence that Piedmont's interruptible transportation customers paid between 28.6% and 36.3% less than firm customers for the first 15,000 therms of service; concluding that "in exchange for agreeing to curtail their service Piedmont's interruptible customers pay substantially lower rates than Piedmont's firm transportation customers."); Federal Energy Regulatory Commission, Cost of Service Rates Manual 41 (1999), available at https://www.ferc.gov/industries/gas/gen-info/cost-of-service-manual.doc ("[P]aying the lowest unit rate that a firm shipper could pay for firm service, appropriately recognizes the inferior quality of interruptible service."). As with interruptible electric service, the evidence here reflects that Blue Ridge does not incur capital investment to provide Charter with pole attachment service. Instead, Charter is entitled to make pole attachments only to the extent that pole space is available and not required for Blue Ridge's own facilities. Charter's service rights are even more limited

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TVA sets their pole attachment rates. Nevertheless, the Commission's decision to rely on the FCC Rate Methodology in the state will mean that the vast majority of poles in the state are regulated according to the same rate methodology.

[1] Blue Ridge charged Charter the highest annual pole attachment rate of any third party attacher. The annual rate that Blue Ridge has imposed on Charter is more than double the rate that Blue Ridge has imposed on Charter's direct competitor, SkyBest. [Martin, Tr. Vol. 3, p. 225.] While Blue Ridge explains the former disparity by noting that the majority of these agreements are with joint users, it has yet to provide a satisfactory explanation of this disparate treatment between Charter and SkyBest, another third party attacher and a direct competitor of Charter.

[2] In "interruptible" service, the customer is entitled to service only to the extent that it is not necessary to serve another customer. The "interruptible" service customer understands that its service may be interrupted if necessary to serve a regular customer.

than those of an interruptible service customer because Charter itself absorbs any necessary capital expenditures in connection with making space on Blue Ridge's poles, yet continues to pay for the service thereby made possible.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 23-30

The evidence supporting these Findings of Fact is found in the testimony of witnesses Arnett and Kravtin.

The FCC Rate Methodology employs rebuttable presumptions regarding the height and use of a utility's poles, which include presumptions that: (i) the average height of a distribution pole is 37.5 feet; (ii) these poles are, on average, buried six feet deep, and (iii) in order to maintain proper clearances, the lowest attachment on a pole must be at least 18 feet off the ground. In applying the FCC Rate Methodology, the FCC treats these presumptions as rebuttable by either party.[1] The TVA Rate Methodology also employs presumptions that may be rebutted.

Witness Arnett offered testimony and calculations in support of an argument that Blue Ridge should be permitted to rebut each of these factual presumptions. [Arnett, Tr. Vol. 2, pp. 60-61.] He testified that the average Blue Ridge pole is 36.83 feet, 36.85 feet and 36.87 feet for 2014, 2015 and 2016 respectively. [Arnett, Tr. Vol. 2, pp. 61-62.] In rebutting the presumption that the average pole is 37.5 feet long, he looked to the continuing property records of all of Blue Ridge's distribution poles in Account 364. [Arnett, Tr. Vol. 2, pp. 61-62, 187-88.] He determined that the average amount of unusable space on those poles is 27.3 feet, 27.28 feet and 27.26 feet for the years 2014, 2015 and 2016 respectively by estimating that the average mid-span clearance requirement for the lowest communications cable would be 15.5 feet, by calculating the average span length between poles and the expected "sag" of the lowest communications cables, and by assuming that poles are buried 6 feet in the ground. [Arnett, Tr. Vol. 2, pp. 63-65.] He then determined that an average Blue Ridge pole has 9.53 feet of usable space for 2014, 9.57 feet of usable space for 2015 and 9.61 feet of usable space for 2016 by subtracting his unusable space calculation for each year during the subject period (27.26 feet) from his average pole height (36.87 feet).

In addition to the aforementioned, he also testified about and attempted to rebut or refine the following presumptions that the FCC relied upon in developing the FCC Cable Rate Methodology. Although he accepted the FCC/TVA presumption that communications attachments occupy one foot of usable space, he determined that Charter has an average of 1.1 attachments on those Blue Ridge poles to which it is attached. [Arnett, Tr. Vol. 2, p. 63.] Based on Blue Ridge's continuing property records, he determined that the percentage of the pole investment account (Account 364) consisting of "appurtenances" is 12.59%, rather than the presumed 15%. [Arnett, Tr. Vol. 2, pp. 61-62.] And, finally, based on a survey, Blue Ridge has an average of only 2.35 entities attached to its poles. [Arnett, Tr. Vol. 2, p. 60.] By utilizing the aforementioned figures, witness Arnett calculated that the maximum pole attachment rate utilizing the modified

[1] See 47 C.F.R. § 1.1418 which provides that with respect to the FCC Cable Rate Methodology: "the space occupied by an attachment is presumed to be one (1) foot. The amount of usable space is presumed to be 13.5 feet. The amount of unusable space is presumed to be 37.5 feet. These presumptions may be rebutted by either party."

FCC Rate Methodology should be (a) $8.49 for rate years 2015, (b) $8.37 for rate year 2016, and (c) $8.31 for rate year 2017. *See* Exhibit WA-33 (providing calculations).

In her testimony, witness Kravtin stated that the Commission should set rates using the FCC Rate Methodology's "presumptions," rather than actual data regarding Blue Ridge's pole plant, because those presumptions are "generically applicable" and "streamline the formula process." *See* Kravtin Tr. Vol. 4, p. 188. Her position, however, directly contradicts her own testimony where she states:

> ***As with any presumptive value in the formula, to the extent there is actual (or statistically significant) utility or attacher specific data to support use of alternative space presumptions those can be used in lieu of the FCC's established space presumptions.*** So, for example, if actual data exists to support use of a 35-foot joint use pole with 11 feet of usable space and 24 feet of unusable space, the space allocation factor would be 1/11 or 9.09%.

Kravtin Tr. Vol. 4, pp. 187 (emphasis added).

By ignoring Blue Ridge's actual data and applying the FCC Rate Methodology's presumptions, witness Kravtin calculated the following maximum attachment rates of $5.22 for rate year 2015, $5.20 for rate year 2016 and $5.18 for rate year 2017.

Discussion and Conclusions

In its Post Hearing Brief and Proposed Order, Charter argued that the Commission should reject Blue Ridge's attempts to rebut the presumptions that the FCC (and the TVA) relied upon in the FCC/TVA formulae because: (1) witness Arnett designed his own methods for rebutting the presumptions, (2) the TVA has not offered any guidance on how presumptions employed in the pole attachment formula should be rebutted, (3) the FCC has offered guidance on how the presumptions employed in the FCC formula should be rebutted and witness Arnett has failed to comply with that guidance, and (4) Blue Ridge cherry picked and rebutted only those presumptions that benefitted Blue Ridge. While it is not entirely clear from the aforementioned, it appears that the crux of Charter's argument is that the Commission should reject witness Arnett's evidence because: (1) he designed his own methods for rebutting the FCC Rate Methodology's presumptions, and (2) witness Arnett's method did not comply with FCC decisions and guidelines. There is no merit to these arguments.

When Congress enacted Section 224 of the federal Pole Attachment Act of 1978, it specifically exempted EMCs from regulation by the FCC. Prior to 2009, EMC pole attachment rates were not subject to regulation in North Carolina. The General Assembly enacted N.C. Gen. Stat. § 62-350 in 2009. In the 2009 version of the statute, the General Assembly placed responsibility for resolving pole attachment disputes with the North Carolina Business Court. The General Assembly amended the statute in 2015 to grant this Commission exclusive jurisdiction to resolve disputes arising under the statute. When determining a pole attachment dispute filed pursuant to N.C. Gen. Stat. § 62-350, the Commission may, in its discretion "consider any evidence or rate-making methodologies offered or proposed by the parties" in making its decision regarding the just and reasonable rates by which a communications service provider shall be able to attach to an EMC's poles. N.C. Gen. Stat. § 62-350. Further, in making that determination, the Commission "shall apply the rules of evidence applicable in civil actions in the superior court [in these actions], in so far as practicable." N.C. Gen. Stat. § 62-65.

In this docket, the Commission has determined that it is proper for the pole attachment rates in this case to be determined by using the FCC Rate formula. FCC regulations specifically permit the following three presumptions employed in the FCC formula to be rebutted by either party: (1) that the space occupied by an attachment is one foot; (2) that the amount of usable space is presumed to be 13.5 feet; and (3) that the amount of unusable space is presumed to be 37.5 feet. And, North Carolina law permits any presumption employed in the formula other than a conclusive presumption to be rebutted. <u>Brandis & Broun on North Carolina Evidence</u>, Sixth Edition, Section 44, footnote 191, p. 149. None of the presumptions employed in the FCC Rate Methodology are conclusive. Thus, under North Carolina law, the presumptions used in the FCC and the TVA rate formulas may be rebutted.

Here, witness Arnett testified that Blue Ridge has actual data that should be used in lieu of the permissive presumptions employed in the FCC and the TVA formulas to calculate the maximum pole attachment rate. As previously noted, during the hearing, witness Arnett presented evidence to the Commission which he contended better reflected Blue Ridge's actual system data. The evidence was presented <u>without objection</u>. The evidence is admissible. It is relevant and, it is material. Thus, the only real issue with regard to witness Arnett's testimony is whether this evidence is sufficient to persuade the Commission that it is accurate and that it can and should be utilized in the FCC formula in lieu of the presumptions employed by the FCC to determine the maximum pole attachment rate applicable in this proceeding.

The Commission has carefully considered the evidence presented in this proceeding by witness Arnett to rebut the FCC's presumptions as well as the flaws in that evidence detailed in Charter's post hearing filings. In evaluating witness Arnett's testimony and the flaws identified by Charter, the Commission is mindful that Charter witness Kravtin stated that "[a]s with any presumptive value in the formula, to the extent there is actual (or statistically significant) utility or attacher specific data to support use of alternative space presumptions, those can be used in lieu of the FCC's established space presumptions." [Kravtin Test, Vol. 4, pp. 187.] Further, the Commission is mindful that witness Arnett has fifty plus years of experience with pole attachment issues, and that he had 17 plus years in BellSouth's engineering department performing and managing all aspects of BellSouth's <u>outside plant</u> engineering. This experience has given him particular insight which he used to develop <u>actual</u> or statistically significant utility or attacher specific data <u>in this case</u>. (The depth of witness Arnett's expertise in these matters is illustrated by the following colloquy between witness Arnett and Mr. Gillespie:

> Q. Do you know the guidance the FCC has given regarding the information that you need to rebut the presumption that there's 13.5 feet of usable space on the pole?
>
> A. No, sir, but I know how to calculate that.

> Q. My question was whether you've gotten any guidance from the FCC according to what are discussed what you need to look to, what information you need in order to rebut that presumption.
>
> A. I did those kinds of calculations whenever I was in the engineering department at Southern Bell and Bell South for their communications cables. We routinely calculated the point of attachment and those points of attachment were almost never on an electric co-op pole 18 feet.

Emphasis added. Tr. Vol. 2. pp.197-198.) The Commission finds his expertise in these matters particularly persuasive in this case.

In light of the aforementioned and after duly considering that evidence and the record proper, the Commission finds by the greater weight of the evidence in this case that witness Arnett has presented actual, credible and statistically significant specific data which should be used in lieu of the FCC's established space presumptions in calculating the maximum pole attachment rates that should apply in this case. Further, the Commission finds and concludes that such a finding is consistent with the statutory directive that the Commission consider each case filed under N.C. Gen. Stat. § 62-350 on a "case by case basis" and that the Commission "consider any evidence or rate-making methodologies offered or proposed by the parties" in making its decision. As noted above, by applying Blue Ridge's actual data in the FCC rate formula, the following rates result: (a) $8.49 for rate year 2015, (b) $8.37 for rate year 2016, and (c) $8.31 for rate year 2017.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 31-32

The evidence supporting these Findings of Fact is found in the testimony of witnesses Arnett, Kravtin and Mullins, and the Joint Stipulations, agreed to by both parties.

Witness Arnett calculated Blue Ridge's pole attachment rates for the years 2015-2017 according to the FCC Rate Methodology, based on cost data provided by Blue Ridge. He calculated Blue Ridge's annual rates as follows:

2015 - $8.49
2016 - $8.37
2017 - $8.31

The uncontradicted testimony is that Charter paid the following rates for 2015 through August 2017:

2015 – $26.64
2016 - $26.64
2017 – $26.64

[Joint Stipulations ¶¶ 8-10.][1]

[1] ***BEGIN CONFIDENTIAL*** ***END CONFIDENTIAL***

Blue Ridge commenced an effort to negotiate a new pole attachment agreement with Charter on May 22, 2014 by notifying Michael Mullins at Charter that the 2008 Agreement between the parties had expired and sending Charter a draft agreement to start negotiations. [Layton, Tr. Vol. 1, p. 36.] Charter responded with a redlined draft on May 26, 2015, and the negotiations were joined. [*See* MM Ex. 3; Mullins, Tr. Vol. 3, p. 237; Layton, Tr. Vol. 1, p. 37.] The parties were unable to reach an agreement on a new pole attachment agreement, and the 90-day negotiating period under N.C. Gen. Stat. § 62-350 was complete as of August 25, 2015. Charter has paid Blue Ridge at the $26.24 rate through August 2017. [Joint Stipulations ¶ 10.] During this period of time, the 2015-16 Inventory found that Charter had 27,674 attachments to 24,888 Blue Ridge poles. [Joint Stipulations ¶ 12.]

Discussion and Conclusions

Blue Ridge contends that Charter's counterclaim requesting that the Commission require Blue Ridge to refund the difference between the pole attachment rates that Charter paid Blue Ridge to continue attaching to Blue Ridge's poles in 2015, 2016 and 2017 and the rates that the Commission determines that Charter should have been paying during those periods should be denied because a close reading of N.C. Gen. Stat. § 62-350(c) indicates that the Commission is "not authorized to apply rates retroactively when the parties are operating under an existing agreement." Blue Ridge Proposed Order, p. 65. Blue Ridge's core argument is that the parties have an "existing agreement" and that, by statute, any new rate that the Commission determines in that circumstance should be applied "prospectively" from the date that the Commission issues an order. There is no merit to this argument.

At the outset, the Commission notes that Blue Ridge is essentially arguing that Charter waived its right to seek recovery for overpayments that it allegedly made to Blue Ridge during the periods in question by agreeing to extend the term of the 2008 Agreement [1] or that it is statutorily estopped and/or "bar[red]" [2] from pursuing this claim because of that act. Waiver, bar and estoppel are affirmative defenses which were required to be set forth in Blue Ridge's response to Charter's Counterclaim. N.C. Gen. Stat. § 1A-1, Rule 15(c). As such, these affirmative defenses must be pled with certainty and particularity and established by the greater weight of the evidence. Duke University v. Saint. Paul Mercury Insurance Company, 95 N.C. App. 663, 673, 384 S.E. 2d 36, 42 (1989).[3] "Failure to raise an affirmative defense in the pleadings generally results in a waiver thereof." Robinson v. Powell, 348 N.C. 562, 566, 500 S.E.2d 714, 717 (1998).

Blue Ridge's pre-hearing responses and pleadings did not set forth any affirmative defenses to Charter's counterclaims. Nor did Blue Ridge present any evidence during the hearing itself from which one could infer that Blue Ridge believed that it had an affirmative and/or statutory defense

[1] The 2008 Agreement terminated on September 1, 2013.

[2] "Charter's stipulation and admissions that the 2008 Agreement remains in place—bar it from seeking 'true-up' payments under G.S. 62-350." Emphasis added. Blue Ridge Post-Hearing Brief, p. 9.

[3] This specificity requirement is consistent with the pleading requirements set forth in N.C. Gen. Stat. § 62-350(c) which provides in pertinent part that: "The parties shall identify with specificity in their respective filings the issues in dispute." Emphasis added. The Commission's Order Requiring Pretrial Filing also required the parties to file: "3. A clear and concise listing and statement of each issue in dispute."

to Charter's counterclaims. Arguably, Blue Ridge has waived its right to assert these defenses by its failure to set forth these defenses with particularity and certainty prior to its post-hearing filings. Assuming arguendo, however, that Blue Ridge did not waive these defenses by failing to plead them prior to its post-hearing pleadings, its argument that Charter is barred from recovering these alleged overpayments by a close reading of N.C. Gen. Stat. § 62-350(c) lacks merit.

In pertinent part, N.C. Gen. Stat. § 62-350(c) states:

> The Commission shall apply any new rate adopted as a result of the action retroactively to the date immediately following the expiration of the 90-day negotiating period or initiation of the proceeding, whichever is earlier. If the new rate is for the continuation of an existing agreement, the new rate shall apply retroactively to the date immediately following the end of the existing agreement. Emphasis added.

As previously noted, the core of Blue Ridge's argument is that the Commission is "not authorized to apply rates retroactively when the parties are operating under an existing agreement and that, by statute, any new rate that the Commission determines in that circumstance should be applied "prospectively" from the date that the Commission issues an order. Blue Ridge Proposed Order, p. 65. Blue Ridge's argument is, on its face, inconsistent with the statute. That is, the text of the statute does not contain any reference to a prospective application. Nor does the text of the statute indicate that, under the circumstances described therein, the new rate shall apply "prospectively from the date of the order." Blue Ridge Proposed Order, p. 67. Instead, by its clear terms, the pertinent text of N.C. Gen. Stat. § 62-350(c) states that "[i]f the new rate is for the continuation of an existing agreement, the new rate shall apply retroactively to the date immediately following the end of the existing agreement." Emphasis added.

Under the terms of the 2008 Agreement, that agreement ended on September 1, 2013. See footnote 58, Charter Proposed Order, Public Version, p. 43. Thus, the 2008 Agreement ceased to exist on that date. Blue Ridge acknowledged this fact on numerous occasions. See Testimony, Lee Layton, Tr. Vol. 1, p. 36, footnote 2, Blue Ridge Brief, pp. 4-5. *****BEGIN CONFIDENTIAL***** *****END CONFIDENTIAL***** Because the 2008 Agreement ceased to exist on September 1, 2013, N.C. Gen. Stat. § 62-350 would not apply and could not be interposed to bar Charter from collecting for any alleged overpayments that it made after the expiration date of the agreement.

Moreover, if the 2008 Agreement did in fact continue in existence as Blue Ridge contends, under the plain text of the statute, any new rate determined by this Commission in this docket would apply retroactively to September 1, 2013, the only end date specified in the 2008 Agreement. Applying the statute in accordance with this literal interpretation [1] is problematic

[1] The pertinent provision in N.C. Gen. Stat. § 62-350(c) provides that "if the new rate is for the continuation of an existing agreement, the new rate shall apply retroactively to the date immediately following the end of the existing agreement." By its clear terms, this provision is intended to facilitate "the continuation of an existing agreement" by resolving a rate dispute. Thus, this provision only applies when there is unanimity between the parties that the current terms and conditions in an existing agreement should continue to apply and will continue to apply once the Commission resolves the rate issue. In that situation, the only dispute between the parties that the Commission should be requested to resolve is the rate dispute. That is not the case here because Blue Ridge and Charter seek Commission approval to change the terms and conditions that have previously governed the parties' operations. Therefore, N.C. Gen. Stat. § 62-350(c) does not apply in this circumstance.

for Blue Ridge because it would increase rather than decrease Blue Ridge's potential liability because Charter would be able to seek recovery for payments made since that September 1, 2013 expiration date instead of August 25, 2015, i.e., the date that Charter alleges that the 90-day negotiation period expired and that its recovery right began.

To avoid this literal application of the statute, Blue Ridge here contends that not only did the parties (implicitly) agree (in 2015) to continue operating under the terminated 2008 Agreement, but that they also agreed that the 2008 Agreement would not end until this Commission issues an order in this docket.[1] While there is abundant evidence in the record that Charter agreed to operate pursuant to the "expired" 2008 Agreement,[2] Blue Ridge has not cited to any document or discussion in the record proper where Charter specifically agrees that the term of the "expired" 2008 Agreement would be extended until the date that the Commission issues an order in this dispute.[3] In fact, the documentary evidence in this proceeding indicates only that the parties agreed to continue operating under the terms of the "expired" 2008 Agreement for a limited term which was and is well short of the date of this order.[4] Operating "under" or "pursuant to" the terms of an expired agreement is not the same as and does not mandate an interpretation or finding that the term, i.e., length of the agreement, was extended.

Moreover, even if one assumes arguendo that the parties agreed that the term of the agreement would be extended until the date that the Commission issues an order in this docket, N.C. Gen. Stat. § 62-350(c) would not bar Charter's overpayment recovery because the revival of the expired 2008 Agreement and the extension of its term do not result in the "continuation of the existing agreement." Instead, it results in the formation of a "new" agreement with different terms and conditions including a new expiration date. See, Lewis v. Edwards, 147 N.C. App. 39, 554 S.E.2d 17(2001). The cited sentence in N.C. Gen. Stat. § 62-350(c) does not apply to this newly formed agreement.

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[1] See Paragraph 72, Blue Ridge Proposed Order, p. 67, where Blue Ridge states: "Because Charter is operating under an existing pole attachment agreement with Blue Ridge, it is not entitled to recover retroactive "true up" payments based on the rate the Commission ultimately adopts. Instead, pursuant to Section 62-350, the rate the Commission adopts will only apply prospectively from the date of this order. Charter's counterclaim for "true up" payments retroactively applying the rate the Commission adopts back to 2015 therefore should be denied." The crux of this argument is that the parties must have agreed and/or understood that N.C. Gen. Stat. § 62-350 would provide for an expiration date different from the date set forth in the 2008 Agreement when they agreed to continue operating pursuant to the terms of that agreement and that the expiration date would be the date that the Commission issues an order in this docket.

[2] For instance, Blue Ridge made the following statements as support for its position: "it is undisputed that Charter has continued to attach to Blue Ridge's poles pursuant to the 2008 Agreement and thus agreed to *continue its term* through continued performance." Blue Ridge's Post Hearing Brief, p. 8. Further, Blue Ridge stated: In addition to stipulating that it continues to attach to Blue Ridge's poles "pursuant to" the 2008 Agreement, see Joint Stipulations, [] the evidence makes clear that Charter has agreed through its conduct to continue operating under the 2008 Agreement, even after the expiration of the original term." Blue Ridge's Proposed Order, p. 66.These are Blue Ridge's words and not Charter's.

[3] In Paragraph 6 of the Joint Stipulations, the parties stipulated that: "Charter attaches and has facilities attached to Blue Ridge's utility poles pursuant to a Pole Attachment Agreement dated September 1, 2008."

[4] ***** BEGIN CONFIDENTIAL*** *** END CONFIDENTIAL*****

When the parties continue to operate based upon this newly formed agreement and initiate and/or follow through on previously begun negotiations as a result thereof, the first sentence in N.C. Gen. Stat. § 62-350(c) applies. It provides that "[t]he Commission shall apply any new rate adopted as a result of the action retroactively to the date immediately following the expiration of the 90-day negotiating period or initiation of the proceeding, whichever is earlier." See the first sentence in N.C. Gen. Stat. § 62-350(c). Here, the 90-day negotiating period expired on August 25, 2015 and Blue Ridge filed the complaint initiating this action on November 30, 2016. Thus, pursuant to this language, Charter is entitled to seek reimbursement for alleged overpayments since August of 2015.

In addition to the aforementioned, Blue Ridge also argues that Charter is statutorily "barred" [1] from recovering any "overpayments" that it made to Blue Ridge while the parties continued to operate under the 2008 Agreement. Blue Ridge's argument in this regard is dependent upon the language in N.C. Gen. Stat. § 62-350, Charter's subsequent conduct after the 2008 Agreement expired and the parties' stipulation.

With regard to the former, N.C. Gen. Stat. § 62-350 did not exist in 2008. It was enacted by the General Assembly in 2009, long after the parties had reached the 2008 Agreement. For this reason, the 2008 Agreement did not include and could not have included a specific reference to the yet to be enacted provisions in N.C. Gen. Stat. § 62-350. Perhaps an agreed upon change of law provision may have incorporated subsequent changes in relevant law such as the enactment of N.C. Gen. Stat. § 62-350 into the 2008 Agreement, but no such provision was included in the 2008 Agreement. Thus, the terms of N.C. Gen. Stat. § 62-350 could not have been included in the Agreement unless the Agreement itself was specifically modified by the parties at some date subsequent to the effective date of the Agreement.[2]

The later inclusion of such a provision in the parties' agreement would have necessitated the agreement of both parties as well as additional consideration. Neither party produced a written and/or signed document where the parties agreed to this specific term. Neither party produced any direct evidence or testimony where the parties explicitly discussed and agreed to that specific term. And, neither party produced any evidence that any additional consideration was provided in support of this modification. Instead, Blue Ridge cites to the parties' stipulation (and conduct) and asks this Commission to infer that Charter has agreed (or should be deemed to have agreed) to be bound by this "new" term in the 2008 Agreement.

[1] See Blue Ridge's Post-Hearing Brief, p. 9. "Charter's stipulation and admissions that the 2008 Agreement remains in place—and that it is subject to an existing pole attachment agreement—bar it from seeking 'true-up' payments under G.S. 62-350."

[2] It is noteworthy that, at the time when the parties agreed to continue operating under the terms of the terminated 2008 Agreement, i.e., in 2015, the status of N.C. Gen. Stat. § 62-350 itself was uncertain. Blue Ridge acknowledged this uncertainty when it proposed that the parties continue to operate under the expired 2008 Agreement. See MM Ex 4 and LL-5 where Blue Ridge acknowledged that "the [General Assembly might] add other provisions to guide [the parties'] negotiations." MM Ex 4 and LL-5. Thus, because of this uncertainty, even if the Commission could find that the parties are operating under an "existing" agreement, the Commission could not and cannot conclude that Charter was bound by the statutory provision cited by Blue Ridge without compelling evidence that Blue Ridge specifically agreed that this provision would apply. No such evidence has been presented.

While N.C. Gen. Stat. § 62-69 allows the Commission to resolve any proceeding by stipulation, the Commission may not extend the agreed upon stipulation beyond the limits set by the parties. Utilities Commission v. CUCA, Inc., 348 N.C. 452, 500 S.E.2d 693 (1998). The Parties' joint stipulation states: "Charter attaches and has attached to Blue Ridge's utility poles pursuant to a Pole Attachment Agreement dated September 1, 2008." The text of the stipulation clearly indicates that the parties agreed to continue operating under the 2008 Agreement. It does not, however, indicate that the parties agreed to or stipulated that the alleged overpayments made pursuant to the agreement could not be recovered by Charter because of N.C. Gen. Stat. § 62-350.

The same is true of Charter's conduct. While Charter's conduct indicates that it agreed to continue operating under the terms and conditions of the 2008 Agreement, one could not fairly conclude from that conduct that by continuing to operate under the terms of the 2008 Agreement, Charter understood and agreed that it was forgoing its rights to recovery of any alleged overpayments. In fact, Charter's pursuit of this claim in this proceeding is a rather strong indication that it did not and does not believe that it agreed to be statutorily barred from recovering any alleged overpayments either by agreeing to operate under the 2008 Agreement or by agreeing to the stipulation. Therefore, without more, the Commission cannot reasonably conclude from Charter's conduct and stipulation that Charter agreed to and/or understood that it would be statutorily precluded from seeking repayment for any alleged overpayments. Were the Commission to do so, the Commission would extend the agreed upon stipulation beyond the limits set by Charter and Blue Ridge and/or draw an unreasonable inference from Charter's conduct. Thus, for this reason and the reasons previously articulated, the Commission concludes that N.C. Gen. Stat. § 62-350(c) does not prevent Charter from pursuing recovery for overpayments that it can prove that it has made in this proceeding simply because it agreed to continue operating under the terms of the 2008 Agreement. Charter is therefore entitled to pursue recovery for any overpayments that it is alleged to have made.

The only remaining issue in this regard is the starting date that Charter should be allowed to begin recovering for any alleged overpayments that it made to Blue Ridge. N.C. Gen. Stat. § 62-350 requires that communications attachers and cooperatives must either negotiate for a period of 90 days or reach an impasse before submitting a pole attachment dispute to the Commission. *See* N.C. Gen. Stat. § 62-350(c). There are two ways to trigger this 90-day negotiation period under the statute: (1) "[f]ollowing receipt of a request from a communications service provider" or (2) "[f]ollowing a request from a party to an existing agreement," (that is, a request from either party), provided the request is "made pursuant to the terms of the agreement or made within 120 days prior to or following the end of the term of the agreement." *See* N.C. Gen. Stat. § 62-350(b).

Blue Ridge contends that the parties' negotiations in this case do not meet either of these triggers and that, as a result, the 90-day negotiating period never did commence. In support of this contention Blue Ridge observes that it sent a request to negotiate a renewed pole attachment agreement to Charter on May 22, 2014, which is more than 120 days from September 1, 2013—the date the 2008 Agreement was set to otherwise expire (*See* Layton Tr. Vol. 1, p. 36; see also Exhibit LL-3, p. 2) and that Blue Ridge is not a communications attacher. Thus, the negotiations were not initiated "following a request from a communications attacher," and the negotiations were not initiated "following a request …made [by either party] pursuant to the terms of the agreement or made within 120 days prior to or following the end of the term of the agreement." *See* N.C. Gen. Stat. § 62-350(b). Emphasis added. As a result, according to Blue Ridge, even if any new rate were to be applied retroactively, because the 90-day negotiating period never did commence, the new rate would apply only back to the commencement of this action, not the parties' negotiations.[1] The Commission does not agree.

N.C. Gen. Stat. § 62-350(c) expressly requires the Commission to award reimbursement of overpayments. The statute provides that any new rates set by the Commission "shall apply . . . retroactively to the date immediately following the expiration of the 90-day-negotiating period or initiation of the proceeding, whichever is earlier." N.C. Gen. Stat. § 62-350(c). Here, the 90-day negotiating period expired on August 25, 2015.[2] That date is well before the initiation date of this proceeding. Blue Ridge sent a proposed new agreement to Charter in May 2014. Charter responded to Blue Ridge's proposal on May 26, 2015, declaring at that time its intent to negotiate the agreement – including the rate – by submitting a redline of it.[3] Contrary to Blue Ridge's contention that Charter did not dispute the rate, Charter's redline flags Blue Ridge's rate and notes: "To be determined. These rates are to be calculated in accordance with the FCC cable formula."[4] Accordingly, Charter requested to negotiate the rate at that time – consistent with the requirements of N.C. Gen. Stat. § 62-350(b) – and the negotiating period expired 90 days later.

The Commission finds and concludes that the negotiating period commenced on May 26, 2015 and that the new rates determined in this case, therefore, will be effective as of August 25, 2015 (90 days after the start of the negotiating period). Based on the Commission's conclusion that Blue Ridge's maximum just and reasonable rates for the years 2015-2017 are properly calculated according to the FCC Rate Methodology, as modified to reflect the actual data supplied by witness Arnett, the Commission determines that, according to the evidence of record, Blue Ridge owes a refund to Charter for the period from August 25, 2015, through August 31, 2017[5] and that Charter shall calculate such refund and provide it to Blue Ridge for verification. Blue Ridge also owes a refund to Charter for any additional overpayments made to it based on Blue Ridge's excessive rate. The refunds shall be calculated based on the following guidelines.

In the past, Charter invoiced Blue Ridge on per attachment rather than a per pole basis. The 2015-2016 Inventory revealed that Charter had more attachments than there would have been if

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[1] According to Blue Ridge the pertinent provision of N.C. Gen. Stat. § 62-350(c) states: "The Commission shall apply any new rate adopted as a result of the action retroactively to the date immediately following the expiration of the 90-day negotiation period or the initiation of the proceeding, whichever is earlier."

[2] Although the parties' 2008 Agreement expired on September 1, 2013, and it is arguable that the negotiations under N.C. Gen. Stat. § 62-350 started on May 22, 2014, Charter seeks refunds of overpayments only from August 26, 2015, 90 days following its return of a redlined draft agreement to Blue Ridge.

[3] Mullins, Tr. Vol. 3, p. 236-37; *see also* Layton Ex. 7.

[4] *See* Layton Ex. 7, Draft Redline Agreement, Ex. C.

[5] The Commission notes that Blue Ridge's annual RUS filing shows accumulated Patronage Capital *****BEGIN CONFIDENTIAL*** ***END CONFIDENTIAL***** The record does not reflect whether some of the *****BEGIN CONFIDENTIAL*** **END CONFIDENTIAL***** Patronage Capital is the result of Blue Ridge accruing for this payment, but there is no testimony that payment by Blue Ridge of the refund will have any significant adverse effect on Blue Ridge or its members. [*See* Kravtin, Confidential Tr. Vol. 4, pp. 181-82 n.22.]

there was only one attachment per pole. Because of this mismatch between the number of poles and the number of attachments, witness Arnett determined that Charter occupied 1.11 feet of space per attachment rather than the one foot per attachment that the FCC and the TVA rate formulas presumed. Witness Arnett used this hybrid space allocation factor to calculate the maximum rate that Charter should have been paying under the TVA and the FCC rate methodologies. This hybrid rate thus accounts for the fact that Charter has more than one attachment on some poles.[1]

Charter does not object if Blue Ridge is permitted to charge Charter the FCC rate for any attachment that is not within one foot of another attachment. Charter contends, however, that it would be inappropriate for the Commission to allow Blue Ridge to charge per attachment and to also use an average occupancy of more than one foot because that would amount to double billing. The Commission agrees.

Thus, to be fair to Charter, any refund due Charter shall be determined by multiplying the rates calculated by witness Arnett times the number of poles in Blue Ridge's inventory for each year in question and subtracting that amount from the total amount of attachment fees that Charter paid for that year(s). The parties shall work collaboratively to calculate the refund due recognizing that, in the past, Charter has been billed on a per attachment basis and that the Commission is requiring the pole attachment rates determined in this proceeding to be hereinafter applied on a per pole basis.[2] If Blue Ridge desires, and Charter is agreeable, the Commission will allow the parties to use this refund amount as a credit against future pole attachment bills until the amount of the credit is fully exhausted.[3]

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 33

The evidence supporting this Finding of Fact is found in the testimony of witnesses Kravtin, Martin, Layton, Arnett and Booth.

Charter's witnesses agreed that under appropriate terms and conditions of attachment, and in addition to an annual pole attachment rental rate, Charter is responsible for paying any out-of-pocket expenses incurred by Blue Ridge directly attributable to Charter's attachments. Those expenses include the costs of making poles ready for Charter's attachments (including all costs associated with installing a new pole and removing the old pole, if necessary, to accommodate Charter's attachment); the costs incurred by Blue Ridge in conducting pre-construction inspections and engineering; the costs incurred in any post-construction inspection; measurable and direct

[1] Witness Arnett accepted the presumption that Charter's attachments use one foot of usable space. He nevertheless calculated that Charter should be treated as occupying 1.11 feet on average based on the audit results showing that Charter made 27,674 attachments on 24,888 poles.

[2] While the Commission has established that bills will be issued on this basis in the future, nothing precludes the parties from agreeing to a different arrangement.

[3] Blue Ridge witness Arnett testified that Charter is attached to 442 poles that are used for transmission (as opposed to distribution) of electricity. He testified that these poles are typically larger and more expensive than distribution poles and that it would be appropriate for Blue Ridge to charge a different rate for attachment to these poles than Blue Ridge charges for distribution poles. [Arnett, Tr. Vol. 2, p. 67.] Blue Ridge did not propose any rate for transmission poles in this proceeding, however, and under N.C. Gen. Stat. § 62-350, no such issue is before the Commission for resolution.

costs incurred by Blue Ridge in processing Charter's pole attachment applications; and the costs incurred by Blue Ridge in auditing those poles to which Charter is attached. [Kravtin, Tr. Vol. 4, pp. 184-85; Martin, Tr. Vol. 4, pp. 86-87.] Witness Kravtin termed these costs "but for" costs, and she testified that because Charter pays those costs, Blue Ridge's remaining marginal costs of attachment are very small, certainly well under the FCC fully allocated rate she advocates. [Kravtin, Tr. Vol. 4, pp. 176-77.]

Witnesses Arnett, Booth and Layton testified that Blue Ridge incurs additional costs related to providing pole attachments that should be recovered. [Arnett, Tr. Vol. 2, pp. 88-89; Booth, Tr. Vol. 3, pp. 58-59, 72;. Layton, Tr. Vol. 1, pp. 55-57.] These witnesses testified that Charter's presence on Blue Ridge's poles creates numerous costs and burdens on the EMC that would not be present "but for" Charter's attachments. [Booth, Tr. Vol. 3, pp. 58-59, 72; Arnett, Tr. Vol. 2, pp. 88-89.] According to this testimony, these costs and burdens include pole damage, pole climbing impediments, impediments to vegetation management, clearance violations, public safety violations, failure to allow for expansion by Blue Ridge, failure to bond equipment to pole ground, downed Charter cables, and various administrative costs. [Booth, Tr. Vol. 3, pp. 78-81, 85-93.] Witness Arnett testified that the annual rental rate does not cover all "but for" costs and argued that Blue Ridge should be allowed to charge Charter separately for the hiring of administrative personnel to oversee Charter's attachments. [Arnett, Tr. Vol. 2, pp. 88-89.] No witness on behalf of Blue Ridge presented evidence of any specific amounts that it contended Charter should be charged for additional "but for" costs.

Witness Kravtin, in response to the testimony of witnesses Booth and Arnett, said that undocumented "but for" costs could not properly be added to the fully allocated costs allowed under the FCC Rate Methodology. [Kravtin, Tr. Vol. 4, p. 201.] She noted that not only does the fully allocated FCC Rate provide additional contribution to the pole owner beyond "but for" costs, [Kravtin, Tr. Vol. 4, p. 170], but also that similarly undocumented claims of "but for" costs of pole owners have been rejected by the FCC.[1]

Discussion and Conclusions

The Commission concludes that, in addition to an annual pole attachment rate, it is appropriate for Charter to pay the direct and measurable out-of-pocket "but for" costs for certain expenses incurred by Blue Ridge associated with Charter's attachments, including make-ready construction and engineering costs and the costs to Blue Ridge of post-construction inspections and audits of poles to which Charter is attached.

Blue Ridge argues that Charter is responsible for other "but for" costs that should be the direct responsibility of Charter. The testimony is unclear, however, as to what conditions Blue Ridge has identified regarding Charter's facilities have been caused by Charter, as opposed to other parties. Equally importantly, Blue Ridge has not introduced any evidence of the amount of any of the "but for" costs Blue Ridge claims. Without any evidence of the amount of additional costs it

[1] The FCC rejected similar claims by electric utilities that were submitted without any cost study. *See* Implementation of Section 224 of the Act, Report & Order on Reconsideration, 26 FCC Rcd 5240 ¶¶ 189-190 (2011), aff'd sub nom. Am. Elec. Power Serv. Corp. v. FCC, 708 F.3d 183 (D.C. Cir. 2013) (rejecting pole-owner claims that they incur significant unrecovered costs outside of the make-ready process because they "did not provide any cost study" demonstrating additional costs incurred "solely to accommodate third party attachers").

claims, or even how to calculate them, the Commission has no basis in the record heretofore developed to award them, even were it otherwise inclined to do so. Nor is the Commission willing to simply allow Blue Ridge to impose on Charter generalized, non-specific and non-verifiable costs, in addition to verifiable out-of-pocket costs that Charter has testified are appropriate and the fully allocated costs recovered in the annual FCC Rate. Not only would such a practice undoubtedly cause additional conflict and the potential for additional and unnecessary proceedings before the Commission, but this Commission has previously, and correctly, rejected efforts to set rates by reference to undocumented costs. *See, e.g.*, Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 106, at 23-24 (Dec. 19, 2007) ("uncertain and unquantifiable costs . . . should not be taken into account in calculating avoided cost rates").

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 34

The evidence supporting this Finding of Fact is found in the testimony of witnesses Martin, Mullins, Kravtin, Layton, Arnett and Booth.

Blue Ridge has raised a number of issues related to the terms and conditions of attachment to be contained in a new pole attachment agreement between the parties.

Through witness Kravtin, Charter presented testimony that Blue Ridge has been able to exercise leverage over Charter because it has "monopoly ownership and control over the existing distribution network of poles." [Kravtin, Tr. Vol. 4, p. 168.] According to witnesses Kravtin, Mullins and Martin, Charter has no practical alternative to attaching to Blue Ridge's poles in its service territory. [Kravtin, Tr. Vol. 4, pp. 174-75; Martin, Tr. Vol. 4, p. 79; Mullins, Tr. Vol. 3, p. 227.] Regardless of the size of the entities, witness Martin testified, the pole owner has a monopoly on critical infrastructure and has the "ability to dictate the terms of attachment." [Martin, Tr. Vol. 4, p. 79.] Witness Arnett testified that there are some places where other pole owners have poles that would serve as an alternative for Charter. [Arnett, Tr. Vol. 2, p. 87.] But witness Arnett was not able to estimate how prevalent such situations are in the field. [Arnett, Tr. Vol. 3, pp. 16-17.]

Witness Martin introduced evidence of industry standard terms of attachment that are present in most pole attachment agreements, even in the absence of any regulatory oversight. Witness Martin testified that Charter's attachments are generally the same regardless of the pole owner and that most pole agreements are similar. [Martin, Tr. Vol. 4, p. 77.] Because most agreements are similar, witness Martin testified, "they can serve as a barometer of what terms and conditions are just and reasonable." [Martin Tr. Vol. 4, p. 78.]

Witness Martin also testified that there are standard terms and conditions that other pole owners, including cooperatives in North Carolina, accepted both before and after the advent of regulatory oversight, and that these terms continue in effect. [Martin, Tr. Vol. 4, p. 78, and NM Ex. 3.] According to witness Martin, these agreements help to establish the industry standard terms on which Charter relies. [Martin, Tr. Vol. 4, pp. 78, 83-84, and NM Ex. 3.]

Witness Booth testified as an engineering expert for Blue Ridge in this proceeding. He is a professional engineer who has an extensive history of assisting cooperative utilities, including

Blue Ridge, for more than 50 years in engineering matters. [Booth, Tr. Vol. 3, pp. 54-57.] He has served as an expert witness for cooperatives in litigation matters in a large number of cases, and he assisted Jones-Onslow Electric Membership Corp., in developing its agreement with Time Warner Cable Southeast LLC, as reflected in the January 2018 Pole Attachment Orders. *See* GLB Ex. 1; see also Order Resolving Pole Attachment Complaint Pursuant to G.S. 62-350, Docket No. EC-43, Sub 88 (JOEMC), at *51 (NCUC Jan. 9, 2018). He also served as a rate expert for Rutherford EMC in the Rutherford case before the Business Court.

In this proceeding, witness Booth urged the Commission to adopt language for Blue Ridge's pole attachment agreement different from and far more restrictive than the language in the 2007 JOEMC agreement on which witness Booth had advised the EMC. *See* Order Resolving Pole Attachment Complaint Pursuant to G.S. 62-350, Docket No. EC-43, Sub 88 (JOEMC), at *51 (NCUC Jan. 9, 2018). In his testimony in the instant matter, witness Booth relied on the many photographs of Charter's facilities that were contained in his exhibits. [Booth Tr. Vol. 3, pp. 75 and Ex. GLB 3.] He testified that the photographs show safety hazards, pole damage and other problems caused by Charter. [Booth, Tr. Vol. 3, pp. 78-81.] In light of what witness Booth contended are unsafe and unsound practices on the part of Charter, he asserted that Blue Ridge requires language in the agreement that better protects it. [Booth, Tr. Vol. 3, pp. 60-65.] Neither witness Booth nor any other witness for Blue Ridge addressed Charter's extensive testimony about the industry standard terms that are found across pole attachment agreements in North Carolina.

Discussion and Conclusions

The Commission is mindful that many of the issues related to the contractual terms and conditions raised in this case have been addressed by the FCC and other regulatory authorities. In addition, extensive evidence has been presented of certain "industry standard" terms and conditions that have been accepted by North Carolina cooperatives prior to this Commission being afforded jurisdiction over these matters. Where there are templates for resolution of similar concerns that have been accepted by a regulatory authority that has dealt with pole attachments for decades, and where large numbers of electric cooperatives have accepted terms and conditions as safe and protective of the reliability of their networks when there was no regulatory oversight, the Commission will look closely to those sources as potentially reflecting an unbiased resolution of the issues presented by the parties in this case.

The evidence reflects that the terms and conditions of attachment to EMC poles were largely within the control of the EMCs prior to regulation under N.C. Gen. Stat. § 62-350. No tribunal had jurisdiction over EMCs' pole attachment service until 2009. Yet Charter had a need to attach, and especially to retain its existing attachments, to Blue Ridge's poles.

In this Order, the Commission will address individually each of the issues related to terms and conditions of agreement that are listed in the parties' November 2, 2017 Joint Statement of Issues. In this case, Blue Ridge argues that a number of the terms and conditions specified in its 2008 pole attachment agreement with Charter are just and reasonable, while Charter argues that they are burdensome, unreasonable and contrary to industry standard. The Commission notes that whereas voluntary agreement by Blue Ridge and Charter to terms and conditions that Charter also found acceptable in the past was evidence of the reasonableness of those terms and conditions, the fact that Charter and Blue Ridge agreed to certain provisions that Charter now contests is less persuasive evidence of reasonableness because at the time the 2008 Agreement was executed, Charter had limited leverage and there was no tribunal with authority to protect Charter's rights to reasonable terms. [Kravtin, Tr. Vol. 4, pp. 180-81; Martin, Tr. Vol. 4, pp. 78-80; Mullins, Tr. Vol. 3, p. 223.]

The Commission will now address and provide a decision individually on each of the contested terms and conditions (Issues (a) through (l) – or referred to as Issue Nos. 3(a) through 3(l) per the November 2, 2017 Joint Statement of Issues).

Issue (a): Disputed Invoices[1]

Witnesses Layton and Booth, on behalf of Blue Ridge, argued that Charter should be required to pay any disputed invoices, and that allowing Charter to withhold payment on disputed invoices until the dispute is resolved creates an incentive for Charter to unreasonably dispute payment obligations. [Layton, Tr. Vol. 1, pp. 60-61; Booth, Tr. Vol. 3, p. 63.] Witness Layton also testified that Charter had recently refused to pay for two make-ready projects, despite the fact that the parties do not dispute the amount owed. [Layton, Tr. Vol. 1, pp. 60-61.]

On behalf of Charter, witness Martin testified that if Charter were required to pay where there is a good faith dispute, Blue Ridge would have an incentive to work less efficiently to resolve the dispute. Witness Martin also noted that N.C. Gen. Stat. § 62-350(c) addresses the issue, requiring that a party pay undisputed amounts prior to bringing an issue to the Commission. [Martin, Tr. Vol. 4, p. 108.]

Discussion and Conclusions for Issue (a)
Disputed Invoices

Sections 4.2 of the parties' 2003 and 2008 Agreements respectively require Charter to pay Blue Ridge's monthly invoices for attachment fees within 30 days. Those same provisions, however, recognize that Charter may not pay invoices within the 30 day period and provide that, when that occurs, interest shall accrue on the unpaid attachment fees and charges at twelve percent (12%) per annum.[2] In negotiating a new Agreement, Charter has insisted on including provisions in any new agreement that would allow it to withhold payment on any disputed invoices until the dispute is resolved. While Blue Ridge agrees that it is appropriate for Charter to have a mechanism to dispute invoices, Blue Ridge argues that Charter should be required to pay outstanding invoices in full pending resolution of the dispute. See Blue Ridge Proposed Order, p. 50. Charter objects to this proposal.

In 2009, the General Assembly enacted N.C. Gen. Stat. § 62-350. In pertinent part, N.C. Gen. Stat. § 62-350(c) provides that "[p]rior to initiating any proceeding under this subsection, a party must pay any undisputed fees related to the use of poles, ducts, conduits which are due and owing under a preexisting agreement with the [] membership corporation. In any proceeding brought under this subsection, the Commission may resolve any dispute regarding fees alleged to

[1] Issue No. 3(a) per the November 2, 2017 Joint Statement of Issues.

[2] The 2003 Agreement and the 2008 Agreement are essentially identical. See Blue Ridge Answer to Counterclaim.

be owing under a preexisting agreement or regarding safety compliance arising under subsection (d) of this section." This provision clearly contemplates that: (1) there will be fee disputes between attachers and pole owners; (2) the Commission will be asked to resolve these disputes; and (3) prior to bringing any of these disputes to the Commission for resolution, a party must pay all undisputed amounts to the opposing party. This provision clearly does not contemplate that a party must pay all disputed invoices to the opposing party prior to bringing a dispute to the Commission for resolution.

Blue Ridge's argument that Charter should be required to pay any disputed invoices in full pending resolution of the parties' disagreement by this Commission is inconsistent with the tone, tenor and text of N.C. Gen. Stat. § 62-350. It is also inconsistent with the tone, tenor and text of the 2003 and 2008 Agreements, which Charter had little choice but to accept if it wished to provide service in the areas served by Blue Ridge. Therefore, the Commission denies Blue Ridge's request that Charter be required to pay in full any invoices which it disputes in good faith prior to filing a fee dispute resolution proceeding with this Commission and affirms that, under N.C. Gen. Stat. § 62-350, Charter is only obligated pay any undisputed invoices to Blue Ridge prior to filing a dispute resolution proceeding with the Commission. The Commission will, however, expect the parties to behave in good faith toward each other in regards to paying and/or disputing invoices.

Issue (b): Requirements regarding new attachments, overlashing and drop poles (a/k/a secondary poles)[1]

Witness Layton, on behalf of Blue Ridge, testified that, in its negotiations, Charter took the position that it should be required to seek a permit only for projects involving ten or more attachments. Instead, witness Layton requests the Commission to require that Charter apply for a permit for each attachment and pay an associated application fee. [Layton, Tr. Vol. 1, p. 60.]

Witness Booth testified on behalf of Blue Ridge that various safety violations by Charter caused damage to Blue Ridge. Witness Booth maintained that Charter should not be allowed to overlash its facilities without completing a full application process to ensure that Blue Ridge has notice and an opportunity to review and approve the design and construction. [Booth, Tr. Vol. 3, p. 61.] He testified that overlashing can affect the windloading on a pole and that this should be "policed through the permitting process."[2] [Booth, Tr. Vol. 3, pp. 61, 97.] No witness for Blue Ridge presented any testimony on why aerial drops not physically attached to the pole should be considered an attachment.

Charter witness Martin proposed the following language for Blue Ridge's and Charter's pole attachment agreement related to the permitting process:

> ***Permit and Approval Process:*** *Charter shall comply with the Cooperative's generally applicable, non-discriminatory Attachment approval application procedures for all new Attachments to the Cooperative's poles, except for secondary poles (a/k/a lift poles or drop poles). Charter shall notify Cooperative of all new secondary pole Attachments on a quarterly basis, and such Attachments*

[1] Issue No. 3(b) per the November 2, 2017 Joint Statement of Issues.

[2] ***BEGIN CONFIDENTIAL*** ***END CONFIDENTIAL***

shall be subject to the Annual Attachment Fee. Charter may overlash its existing Attachments where such activity will not cause the Attachment to become noncompliant with the safety standards described above. Charter shall provide prior notice to Cooperative of all new overlashings at least 15 days in advance, except for projects involving the overlashings of 5 or fewer poles, when Charter shall provide at least forty-eight (48) hours prior notice to Cooperative. Licensor may perform a post-overlash inspection of Licensee's overlashing on poles as Licensor deems critical in its reasonable discretion, including reliance on Licensor's professional engineers as Licensor deems necessary, and Licensee shall pay for the actual cost. Licensee shall provide sufficient information regarding its overlash to allow Licensor to determine the impact of Charter's overlash on the pole loading. There shall be no additional annual Attachment Fee for overlashings of Licensee's existing facilities. [Martin, Tr. Vol. 4, pp. 94-95.]

The testimony of the parties was consistent that Charter should be required to file an application and obtain a permit before attaching to a mainline distribution pole. [*See, e.g.*, Martin, Tr. Vol. 4, pp. 94-95; Layton, Tr. Vol. 1, p. 60.]

Witnesses Martin and Mullins testified that it is impractical to both provide timely service and treat drop poles as attachments subject to the same notice or permitting to which mainline poles are subject.[1] [Martin, Tr. Vol. 4, pp. 118-19; Mullins, Tr. Vol. 3, pp. 233-34.] Witness Martin agreed that after-the-fact notice of drop attachments is, however, appropriate, and his exhibit showed that it is industry-standard. [Martin, Tr. Vol. 4, p. 94-95; NM Ex. 3.]

Witness Martin testified that "overlashing" a light-weight, half-inch in diameter cable onto an existing steel strand hung between poles is an important technique for efficiently and cost-effectively deploying advanced communications services. [Martin, Tr. Vol. 4, pp. 93-94.][2] A reasonable contractual term, he stated, will allow overlashing by Charter upon prior notice that includes information necessary for Blue Ridge to conduct a safety analysis of the overlash. [Martin, Tr. Vol. 4, p. 90-91.] Witness Martin also testified that this practice has provided a practical solution acceptable to other cooperatives in the past. [Martin, Tr. Vol. 4, p. 91.]

Witness Martin testified that it is industry-standard in pole attachment agreements to allow overlashing of existing attachments without additional permitting or even notice. He stated that in his review of 90 pole attachment agreements with various North Carolina pole owners, 72% of those agreements do not require any notice or permitting for overlashing. [*See* NM Ex. 3, pp. 12-23.] Of the remaining 25 agreements, 19 require notice only after the fact. [*See* NM Ex. 3, pp. 12-23.] Only 6 agreements require permitting prior to overlashing being performed. [*See* NM Ex. 3, pp. 12-23.] Witnesses Martin and Mullins observed that Charter is one of the only attachers required to submit a permit to Blue Ridge prior to overlashing, even though overlashing by third-parties is common and Charter's direct competitors are not subject to the same permitting

[1] Drop poles, also referred to as Secondary Poles or Lift Poles, are typically installed across a street from the main distribution pole line in order to provide clearance for facilities necessary to provide service to a customer.

[2] Overlashing is the process of lashing additional fiber or coaxial cable onto an existing steel strand hung between poles.

requirements.[1] [Mullins, Tr. Vol. 3, pp. 225, 241-42; Martin, Tr. Vol. 4, p. 92; *see* MM Ex. 1.] Witness Martin also testified that his proposed language is consistent with the FCC's determination that attempts to impose permitting requirements for overlashing are "unjust and unreasonable on [their] face." [Martin, Tr. Vol. 4, 92-93.]

Discussion and Conclusions for Issue (b)
Requirements regarding new attachments, overlashing, and drop poles (a/k/a secondary poles)

The parties agree that Charter is (and should be) required to submit an application and obtain approval from Blue Ridge prior to making an attachment on a mainline distribution pole. No evidence was submitted of any specific safety issues that would require prior approval or application for attachment to drop poles, and the record reflects a strong industry standard of allowing Charter to continue to provide notice of drop attachments after-the-fact. The FCC requires Charter to provide service to new customers within seven days, which would not be possible if a full permitting process for drop poles were required. 47 C.F.R. § 76.309(c)(2)(i). Blue Ridge does not require any kind of notice of overlashing by joint user telephone companies, who often overlash bigger and heavier cables to their strand. [Martin, Tr. Vol. 4, pp. 93-94; *see* Mullins, Tr. Vol. 3, pp. 239-40.]

Witness Martin's proposed language regarding overlashing would require Charter to supply sufficient information to allow Blue Ridge to determine the impact of the overlashing on pole loading, and would permit Blue Ridge to conduct a post-overlash inspection (by a registered professional engineer if deemed necessary) at Charter's cost. Under these notice requirements proposed by Charter, Blue Ridge would receive 30 days' prior notice for overlashing projects involving 20 or more poles, 15 days' notice for six to 19 poles and 48 hours' notice for projects of five or fewer poles. Charter's additional proposed language would address witness Booth's concerns about pole loading by requiring Charter to supply information that will allow Blue Ridge to determine the effect on loading at Charter's expense. Accordingly, the Commission finds it appropriate to approve the following language as proposed by Charter:

> ***Permit and Approval Process:*** *Charter shall comply with Cooperative's Attachment approval application procedures for all new Attachments to the Cooperative's poles, except for secondary poles (a/k/a lift poles or drop poles). Charter shall notify the Cooperative of all new secondary pole Attachments on a quarterly basis, and such Attachments shall be subject to the Annual Attachment Fee. Charter may overlash its existing Attachments where such activity will not cause the Attachment to become noncompliant with the safety standards described above. Charter shall provide prior notice to the Cooperative of all new overlashings at least 30 days in advance for projects involving overlashing to 20 or more poles, at least 15 days in advance for projects involving overlashing 6 to 19 poles and at least 48 hours in advance for projects involving overlashing 5 or fewer poles. The Cooperative may perform a post-overlash inspection of Charter's overlashing on poles as the Cooperative deems critical in its reasonable discretion, including reliance on the Cooperative's professional engineers as the Cooperative*

[1] *See also* *** BEGIN CONFIDENTIAL*** *** END CONFIDENTIAL***

deems necessary, and Charter shall pay for the actual cost. Charter shall provide sufficient information regarding its overlash to allow the Cooperative to determine the impact of Charter's overlash on the pole loading. There shall be no additional annual Attachment Fee for overlashings of Charter's existing facilities.

<u>Issue (c): Certification requirements related to Charter's attachments to Blue Ridge's poles</u>[1]

Witness Booth testified that neither Charter nor its contractors carefully review whether they are meeting NESC requirements [Booth, Tr. Vol 3, p. 82], adding that contractors used by communications attachers generally, including ILECs and other phone companies, are not properly trained in Code requirements. [Booth, Tr. Vol. 3, p. 160.] He believes that the lack of training applies to the "entire communications industry across the board." [Booth, Tr. Vol. 3, p. 160.] He also testified that Charter and its contractors do not engage the services of professional engineers (PEs). [Booth, Tr. Vol. 3, pp. 58-59.] Witnesses Layton and Booth also testified that a North Carolina statute, N.C. Gen. Stat. § 89C-2, requires that a person be certified as a professional engineer to certify compliance with the NESC. [Layton, Tr. Vol. 1, p. 61; Booth, Tr. Vol. 3, p. 95.] Witness Booth proposed that the pole attachment agreement require Charter within 30 days of installing the last attachment or overlashing covered by a permit provide Blue Ridge a certification by a professional engineer, licensed and registered in North Carolina, that the attachments "are of sound engineering design and fully comply with the safety and operational requirements of the agreement, including without limitation the NESC." [Booth, Tr. Vol. 3, p. 95.] If the certification is not provided, witness Booth requests that Blue Ridge have the right to declare that the attachment is unauthorized. [Booth, Tr. Vol. 3, p. 95.]

Witness Martin proposed the following language on behalf of Charter:

<u>Certification</u>: *Upon written request from the Cooperative, no later than 30 days after Charter installs the last Attachment covered by its approved application, Charter shall send to the Cooperative a certification (the "Certification") by a Registered Professional Engineer in the State of North Carolina or an authorized representative that the Attachments are of sound engineering design and fully comply with the safety and operational requirements of this Agreement, including without limitation the National Electrical Safety Code. If Certification is not received when requested, the Cooperative may declare the Attachment to be unauthorized.* [Martin, Tr. Vol. 4, pp. 90-91.]

Witness Martin testified that Charter does not rely on professional engineers and expressed his view that it is unnecessary to obtain routine certification for every installation. Instead, his exhibit showed that the industry standard, to the extent pole agreements address certification at all, is for a certification by an "authorized representative" of the attacher with knowledge and experience with the NESC and safety and operational requirements.

Witness Martin also testified that requiring a professional engineer to certify each communications attachment is unnecessary and would be prohibitively expensive. [Martin, Tr. Vol. 4, p. 89.] Charter competes directly with ILECs such as Skybest, CenturyLink, and AT&T

[1] Issue No. 3(c) per the November 2, 2017 Joint Statement of Issues.

in Blue Ridge's territory in the provision of video, internet, and voice services. [*See* Martin, Tr. Vol. 4, pp. 83, 94; Mullins, Tr. Vol. 3, p. 223.] Charter's competitors attach facilities much like Charter's to Blue Ridge's poles. [*See* Martin, Tr. Vol. 4, p. 83; NM Ex. 3.] Blue Ridge's joint use agreements with Charter's competitors do not require any professional engineer [Martin, Tr. Vol. 4, p. 89.][1] Further, witness Booth testified that Blue Ridge itself does not perform a full PE analysis of each and every one of its own attachments. [Booth, Tr. Vol. 3, pp. 83-84.] Witness Martin testified that if Blue Ridge believes that a professional engineer is required in any instance, it can have a professional engineer conduct a post-construction inspection at Charter's expense. [Martin, Tr. Vol. 4, p. 89.] Charter's proposed language contains such a provision. [Martin, Tr. Vol. 4, pp. 89-90.] Witness Mullins testified that Charter has an arrangement with Duke Energy under which Duke contracts with a third-party engineering group that reviews Charter's attachments at Charter's expense. [Mullins, Tr. Vol. 4. p. 53.]

Discussion and Conclusions for Issue (c)
Certification requirements related to Charter's attachments to Blue Ridge's poles

Section 5.9 of Charter's 2003 and 2008 Agreements with Blue Ridge both required Charter to provide, within 30 days after completing the last attachment covered by an application, a certification from a professional engineer that Charter's attachments to Blue Ridge's poles "are of sound engineering design, fully comply with the [Rules specified in the agreement], th[e] agreement and the latest edition of the National Electric Safety Code, and were constructed as provided in the Make Ready Engineering Plans" Charter provided in its application. The agreements required Charter to make this certification in a form attached to the agreements as an exhibit, which requires a professional engineer's signature.

Charter, despite having agreed to these provisions twice before without any request for modification, has refused to accept them in its current negotiations with Blue Ridge, and instead proposes that it (i) should be allowed to provide certification from an "authorized representative," and (ii) should not have to provide any certification with respect to secondary or "drop" poles that serve a single house.

Charter's proposal that it provide a certification from only "an authorized representative", which could be any employee, is inadequate to address Blue Ridge's safety concerns and assure it that Charter's attachments comply with the NESC and applicable safety standards. Moreover, it would be unlawful for one of Charter's employees to certify that Charter's attachments are of "sound engineering design and fully comply" with the NESC and other design specifications, unless he or she is a licensed engineer. *See* N.C. Gen. Stat. § § 89C-2 and 89C-3. At the hearing, witness Booth, himself a licensed professional engineer, introduced guidance he received from the North Carolina Board of Examiners for Engineers and Land Surveyors, advising that providing such a certification would require a professional engineer's license under N.C. Gen. Stat. § 89C-3(6), and that doing so without a license would violate N.C. Gen. Stat. § 89C-2.

Accordingly, the Commission concludes that Blue Ridge's proposed terms and conditions requiring Charter to provide a certification from a licensed professional engineer that its attachments are of sound engineering and comply with applicable design and safety standards, as

[1] *****BEGIN CONFIDENTIAL*** ***END CONFIDENTIAL*****

set forth in its 2003 and 2008 Agreements with Charter, are just and reasonable and appropriate for inclusion in a new pole attachment agreement between the parties. In doing so, however, the Commission further concludes that the language adopted herein does not specify that the professional engineer must be a Charter employee. The Commission therefore concludes that Charter may fulfill the requirements of this provision by contracting directly with a professional engineer or through some other third-party arrangement.

<u>**Issue (d): Transferring attachments**</u>[1]

Blue Ridge suggested that if Charter does not act on any Blue Ridge request that Charter transfer its facilities to a different pole in a timely fashion, Blue Ridge may consider the attachment unauthorized, assess an unauthorized attachment fee, and recover from Charter all costs associated with making a transfer without incurring liability to Charter.[2] [Booth, Tr. Vol. 3, pp. 99-100.]

Witness Martin testified that Charter accepts responsibility for the costs incurred by Blue Ridge for any failures to timely meet requests to transfer its facilities, and is prepared to reimburse Blue Ridge for the actual costs of performing work Blue Ridge undertakes that Charter is required to perform under the terms of the agreement. [Martin, Tr. Vol. 4, p. 105.] Noting that the Cooperative could revoke an attachment permit and deem an overdue transfer to be an Unauthorized Attachment or engage in self-help at Charter's expense if Charter's failure to complete the transfer becomes problematic, Charter proposed the following language:

> ***<u>Transfers & Relocation</u>****: The Cooperative may replace or relocate poles for a number of reasons, including without limitation when existing poles have deteriorated, when new attachers require additional pole space, and when poles must be relocated at the request of the North Carolina Department of Transportation, another governmental body or a private landowner. In such cases, Charter shall, within 60 days after receipt of written notice, transfer its Attachments to the new poles. If such transfer is not timely performed, the Cooperative may, at its option: (i) revoke the permit for the Attachment and declare it to be an Unauthorized Attachment subject to the Unauthorized Attachment fee; or (ii) transfer Charter's Attachments and Charter shall reimburse the Cooperative for the actual costs of completing such work. If Cooperative elects to do such work, it shall not be liable to Charter for any loss or damage except when caused by the Cooperative's gross negligence or willful misconduct.* [Martin, Tr. Vol. 4, pp. 105-06.]

Discussion and Conclusions for Issue (d)
Transferring attachments

Here, the parties appear to be in agreement on this issue. Witness Booth testified that "[a]s Charter's proposal is generally consistent with the 2008 Agreement, it appears to be reasonable." [Booth, Tr. Vol. 3, p. 139.] Charter's proposed provision guarantees the Cooperative will recover any costs incurred for completing the work and ensures all parties know the Unauthorized

[1] Issue No. 3(d) per the November 2, 2017 Joint Statement of Issues.

[2] ***BEGIN CONFIDENTIAL*** ***END CONFIDENTIAL***

Attachment fee upfront, which should be sufficient to incentivize compliance. Therefore, the Commission concludes that Charter's proposed language is appropriate.

Issue (e): Non-compliant attachments[1]

On behalf of Blue Ridge, witness Booth testified in favor of language in the pole agreement that would require Charter to provide a plan to correct non-compliant attachments within a time certain.[2] [Booth, Tr. Vol. 3, p. 135.] Witness Booth argued that allowing Charter to correct non-compliant attachments within a "reasonable timeframe" would invite litigation. [Booth, Tr. Vol. 3, p. 135.]

Witness Booth testified that the photographs included in his exhibits demonstrated a wide scope of Charter's non-compliant attachments. He proposed unspecified amounts of "liquidated damages" for any non-compliant Charter attachment. [Booth, Tr. Vol. 3, pp. 60-61.] Witness Mullins on behalf of Charter testified that Charter had not had an opportunity to fully review the situations presented by the photographs in witness Booth's hearing exhibits, but that he believed that much of the noncompliance depicted was created by Blue Ridge and other attachers. [Mullins, Tr. Vol. 3, pp. 267-77.] There is also widespread agreement that attachments that are at one time compliant may fall out of compliance due to natural forces, and that all attaching parties' attachments, including Blue Ridge's, may fall out of compliance and require maintenance and correction. [Martin, Tr. Vol. 4, p. 97; Mullins, Tr. Vol. 3, pp. 259-60.]

Witness Martin proposed the following language for the Blue Ridge pole agreement:

> ***Notification and Opportunity to Cure Safety Violations:*** *If Charter's Attachments are out of compliance with applicable safety and operational requirements and specifications, whether in a safety inspection or otherwise, then the Cooperative will provide written notice to Charter of the non-compliant Attachment containing the pole number, location, and description of the problem. Charter must either contest the notice of non-compliance in writing or correct them consistent with the specifications of G.S. 62-350(d)(1). If Charter should fail to correct the non-compliance within a reasonable timeframe within G.S. 62-350, the Cooperative may revoke the permit for the Attachment. The cost of correcting all violations shall be borne by the party that has created the violation. Charter shall not be responsible for the cost of correcting a non-compliant Attachment(s) that were placed by or otherwise created by Cooperative or another attacher after Charter's facilities were attached.* [Martin, Tr. Vol. 4, p. 98.]

As witness Martin explained, the NESC does not require that existing facilities be brought up to the latest version of the Code, except where specifically indicated. [Martin, Tr. Vol. 4, pp. 99-100.] Witness Martin proposed the following language to clarify this issue:

> ***Compliance with Safety Standards:*** *Charter's Attachments constructed on the Cooperative's poles after the Commencement Date shall be placed and maintained*

[1] Issue No. 3(e) per the November 2, 2017 Joint Statement of Issues.

[2] *****BEGIN CONFIDENTIAL*** ***END CONFIDENTIAL*****

at all times in accordance with the requirements and specifications of the National Electrical Safety Code, the National Electrical Code, the North Carolina Department of Transportation, the Occupational Safety and Health Act, the Rural Utilities Service, the Society of Cable Television Engineer's Recommended Practices for Coaxial Cable Construction and Testing and for Optical Fiber Cable Construction, and the operational standards developed by the Cooperative. And in all cases as such requirements, specifications, and standards may be modified, revised, supplemented or replaced from time to time, all revisions taking effect after Charter's facilities have been installed shall be treated as applying on a prospective basis, except to the extent NESC requires that a modified, revised, supplemented or replaced rule must be applied retroactively. [Martin, Tr. Vol. 4, p. 100.]

Discussion and Conclusions for Issue (e)
Non-compliant attachments

The Commission has insufficient basis, at this time, to determine causation and responsibility for any compliance issues reflected in witnesses Booth's or Layton's photographs. Furthermore, N.C. Gen. Stat. § 62-350 sets forth required processes and procedures for dealing with non-compliant attachments. The statute does not provide for penalties for non-compliant attachments, and the Commission has no basis for accepting any "liquidated damages" amounts. *See* Eastern Carolina Internal Medicine P.A. v. Faidas, 149 N.C. App. 940, 945-46 (N.C. Ct. App. 2002).[1]

Under Charter's proposed language, all attachments, post-agreement, would have to comply with the most current safety standards that are in place on the date that the attachment is placed. Thus, the practical effect of the language proposed by Charter is to grandfather or protect all authorized attachments which were placed on Blue Ridge's poles prior to the commencement of any new agreement from revision or modification that might be necessitated by future changes by the organizations specified above (including Blue Ridge) unless the revision or modification is mandated by the NESC. The Commission finds unpersuasive witness Booth's contention that allowing Charter to correct non-compliant attachments within a "reasonable time" invites disputes. The Commission recognizes that fixing some compliance issues often requires the cooperation and coordination of two or more parties on a pole. Furthermore, provisions that allow Blue Ridge to recover any costs incurred for completing work and clear Unauthorized Attachment fees will incentivize compliance.

The Commission, therefore, finds it appropriate to adopt Charter's proposed language.

[1] In Eastern Carolina Internal Medicine, the court found that liquidated damages are permitted when they are reasonable estimates of probable damages or where they are reasonably proportionate to the actual damage caused by a breach. But penalty clauses designed as punishment or a threat to prevent a breach are not enforceable. 149 N.C. App. at 945-56.

Issue (f): Insurance requirements[1]

Witness Layton testified that, to adequately protect Blue Ridge, Charter should be required to carry sufficient insurance to meet requirements imposed by the RUS, Blue Ridge's lender. [Booth, Tr. Vol. 3, 141.] On behalf of Charter, witness Martin testified that the amount of insurance it carries should be consistent with the standards set by Charter's management, and that the requirements of RUS for financing Blue Ridge's infrastructure do not apply to Charter. [Martin, Tr. Vol. 4, p. 109.]

Discussion and Conclusions for Issue (f)
Insurance Requirements

In its Post Hearing Brief and Proposed Order, Blue Ridge states that the RUS, the government agency that provides loans to finance construction of Blue Ridge's system, "mandates" that all of its borrowers require third parties working on their system to provide proof of such insurance and to maintain the levels of insurance set forth in its proposed terms and conditions. In support of this proposition, Blue Ridge cited 7 C.F.R. § 1788.48. However, 7 C.F.R. § 1788.48 applies only to "contractors, engineers, and architects performing work for borrowers under construction, engineering and architectural service contracts..." 7 C.F.R. § 1788.47(a). Charter is not a contractor, engineer, and/or architect performing work for Blue Ridge. Thus, 7 C.F.R. § 1788.48 does not support Blue Ridge's request that Charter be required to maintain coverages for worker's compensation, commercial general liability and automobile liability insurance sufficient to meet requirements imposed by RUS. As a result, the Commission determines that Blue Ridge has not met its burden to establish a basis for its complaint on this subject and that its request that the Commission conclude that Blue Ridge's proposed terms and conditions requiring Charter to maintain specified levels of insurance, as set forth in Article 20 of the 2003 and 2008 Agreements is just reasonable and appropriate for inclusion in a new pole attachment agreement between the parties should be and is hereby denied.

In making this determination, the Commission notes that Charter indicated that "[it] is willing to maintain sufficient coverages for worker's compensation, commercial general liability, and automobile liability insurance, as determined by Charter's risk management." Martin, Tr. Vol. 4, p. 109. However, Charter has not filed any proposed language that details the kinds, amounts and the terms of the coverage that its risk management has determined would be sufficient to adequately insure the risks that arise in this situation. And, the record is, for the most part, devoid of any substantive discussion regarding this proposal. In the absence of such, the Commission cannot determine from the record here presented whether Charter's proposal is just and reasonable, whether it would alleviate the concerns expressed by Blue Ridge that Charter's position amounts to no commitment at all, as it would allow Charter to drop or increase its coverage at any time, and/or whether Blue Ridge would be amenable to Charter's proposal if its concerns could somewhat be alleviated after further discussions and negotiations. In light of this, the Commission finds and concludes that further discussions and negotiations about this issue are warranted. The Commission therefore directs the parties to re-start good faith negotiations with the goal of resolving this issue.

[1] Issue No. 3(f) per the November 2, 2017 Joint Statement of Issues.

ELECTRIC COOPERATIVES – MISCELLANEOUS

Issue (g): Default Remedies[1]

Witness Layton testified that Blue Ridge should be entitled to charge Charter for the cost of performing work that Charter is required to perform, but does not, under the pole attachment agreement. Witness Layton also testified that Blue Ridge should be allowed to withhold performance of make-ready work until after Charter cures any failures to perform under the contract. [Layton, Tr. Vol. 1, p. 63.] Witness Booth testified that Blue Ridge should be allowed to withhold consent for additional attachments if Charter is in default under the agreement. [Booth, Tr. Vol. 3, p. 64.]

Witness Martin proposed language intended to ensure that Blue Ridge provides reasonable notice of any alleged default and a reasonable time for cure. If Charter fails to take appropriate actions, despite notice, witness Martin proposed a number of alternative actions for Blue Ridge. [Martin, Tr. Vol. 4, pp. 107-108.] Specifically, witness Martin proposed the following language:

> ***Defaults***: *If Charter is in material default under this Agreement and fails to correct such default within the cure period specified below, the Cooperative may, at its option:*
>
> *(a) declare this Agreement to be terminated in its entirety;*
> *(b) terminate the authorization covering the pole(s) with respect to which such default shall have occurred;*
> *(c) decline to authorize additional Attachments under this Agreement until such defaults are cured;*
> *(d) suspend all make-ready construction work;*
> *(e) correct such default without incurring any liability to Charter except when caused by Cooperative's gross negligence or willful misconduct, and Charter shall reimburse Cooperative for the actual costs of doing the work; and/or*
> *(f) obtain specific performance of the terms of this Agreement through a court of competent jurisdiction.*
>
> *For a period of thirty (30) days following receipt of notice from the Cooperative (or, for defaults of a nature not susceptible to remedy within this thirty (30) day period within a reasonable time period thereafter), Charter shall be entitled to take all steps necessary to cure any defaults. The 30-day notice and cure period does not apply to any default by Charter of its payment obligations under this Agreement.* [Martin, Tr. Vol. 4, pp. 107-08.]

Witness Martin testified that his proposed language provides more options to Blue Ridge than are contained in many other pole agreements. [Martin, Tr. Vol. 4, p. 108.]

[1] Issue No. 3(g) per the November 2, 2017 Joint Statement of Issues.

Discussion and Conclusions for Issue (g)
Default remedies

Default provisions must clearly articulate proportionate consequences for failure to uphold the terms of the agreement, after a reasonable period of time to cure the issue. The Commission finds Blue Ridge's proposed remedy unreasonable under this standard. Suspending Charter's access to all of the poles on which it has existing attachments would introduce further risks for both parties, including preventing Charter from maintaining its network and addressing issues affecting both parties' systems. The Commission finds that Charter's proposed default language incentivizes good faith efforts to remediate defaults and is reasonable.

Issue (h): Confidentiality[1]

Witness Layton requested that the Commission agree with Blue Ridge that the rates, terms and conditions of any pole attachment agreement that result from this proceeding be kept confidential and therefore proposed that the Commission adopt specific language to be included in the pole attachment agreement on confidentiality. [Layton, Tr. Vol. 1, p. 63.] Witness Booth claimed that pole attachment agreements contain "market sensitive information," although he did not demonstrate any basis for his statement. [Booth, Tr. Vol. 3, p. 64.]

Witness Martin, responding on behalf of Charter, argued that keeping pole attachment agreements confidential is not "industry standard," and there is no basis for keeping Charter's agreement with Blue Ridge, or its terms, confidential. [Martin, Tr. Vol. 4, p. 109.]

Discussion and Conclusions for Issue (h)
Confidentiality

Blue Ridge has provided no basis for keeping the rates, terms and conditions of the pole agreement that results from this proceeding confidential. The Commission declines to make such a ruling. As a public agency, the Commission is bound by the North Carolina Public Records Act, N.C. Gen. Stat. § 132-1, et seq., which establishes a presumption that all agency records shall be open to the public. Blue Ridge has cited no provision of the Public Records Act supporting a conclusion that the rates, terms and conditions of the pole agreement that results from this proceeding are confidential[2] nor does the Commission find that any provision of N.C. Gen. Stat. § 62-350 establishes the ability of one party to a pole attachment agreement to unilaterally declare the terms and conditions of the agreement to be confidential. Should Blue Ridge have a legitimate concern that any element of its pole attachment agreement with Charter contains any "market sensitive information," it may request Charter to agree to keep it confidential, and if Blue Ridge is

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[1] Issue No. 3(h) per the November 2, 2017 Joint Statement of Issues.

[2] The Commission acknowledges that the General Assembly has created a statutory exemption from disclosure for certain "trade secret" information. N.C. Gen. Stat. § 132-1.2. Blue Ridge has not made a showing that the information in question qualifies under this exemption. On its face, the Commission declines to find, under this record, that the information in question is the property of a "private person" or that disclosure of the information creates any competitive concerns in light of the nature of the information at issue and the nature of the market for pole attachments.

unsatisfied with the result, it may bring the issue to the Commission. Blue Ridge's proposed language on confidentiality is therefore denied.

Issue (i): Indemnity[1]

Witnesses Layton and Booth, on behalf of Blue Ridge, testified that Charter should be required to defend and indemnify Blue Ridge for all attachments that Charter has made to Blue Ridge's poles. [Layton, Tr. Vol. 1, pp. 63-64; Booth, Tr. Vol. 3, p. 60.]

In response, witness Martin testified that each party should be responsible for its own negligence, and suggested the following language to protect the interests of both the pole owner and attachers:

> *Indemnity and Limitation of Liability: Except as otherwise specified herein, each party shall defend, indemnify and hold harmless the other party from any and all claims, liabilities, suits and damages arising from or based upon any breach of the party's obligations under the Agreement. Notwithstanding, neither party shall be liable to the other in any way for indirect or consequential losses or damages, however caused or contributed to, in connection with this Agreement or with any equipment or service governed hereby.* [Martin, Tr. Vol. 4, p. 106.]

Witness Martin testified that mutual indemnification is standard in the industry and that Blue Ridge has mutual indemnification provisions in virtually all of its agreements with joint users. [Martin, Tr. Vol. 4, p. 106.]

Discussion and Conclusions for Issue (i)
Indemnity

The Commission finds that, based on the evidence of industry standard and of similar provisions in virtually all of Blue Ridge's joint use agreements, it is appropriate to adopt Charter's proposed language on this issue.

Issue (j): Reservation of Space[2]

Witnesses Layton and Booth asserted that Blue Ridge should be allowed in its pole attachment agreement to prohibit Charter from making any new attachments closer than 72 vertical inches from Blue Ridge's neutral conductor. [Layton, Tr. Vol. 1, p. 64; Booth, Tr. Vol. 3, p. 65.] The NESC prohibits attachments of communications facilities closer than 40 vertical inches from a neutral and 30 inches from a grounded transformer. [*See* EEE, 2017 National Electrical Code, Table 235-5; Booth, Tr. Vol. 3, pp. 78-79.] Witness Booth explained that transformers are usually placed so that their tops are at the same height as the neutral conductors. [Booth, Tr. Vol. 3, p. 66.] Witness Booth maintained that Blue Ridge should be able to require Charter to attach 72 inches below the neutral for any hypothetical attachments it may plan to make in the future. [Booth, Tr. Vol. 3, pp. 181-82, 215-17.] Preventing Charter from attaching closer than 72 inches below the

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[1] Issue No. 3(i) per the November 2, 2017 Joint Statement of Issues.

[2] Issue No. 3(j) per the November 2, 2017 Joint Statement of Issues.

neutral on each Blue Ridge pole, therefore, would keep space available for a transformer on every pole that does not already contain one.[1] [Booth, Tr. Vol. 3, pp. 78-79, 181-82.] Blue Ridge witness Booth claimed on cross examination that RUS requires the top 8.5 feet or 9.5 feet of a pole to be reserved for electric equipment (including the 72 inches), but on cross examination he was not able to identify specifically any such RUS requirement. [Booth, Tr. Vol. 3, pp. 67, 189-95.][2]

Witness Martin testified that Charter is willing to accept language that would allow Blue Ridge to reclaim any space needed by Blue Ridge for its core utility service, but stated that Charter should be allowed to occupy, at least temporarily, pole space for so long as it is available. [Martin, Tr. Vol. 4, pp. 102-04.] He proposed the following language:

> *<u>New or Relocated Charter Attachments</u>: Whenever Charter installs new Attachments, transfers existing Charter Attachments to replaced poles, or relocates existing Charter Attachments to a relocated line of poles, Charter shall attach at least forty (40) inches and, preferably seventy-two (72) inches vertical clearance under the effectively grounded neutral of Cooperative.* [Martin, Tr. Vol. 4, p. 103.]

Witness Martin testified that "virtually every other communications attacher (other than Charter) is allowed to place its facilities within 40 inches of Blue Ridge's neutral."[3] [Martin, Tr. Vol. 4, p. 103.] And Blue Ridge witness Layton admitted that Charter and its predecessors have been attaching their facilities approximately 40 inches from Blue Ridge's neutral for decades and that they did not violate any RUS requirement by doing so. [Layton, Tr. Vol. 2, pp. 33-34.]

A different related issue was also explored at hearing. Recent inspections conducted on behalf of Blue Ridge have found a number of instances where Blue Ridge's electrified facilities (mostly transformers) are closer to Charter's cables than the clearances allowed by the NESC. The parties differ on whether such violations have been caused by Blue Ridge placing the facilities after Charter was already attached, or whether Charter placed its facilities too close to existing Blue Ridge facilities. [Mullins, Tr. Vol. 3, pp. 269-75; Booth, Tr. Vol. 3, pp. 120-25].[4] While Charter agrees that it is responsible for making space available for new transformers or other Blue Ridge facilities to be placed, it contends that Blue Ridge must be responsible for curing violations that it has created by failing to give Charter notice and an opportunity to decide how it wished to deal with the reclamation of space: moving its attachment, paying for a new pole, or removing its attachment from the pole. [Mullins, Tr. Vol. 3, p. 255.] Charter contends that it does not bear responsibility for curing violations created by Blue Ridge without notice *****BEGIN CONFIDENTIAL*** ***END CONFIDENTIAL*****[5]

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[1] *****BEGIN CONFIDENTIAL*** ***END CONFIDENTIAL*****

[2] *****BEGIN CONFIDENTIAL*** ***END CONFIDENTIAL*****

[3] *****BEGIN CONFIDENTIAL*** ***END CONFIDENTIAL*****

[4] The Commission expects that the parties will make a good faith effort to determine fault in each of these cases as required by N.C. Gen. Stat. § 62-350(d)(4) ("All attaching parties shall work cooperatively to determine causation of, and to effectuate any remedy for, noncompliant lines, equipment, and attachments.").

[5] *****BEGIN CONFIDENTIAL*** ***END CONFIDENTIAL*****

Discussion and Conclusions for Issue (j)
Reservation of space

The parties agree that Charter occupies space on Blue Ridge's poles only so long as that space is not required by the Cooperative for its electric service. The Commission does not find Blue Ridge's apparent position that it should be allowed to prohibit even temporary occupancy of the top 8.5 feet or 9.5 feet on a pole, to the extent that Blue Ridge has no present or impending need for it, reasonable. The Commission finds Blue Ridge's position on this issue inconsistent with the access rights afforded to Charter in N.C. Gen. Stat. § 62-350. In addition, the FCC has addressed this issue stating that, "[w]e will permit the electric utility to reserve space if such reservation is consistent with a bona fide development plan . . . . The electric utility must permit use of its reserved space by cable operators . . . until such time as the utility has an actual need for that space." Implementation of the Local Competition Provisions in the Telecommunications Act of 1996, 11 FCC Rcd. 15499, 16053, ¶ 1169 (1996). Further, the Commission agrees with Charter's position that reclamation of space by Blue Ridge must be for a use related to the provision of its core electric service. Especially in light of the testimony Blue Ridge has allowed its affiliate, which provides dark fiber communications service that could compete with Charter, to attach, it would be unreasonable for the Cooperative to deny Charter access to its poles with the intention of competing directly with it. Accordingly, the Commission finds it appropriate to adopt Charter's proposed language on this issue.

Based on the record in this proceeding, the Commission finds that the next pole attachment agreement between the parties should make Charter responsible for making space for new Blue Ridge attachments according to the language proposed by Charter. To provide clarification on this issue, the Commission specifies that Charter should not be held responsible for curing violations of NESC separation requirements that have been caused by Blue Ridge placing its facilities too close to Charter's facilities without any appropriate notice or opportunity for Charter to remedy. Where Blue Ridge has taken such action in the past, or does so in the future, it should bear the responsibility for cure.

Issue (k): Recovery of Space[1]

Witnesses for both parties agree that Blue Ridge has, and should have, the right to reclaim any space used by Charter when needed for its utility service. [Martin, Tr. Vol. 4, pp. 101-02; Booth, Tr. Vol. 3, p. 64.] Charter proposed the following language that would require Charter to rearrange its facilities (including paying for a new pole, if necessary), or vacate the pole, on 30 days' notice to accommodate Blue Ridge's need for more pole space.

> *Reservation of Space: Should the Cooperative, at any time, reasonably require the space Charter's Attachments occupy on its poles for the provision of its core electric service, Charter shall, upon receipt of thirty (30) days' notice (a) rearrange its Attachments to other space if available on the pole, at its own expense, (b) vacate the space by removing its Attachments at its own expense or (c) if no space is available and Charter does not wish to remove its Attachments, Charter may request the Cooperative replace the pole with a larger pole that can accommodate*

[1] Issue No. 3(k) per the November 2, 2017 Joint Statement of Issues.

Charter's Attachments. Charter shall bear the expense of such replacement and transfer its Attachments to the new pole. [Martin, Tr. Vol. 4, p. 102.][1]

Witness Martin noted that this language is similar to the parties' 2008 pole attachment agreement, which also provides for 30 days' notice. [Martin, Tr. Vol. 4, p. 101; MM Ex. 1.] Witness Martin also maintained that Charter should not be required to pay for the recovery of space to be used for Blue Ridge's competitive communications service, Ridgelink, as that would allow Blue Ridge to favor itself in the provision of competitive communications services. [Martin, Tr. Vol. 4, p. 101; *see* N.C. Gen. Stat. § 62-350(a).] Witness Booth stated on direct examination that if Blue Ridge requires additional space on the pole, Charter should remove or rearrange its attachments "within a time certain to allow Blue Ridge to use the space," or "immediately." [Booth, Tr. Vol. 3, pp. 64, 105.] Witness Booth testified this was necessary because of the safety violations it attributes to Charter. [Booth, Tr. Vol. 3, pp. 105-06.]

Discussion and Conclusions for Issue (k)
Recovery of space

The parties agree that Blue Ridge can reclaim any space used by Charter if Blue Ridge needs it for the provision of its core utility service. The difference between the parties' positions here is the amount of notice which Blue Ridge must give to Charter. Charter proposes that Blue Ridge give it 30 days' notice to rearrange or remove its attachments, or request that Blue Ridge replace the pole at Charter's expense. Blue Ridge argues that Charter should be required to vacate the space immediately. The Commission finds the parties' prior agreement indicative of industry norms and inherently reasonable.[2] Further, the Commission agrees with Charter's position that the recovery of space by Blue Ridge must be for a use related to the provision of its core electric service. Should Blue Ridge construct communications facilities that could compete with Charter, it would be unreasonable for the Cooperative to deny Charter access to its poles with the intention of competing directly with it. Accordingly, the Commission finds it appropriate to adopt Charter's proposed language on this issue.

<u>Issue (l): Unauthorized Attachments</u>[3]

Through witness Layton, Blue Ridge seeks permission to impose penalties for attachments made by Charter without permission of both an unspecified "unauthorized attachment fee" and "back rent." [Layton, Tr. Vol. 1, p. 65.] Witness Layton asserts that if Charter is required only to pay back rent, it will have "perverse . . . incentives" to fail to seek authorization. [Layton, Tr. Vol. 1, p. 65.]

Witness Martin testified that Charter is willing to pay unauthorized attachment penalties in certain circumstances, but that the amount must be reasonable. [Martin, Tr. Vol. 4, pp. 95-96.] He proposed the following language:

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[1] ***BEGIN CONFIDENTIAL*** ***END CONFIDENTIAL***

[2] ***BEGIN CONFIDENTIAL*** ***END CONFIDENTIAL***

[3] Issue No. 3(l) per the November 2, 2017 Joint Statement of Issues.

Unauthorized Attachments: The Cooperative may assess a fee for any Charter Attachment that has not been authorized in accordance with this Agreement ("Unauthorized Attachment"). The fee for Unauthorized Attachments shall be equal to five (5) times the current Annual Attachment Fee and shall be imposed in a non-discriminatory manner as to all attachers. [Martin, Tr. Vol. 4, p. 96.]

Discussion and Conclusions for Issue (l)
Unauthorized attachments

The primary difference in the positions of the parties on unauthorized attachments is the magnitude of the penalty. Blue Ridge seeks back rent, plus an unspecified penalty amount per unauthorized attachment. Charter seeks the traditional FCC standard of five years of back rent. For the following reasons, the Commission finds the language proposed by Charter to be just and reasonable.

Any claims for liquated damages that are penalties unrelated to actual damage are impermissible. No costs (above and beyond lost rental payments) have been established. Furthermore, assuming that pole attachment audits are conducted on a regular basis, and also that some attachments made without authorization were made more recently than five years ago, a five year attachment back rental, such as Charter proposes, is itself a penalty and a disincentive for Charter not to obtain authorization.

Blue Ridge has failed to justify any amount of "liquidated damages" for unauthorized attachments or noncompliant attachments. *See* Chris v. Epstein, 113 N.C. App. 751, 757, 440 S.E. 2d 581, 584-85 (N.C. Ct. App. 1994). Liquidated damages may be appropriate where the damages are reasonably difficult to ascertain because of their indefiniteness or uncertainty and where the amount is either a reasonable estimate of the damages that would probably be caused as a result of a breach or is reasonably proportionate to the damages actually caused by the breach. Knutton v. Cofield, 273 N.C. 355, 360-61, 160 S. E.2d 29, 34 (N.C. Ct. App. 1968). While Blue Ridge introduced scores of photographs in this hearing of alleged safety violations by Charter, it made no attempt to quantify the costs to correct these violations, nor did it produce any evidence of amounts it spent in the past to remedy such violations. As a result, Blue Ridge has not made a reasonable effort to show that any amount of liquidated damages is a reasonable estimate of the damages that Charter has caused or will cause or that proposed liquidated damages are reasonably proportionate to the damages actually caused by Charter's breach. Damages which bear no relationship to the actual harm that is suffered and are imposed to facilitate Charter's compliance with the agreement are a penalty. Penalty clauses included in contracts that are denominated as liquidated damages are unenforceable. Knutton v. Cofield, 273 N.C. 355, 360-61, 160 S. E.2d 29, 34 (N.C. Ct. App. 1968). The Commission also notes that double recovery of actual and liquidated damages is not permitted under North Carolina law. Handex of Carolinas, Inc. v. Cnty. of Haywood, 168 N.C. App. 1, 4, 607 S.E. 2d 25, 28 (N.C. Ct. App. 2005).

Assuming that Blue Ridge conducts attachment inventories on a regular five-year cycle, and assuming that new attachments are made on a regular basis throughout that time period, the penalty proposed by Charter (of five times the annual rate for each unauthorized attachment) will average a recovery of double the annual payment that would otherwise have been paid. Based on the evidence, including Charter's explicit agreement, the Commission finds that that penalty should create a sufficient incentive to Charter. Further, the evidence reflects that such an unauthorized attachment fee is industry-standard. Accordingly, for the aforementioned reasons, the Commission finds it appropriate to adopt Charter's proposed unauthorized attachment fee language.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 35

The evidence supporting this Finding of Fact is found in the testimony of witnesses Booth, Layton and Mullins.

Witness Booth testified that the photographs included in his exhibits illustrate various safety violations by Charter. [Booth, Tr. Vol. 3, pp. 77-82; *see* GLB Ex. 3.] Witness Mullins testified that Charter had not had an opportunity to fully review the situations presented by the photographs in witness Booth's hearing exhibits, but that he believed that much of the noncompliance depicted was created by Blue Ridge and other attachers. [Mullins, Tr. Vol. 3, pp. 267-77.] Witness Layton testified that the purpose of at least one of the safety inspections "was for this litigation." [Layton, Tr. Vol. 1, p. 199.]

Discussion and Conclusions

The issues raised by Blue Ridge regarding the condition and compliance of Charter's outside plant are not ripe for Commission consideration. N.C. Gen. Stat. § 62-350 sets forth required processes and procedures for dealing with noncompliant attachments and disputes as to the cause of the noncompliance. As stated above, the Commission has insufficient basis to determine causation and responsibility for any compliance issues, but understands that the parties are working to remedy any violations that do exist. [Layton, Tr. Vol. 1, p. 91; Mullins, Tr. Vol. 3, pp. 254-56.]

The Commission is confident that the parties will work cooperatively to determine the causation and appropriate remedy for any noncompliant attachments, as directed by N.C. Gen. Stat. § 62-350(d)(4).

IT IS, THEREFORE, ORDERED as follows:

1. That Blue Ridge's maximum just and reasonable pole attachment rates for the years 2015-2017 should be determined based on the FCC Rate Methodology, as modified to reflect the actual data provided by Blue Ridge. Therefore, the Commission finds that the following rates are the appropriate maximum just and reasonable rates: $8.49 per year per pole for rate year 2015, $8.37 per year per pole for rate year 2016, and $8.31 per year per pole for rate year 2017.

2. That Blue Ridge owes a refund to Charter for excessive pole attachment fees paid from August 25, 2015, to August 31, 2017, in an amount to be calculated by the parties, and for excessive pole attachment fees paid after August 31, 2017. If Blue Ridge desires, and Charter is agreeable, the refund may be used as a credit against future pole attachment bills until the amount of the credit is fully exhausted.

3. That in addition to a just and reasonable pole attachment rate, it is appropriate for Charter to pay Blue Ridge's measurable and verifiable costs directly attributable to Blue Ridge providing pole attachment space to Charter.

4. That for Issues (b), (d), (e), (g), (i), (j), (k), and (l), the language proposed by Charter for the disputed terms and conditions is hereby approved and adopted. With respect to Issue (c), the language set forth by Blue Ridge is hereby approved and adopted.

5. That the parties shall negotiate appropriate language to include in their pole attachment agreement based on the Commission's conclusions outlined herein for Issues (a) and (f).

6. That Blue Ridge's proposal to have the rate, terms, and conditions of the parties' pole attachment agreement deemed confidential (Issue (h)) is hereby denied.

ISSUED BY ORDER OF THE COMMISSION.
This the 17th day of October, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

Commissioner Bryan E. Beatty resigned from the Commission on January 31, 2018 and did not participate in the decision.

DOCKET NO. EMP-93, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Wilkinson Solar, LLC, for Registration of a New Renewable Energy Facility	)))	ORDER ACCEPTING REGISTRATION OF NEW RENEWABLE ENERGY FACILITY

BY THE CHAIRMAN: On March 13, 2017, Wilkinson Solar, LLC, (Applicant), filed a registration statement pursuant to Commission Rule R8-66, seeking to register its 74-MW_{AC} solar photovoltaic (PV) electric generating facility located in Beaufort County, North Carolina, as a new renewable energy facility. The Applicant stated that its facility is expected to become operational on December 31, 2018.

The Applicant's filing included certified attestations that: 1) the facility is in substantial compliance with all federal and state laws, regulations, and rules for the protection of the environment and conservation of natural resources; 2) the facility will be operated as a new renewable energy facility; 3) the Applicant will not remarket or otherwise resell any RECs sold to an electric power supplier to comply with G.S. 62-133.8; and 4) the Applicant will consent to the auditing of its books and records by the Public Staff insofar as those records relate to transactions with North Carolina electric power suppliers.

On May 4, 2017, the Public Staff filed the prefilled direct testimony of Evan D. Lawrence, an engineer with the Public Staff-Electric Division. Witness Lawrence's testimony included the recommendation required by Commission Rule R8-66(e), stating that the Public Staff-Electric Division has completed its review of the Applicant's registration statement. Based upon this review, witness Lawrence recommended that the Applicant's registration statement be considered complete and that the facility be considered a new renewable energy facility. No other party made a filing with respect to these issues.

Based upon the foregoing and the entire record in this proceeding, the Chairman finds good cause to accept the registration statement filed by the Applicant for its 74-MW_{AC} solar PV facility to be registered as a new renewable energy facility. The Applicant shall annually file the information required by Commission Rule R8-66 on or before April 1 of each year. To the extent that the Applicant is not otherwise participating in a REC tracking system, it will be required to participate in the NC-RETS REC tracking system (www.ncrets.org) in order to facilitate the issuance of RECs.

IT IS, THEREFORE, ORDERED as follows:

1. That the registration statement filed by Wilkinson Solar, LLC for its 74-MW_{AC} solar photovoltaic (PV) electric generating facility located in Beaufort County, North Carolina, to be registered as a new renewable energy facility shall be, and is hereby, accepted;

2. That Wilkinson Solar, LLC, shall annually file the information required by Commission Rule R8-66 on or before April 1 of each year; and

3. That the Chief Clerk shall transmit a copy of this Order to the NC-RETS Administrator.

ISSUED BY ORDER OF THE COMMISSION.
This the 27th day of December, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

ELECTRIC RESELLER – CERTIFICATE

DOCKET NO. ER-68, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
The Standard at Boone, LLC, for Authority	)	
to Resell Electric Service Pursuant to	)	ORDER GRANTING
G.S. 62-110(h) at The Standard at Boone,	)	CERTIFICATE OF AUTHORITY
828 Blowing Rock Road, Boone, NC 28607	)	

BY THE COMMISSION: On August 10, 2016, The Standard at Boone, LLC (The Standard or Applicant), filed an application for a certificate of authority to resell electric service at The Standard at Boone, located at 828 Blowing Rock Road, Boone, NC 28607, in accordance with G.S. 62-110(h) and Chapter 22 of the Commission's rules. On September 28, 2016, the Public Staff of the North Carolina Utilities Commission (Public Staff) filed its correspondence to the Applicant outlining the deficiencies in The Standard's application. On October 6, 2016, the Commission issued an Order finding The Standard's application incomplete and requesting additional information.

The Applicant submitted supplemental filings on October 17 and November 15, 2016; June 23 and October 24, 2017; and April 19 and July 12, 2018.

On July 16, 2018, the Public Staff filed a letter opining that The Standard's application is complete and complies with the requirements of G.S. 62-110(h) and Chapter 22 of the Commission's rules. For these reasons, the Public Staff in its letter of July 16, 2018, recommended that the Commission approve The Standard's application, as amended and supplemented by its filings of October 17 and November 15, 2016; June 23 and October 24, 2017; and April 19 and July 12, 2018.

Based upon a review of The Standard's application and supplemental filings and the Public Staff's recommendation, the Commission finds that, with two exceptions, the application is complete and complies with the requirements of G.S. 62-110(h) and Chapter 22 of the Commission's rules. Specifically, in the SimpleBills sample bill statement submitted by the Applicant on July 12, 2018, the Commission notes that the bill statement appears to be due less than 25 days following the date of its issuance, in violation of G.S. 62-110(h)(4)d.; in addition, the amount of days remaining to pay the bill before the bill becomes past-due appears to be an incorrect calculation. Therefore, the Commission concludes that The Standard's application should be approved, on the condition that the Applicant, prior to reselling electric service at The Standard at Boone, first correct the SimpleBills bill statement to rectify these two additional deficiencies.

Based upon the foregoing and the entire record in this docket, the Commission finds good cause to issue to the Applicant a certificate of authority to resell electric service at The Standard at Boone, subject to the modifications required in a manner consistent with this Order.

ELECTRIC RESELLER – CERTIFICATE

IT IS, THEREFORE, ORDERED as follows:

1. That the Applicant shall, within 10 days following the date of this Order, make a compliance filing containing a revised SimpleBills bill statement to correct the due date and days remaining in a manner consistent with this Order;

2. That, subject to the modifications to the SimpleBills bill statement as required by this Order and evidenced through the Applicant's forthcoming compliance filing, the application filed by the Applicant to resell electric service at The Standard at Boone, located at 828 Blowing Rock Road, Boone, NC 28607, is hereby granted; and

3. That this order shall constitute the Certificate of Authority to Resell Electric Service issued to The Standard.

ISSUED BY ORDER OF THE COMMISSION.
This the 23rd day of July, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

DOCKET NO. G-9, SUB 727

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Piedmont Natural Gas Company, Inc. for Annual Review of Gas Costs Pursuant to N.C.G.S. § 62-133.4(c) and Commission Rule R1-17(k)(6)	))))	ORDER ON ANNUAL REVIEW OF GAS COSTS

HEARD: Tuesday, October 2, 2018, at 10:00 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding, Commissioner Lyons Gray and Commissioner Charlotte A. Mitchell

APPEARANCES:

For Piedmont Natural Gas Company, Inc.:

James H. Jeffries IV, McGuireWoods LLP, 201 N. Tryon Street, Suite 3000, Charlotte, North Carolina 28202

Brian S. Heslin, Duke Energy Corporation, 550 S. Tryon Street, Charlotte, North Carolina 28202

For the Using and Consuming Public:

Elizabeth D. Culpepper, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699

For Carolina Utility Customers Association, Inc.

Robert F. Page, Crisp & Page, PLLC, 4010 Barrett Drive, Suite 205, Raleigh, North Carolina 27609

BY THE COMMISSION: On August 1, 2018, pursuant to N.C. Gen. Stat.§ 62-133.4(c) and Commission Rule R1-17(k)(6), Piedmont Natural Gas Company, Inc. (Piedmont or Company), filed the direct testimonies and exhibits of MaryBeth Tomlinson, Manager of Gas Accounting; Gennifer Raney, Director of Pipeline Services; and Sarah E. Stabley, Managing Director of Gas Supply Optimization and Pipeline Services. Piedmont's witnesses attested to the prudence of the Company's gas purchasing practices and the accuracy of the Company's gas cost accounting for the twelve-month period ended May 31, 2018 (review period).

On August 7, 2018, the Commission issued its Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines and Requiring Public Notice. This Order established a hearing date of October 2, 2018, set prefiled testimony dates, and required the Company to give notice to its customers of the hearing on this matter.

On August 23, 2018, Carolina Utility Customers Association, Inc. (CUCA) filed a petition seeking to intervene in this docket. On August 24, 2018, the Commission issued an Order Granting Petition to Intervene.

On September 17, 2018, the Public Staff filed the prefiled joint testimony of Poornima Jayasheela, Staff Accountant, Natural Gas Section, Accounting Division; Zarka H. Naba, Public Utilities Engineer, Natural Gas Division; and Michael C. Maness, Director, Accounting Division (Public Staff Panel or Panel). The Public Staff revised its filed testimony on October 1, 2018.

On September 24, 2018, the Commission issued its Order Providing Notice of Commission Questions.

On September 27, 2018, September 28, 2018, October 1, 2018, and October 2, 2018, numerous consumer statements of position were filed with the Commission.

On September 28, 2018 and October 1, 2018, Piedmont filed written responses to the Commission's September 24, 2018 questions.

On October 1, 2018, the Company filed its affidavits of publication.

On October 2, 2018, this matter came on for hearing as scheduled, and all prefiled testimony and exhibits were admitted into evidence. Public witness Cathy Buckley testified on behalf of members of the Sierra Club.

On November 28, 2018, the Joint Proposed Order of Piedmont and the Public Staff was filed.

On December 7, 2018, the Public Staff filed a motion requesting that the Commission accept corrections to its pre-filed testimony. The Commission issued an order on December 11, 2018, accepting the Public Staff's corrected testimony.

Based on the testimony and exhibits received into evidence and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. Piedmont is a public utility as defined in Chapter 62 of the North Carolina General Statutes and is subject to the jurisdiction and regulation of the Commission.

2. Piedmont is engaged primarily in the business of transporting, distributing, and selling natural gas to customers in North Carolina, South Carolina, and Tennessee.

3. Piedmont has filed with the Commission and submitted to the Public Staff all of the information required by N.C.G.S. § 62-133.4(c) and Commission Rule R1-17(k).

4. The review period in this proceeding is the twelve months ended May 31, 2018.

5. The Company properly accounted for its gas costs incurred during the review period.

6. During the review period, the Company incurred total North Carolina gas costs of $343,478,124, which was comprised of demand and storage charges of $129,398,029, commodity gas costs of $220,382,071, and other gas costs of ($6,301,977).

7. At May 31, 2018, the Company had a credit balance of $15,300 owed from the Company to the customers in its Sales Customers Only Deferred Account, and a credit balance of $17,078,428, owed from the Company to the customers, in its All Customers Deferred Account.

8. During the review period, Piedmont actively participated in secondary market transactions earning actual margins of $32,831,848 for the benefit of North Carolina ratepayers.

9. Piedmont operated a gas cost hedging program on behalf of customers during the review period. Piedmont's hedging activities during the review period were reasonable and prudent.

10. At May 31, 2018, the balance in the Company's Hedging Deferred Account was a debit balance of $5,207,171.

11. It is appropriate for the Company to include the $5,207,171 debit balance in its Hedging Deferred Account in its Sales Customers Only Deferred Account. The combined balance for the Hedging and Sales Customers Only Deferred Accounts is a net debit balance of $5,191,871.

12. The Company has transportation and storage contracts with interstate pipelines, which provide for the transportation of gas to the Company's system, and long-term supply contracts with producers, marketers, and other suppliers.

13. The Company utilized a "best cost" gas purchasing policy during the applicable review period consisting of five main components: price of gas, security of the gas supply, flexibility of the gas supply, gas deliverability, and supplier relations.

14. The Company's gas purchasing policy and practices during the review period were prudent.

15. The Company's capacity acquisition planning and arrangements are reasonable and prudent.

16. The Company's gas costs during the review period were prudently incurred, and the Company should be permitted to recover 100% of such prudently incurred gas costs.

17. The Company should implement the temporary rate decrement and increments as proposed by Company witness Tomlinson and agreed to by the Public Staff Panel.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-2

The evidence supporting these findings of fact is contained in the official files and records of the Commission and the testimony of Company witnesses Tomlinson, Raney, and Stabley. These findings are essentially informational, procedural, or jurisdictional in nature and are not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3-4

The evidence supporting these findings of fact is contained in the testimony of Company witnesses Tomlinson, Raney, and Stabley, and the revised testimony of the Public Staff Panel. These findings are made pursuant to N.C.G.S. § 62-133.4(c) and Commission Rule R1-17(k)(6).

Pursuant to N.C.G.S. § 62-133.4, Piedmont is required to submit to the Commission information and data for an historical 12-month review period including Piedmont's actual cost of gas, volumes of purchased gas, sales volumes, negotiated sales volumes, and transportation volumes. Commission Rule R1-17(k)(6)(a) establishes May 31, 2018, as the end date of the annual review period for the Company in this proceeding. Commission Rule R1-17(k)(6)(c) requires that Piedmont file weather-normalized data, sales volumes, work papers, and direct testimony and exhibits supporting the information.

Company witness Tomlinson testified that the Company filed with the Commission and submitted to the Public Staff throughout the review period complete monthly accountings of the computations required by Commission Rule R1-17(k)(6)(c). Witness Tomlinson included the annual data required by Commission Rule R1-17(k)(6)(c) as Exhibit_(MBT-1) to her direct testimony. The Public Staff Panel stated that they had presented the results of their review of the gas cost information filed by Piedmont in accordance with N.C.G.S. § 62-133.4(c) and Commission Rule R1-17(k)(6).

Based upon the foregoing, the Commission concludes that Piedmont has complied with the procedural requirements of N.C.G.S. § 62-133.4(c) and Commission Rule R1-17(k) for the 12-month review period ended May 31, 2018.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-7

The evidence supporting these findings of fact is contained in the testimony of Company witness Tomlinson and the revised Public Staff Panel testimony.

Company witness Tomlinson testified that Piedmont incurred total North Carolina gas costs of $343,478,124 during the review period, which was comprised of demand and storage charges of $129,398,029, commodity gas costs of $220,382,071, and other gas costs of ($6,301,977).[1]

[1] Immaterial difference of $1 between this total and the individual components listed is due to rounding of amounts shown on Exhibit_ (MBT – 1), Schedule 1.

The Public Staff's testimony included a thorough analysis of Piedmont's gas costs. The testimony showed that the level of demand and storage charges were down 2.6% from the level in last year's annual review in Docket No. G-9, Sub 710. The bulk of the reduction was attributed to changes in the costs of four sources of capacity. The most significant cost reduction was a $1,789,913 reduction in the rates paid to Cardinal Pipeline Company LLC as a result of a general rate case in Docket No. G-39, Sub 38. The costs of Piedmont's capacity from Pine Needle LNG, which is regulated by the Federal Energy Regulatory Commission (FERC), decreased $1,451,281 as a result of a change in Pine Needle LNG's Electric power and Fuel Tracker in FERC Docket No. RP17-576. The reduction of $491,283 in Transcontinental Gas Pipe Line Company, LLC (Transco) Firm Transportation charges was the result of a reduction in the electric component of the reservation charge in FERC Docket No. RP18-541. The reduction of $470,996 in Columbia Gulf was the result of the termination of the Columbia Gulf contract, effective October 31, 2017.

The Commission notes that the overall demand and storage costs paid by Piedmont have increased in recent years as additional capacity was added to accommodate growth. In Piedmont's Docket No. G-9, Sub 690, which covered a 12-month review period ending May 31, 2016, demand and storage costs rose to approximately $133.2 million from $124.5 million during the previous review period. This increase was mostly attributable to the cost of adding 100,000 dts/day on Transco's Leidy Southeast project.

Witness Tomlinson's prefiled testimony and exhibits reflected a debit balance of $5,191,871 in Piedmont's Sales Customers Only Deferred Account and a credit balance of $17,078,428 in its All Customers Deferred Account as of May 31, 2018. The Public Staff Panel agreed with these balances and testified that the Company properly accounted for its gas costs incurred during the review period.

Based upon the foregoing, the Commission concludes that the Company properly accounted for its gas costs incurred during the review period. The Commission also concludes that the appropriate level of total North Carolina gas costs incurred for this proceeding is $343,478,124. The Commission further concludes that the appropriate deferred account balances as of as of May 31, 2018, are a debit balance of $5,191,871, owed from the customers to the Company, in its Sales Customers Only Deferred Account, and a credit balance of $17,078,428, owed from the Company to the customers, in its All Customers Deferred Account.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting this finding of fact is contained in the testimony of Company witness Stabley and the revised Public Staff Panel testimony.

Company witness Stabley provided testimony on the process that Piedmont utilized and the market intelligence that was evaluated during the review period to determine the prices charged for off-system sales. Witness Stabley explained that the process and information used by Piedmont in pricing off-system sales depends upon the location of the sale, term and type of the sale, and prevailing market conditions at the time of the sale. Witness Stabley stated that for long-term delivered sales (longer than one month), Piedmont generally solicits bids from potential buyers and, if acceptable, awards volumes based on bids received and its evaluation. Witness Stabley further stated that, for short-term transactions (daily or monthly), Piedmont monitors prices and volumes on the Intercontinental Exchange, as well as by talking to various market participants and, for less liquid trading points, estimating prices based on price relationships with more liquid points. The Company also evaluates the amount of supply available for sale and weighs that against current market conditions in formulating its sales strategy.

The Public Staff Panel testified that the Company earned actual total company margins of $51,420,263 on secondary market transactions and credited the All Customers Deferred Account in the amount of $32,831,848 for the benefit of North Carolina ratepayers (($51,420,263 – 100% of Duke Off System Sales) x NC demand allocator x 75% ratepayer sharing percent) + (100% Duke Off System Sales X NC demand allocator)). The margins earned were a result of Piedmont's participation in asset management arrangements, capacity releases, and off system sales. As explained in Company witness Tomlinson's testimony, Piedmont has reported in Piedmont's Deferred Gas Cost accounts all of the margins received by Piedmont on secondary market sales and capacity release to DEC and DEP for the benefit of customers without any benefit to or sharing by Piedmont as of October 2016, the month in which the Duke Energy/Piedmont merger was consummated.

The Public Staff's analysis showed significant changes in amount of margins received from the three types of secondary market activities that Piedmont engaged in during the review period compared to the previous review period. While capacity releases still accounted for the single largest amount at $20,465,242, margins from those transactions were down by 15%. Margins from Asset Management Agreements, at $10,885,208, were down 41%. Margins from off-system sales, at $20,069,813, were up over 186%. In total, Piedmont's margins from secondary market transactions were up 3.8%.

Based on the foregoing, the Commission concludes that Piedmont actively participated in secondary market transactions, resulting in $32,831,848 of margin for the benefit of North Carolina ratepayers during the review period.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9-11

The evidence supporting these findings of fact is contained in the testimony of Company witnesses Tomlinson and Stabley and the revised Public Staff Panel testimony.

Company witness Tomlinson stated in her testimony that the Company had a debit balance of $5,207,171 in its Hedging Deferred Account at May 31, 2018. The Public Staff Panel testified that the net hedging costs were composed of Economic Gains on Closed Positions of ($114,950), Premiums Paid of $5,016,010, Brokerage Fees and Commissions of $69,440, and Interest on the Hedging Deferred Account of $236,671.

Company witness Stabley testified that Piedmont's Hedging Plan accomplished its goal of providing an insurance policy to reduce gas cost volatility for customers in the event of a gas price fly up. Witness Stabley testified that the Company did not make any changes to its Hedging Plan during the review period. Witness Stabley further testified that the Company continues to utilize storage as a physical hedge to stabilize cost, and that the Company's Equal Payment Plan, the use of the Purchased Gas Adjustment benchmark price, and deferred gas cost accounting also provide a smoothing effect on gas prices.

The Public Staff Panel testified that its review of the Company's hedging activities is performed on an ongoing basis and includes analysis and evaluation of information contained in several documents and other data. These include the Company's monthly hedging deferred account reports, detailed source documentation, work papers supporting the derivation of the maximum targeted hedge volumes for each month, and periodic reports on the status of hedge coverage for each month. In addition, the Public Staff reviews periodic reports on the market values of the various financial instruments used by the Company to hedge, monthly Hedging Program Status Reports, monthly reports reconciling the Hedging Program Status Report and the hedging deferred account report. Further, the Public Staff reviews minutes from the meetings of Piedmont's Gas Market Risk Committee (GMRC), which was formerly the Energy Price Risk Management Committee, minutes from the meetings of the Board of Directors and its committees that pertain to hedging activities, reports and correspondence from the Company's internal and external auditors, hedging plan documents, communications with Company personnel regarding key hedging events and plan modifications under consideration by the GMRC, and the testimony and exhibits of the Company's witnesses in the annual proceeding.

The Public Staff Panel concluded that Piedmont's hedging activities were reasonable and prudent and recommended that the $5,207,171 debit balance in the Hedging Deferred Account as of the end of the review period be transferred to the Sales Customers Only Deferred Account. Based on this recommendation, the Panel stated that the combined balance in the Sales Customers Only Deferred Account as of May 31, 2018 is a net debit balance, owed to the Company, of $5,191,871.

As demonstrated by the testimony and exhibits provided by Piedmont and the Public Staff's revised testimony, the Commission finds that Piedmont's hedging program has met the objective of contributing to the mitigation of gas price volatility and avoiding rate shock to customers. The Commission concludes that Piedmont's hedging activities were reasonable and prudent and that the $5,207,171 debit balance in the Hedging Deferred Account as of the end of the review period should be transferred to the Sales Customers Only Deferred Account. The combined balance for the Hedging and Sales Customers Only Deferred Accounts is a net debit balance of $5,191,871, owed to the Company.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-16

The evidence supporting these findings of fact is contained in the testimony of Company witnesses Stabley and Raney, the Company's responses to the Commission's September 24, 2018 questions, and the revised Public Staff Panel testimony.

Company witness Stabley testified that the Company maintains a "best cost" gas purchasing policy. This policy consists of five main components: price of the gas; security of the gas supply; flexibility of the gas supply; gas deliverability; and supplier relations. Witness Stabley testified that all of these components are interrelated and that the Company weighs the relative importance of each of these factors in developing its overall gas supply portfolio to meet the needs of its customers.

Witness Stabley also described how the interrelationship of the five factors of Piedmont's "best cost" policy affects the Company's construction of its gas supply and capacity portfolio under its best cost policy. The long-term contracts, supplemented by long-term peaking services and storage, generally are aligned with the firm market; the short-term spot gas generally serves the interruptible market. In order to weigh and consider the five factors, the Company stays abreast of current issues facing the natural gas industry by intervening in all major FERC proceedings involving its pipeline transporters, maintaining constant contact with existing and potential suppliers, monitoring gas prices on a real-time basis, subscribing to industry literature, following supply and demand developments, and attending industry seminars. Witness Stabley further testified that the Company did not make any changes in its best cost gas purchasing policies or practices during the review period.

Gas Supply

Witness Stabley further testified that the Company purchases gas supplies under a diverse portfolio of contractual arrangements with a number of reputable gas producers and marketers. In general, under the Company's firm gas supply contracts, Piedmont may pay negotiated reservation fees for the right to reserve and call on firm supply service up to a maximum daily contract quantity (nominated either on a monthly or daily basis), with market-based commodity prices tied to indices published in industry trade publications. Some of these firm contracts are for winter only (peaking or seasonal) service and some provide for 365 day (annual) service. Firm gas supplies are purchased for reliability and security of service and are generally priced on a reservation fee basis according to the amount of nomination flexibility built into the contract with daily swing service generally being more expensive than monthly baseload service.

Witness Stabley testified that the Company identifies the volume and type of supply that it needs to fulfill its market requirements and generally solicits requests for proposals from a list of suppliers that the Company continuously updates as potential suppliers enter and leave the market place. The type of supply is classified as either baseload or swing. Witness Stabley stated that swing supplies priced at first of month indices command the highest reservation fees because suppliers incur all the price risk associated with market volatility during the delivery period.

Witness Stabley testified that lower reservation fees are also associated with swing contracts based upon daily market conditions since both buyer and seller assume the risk of daily market volatility. Witness Stabley stated that after forecasting the ultimate cost delivered to the city gate for each point of supply and evaluating the cost of the reservation fees associated with each type of supply and its corresponding bid, the Company makes a "best cost" decision on which type of supply and supplier best fulfills its needs. Company witness Stabley also testified regarding the current U.S. supply situation and the various pricing alternatives available, such as fixed prices, monthly market indexing, and daily spot market pricing.

Pipeline and Storage Capacity

Company witness Raney testified about the market requirements of Piedmont's North Carolina customers and the acquisition of capacity to serve those markets. Witness Raney also testified that the Company expects the economy to continue recovering and to result in potentially increasing residential, commercial, and industrial demand, and in turn, result in greater firm temperature sensitive requirements that will require firm sales service from the Company.

Witness Raney further testified that Piedmont and the natural gas industry have not seen evidence that conservation/reduced usage occurs during design day conditions. Witness Raney testified that for that reason Piedmont is confident the conservative approach to design day forecasting is the most prudent approach.

Witness Raney testified that the Company currently believes that it has sufficient supply and capacity rights to meet its near-term customer needs into the 2018-2019 winter period. Witness Raney testified that in light of prospective growth requirements, Piedmont reviewed new capacity options in addition to continuous monitoring of interstate pipeline and storage capacity offerings. Witness Raney further stated that the Company subscribed to the Leidy Southeast Expansion Project (Leidy Southeast) of Transco, for 100,000 dekatherms (dts) per day of year-around capacity and 20,000 dts per day on Transco's Virginia Southside Expansion Project (Virginia Southside). Witness Raney testified that previously contracted capacity for Leidy Southeast and Transco's Virginia Southside went into service in late 2015 and 2016. The Company signed a Precedent Agreement with the Atlantic Coast Pipeline (ACP) in October 2014 for 160,000 dts of firm capacity, which is scheduled to go in service in November 2019. Witness Raney testified that growth projections begin to show a capacity deficit beginning in the 2019-2020 timeframe if the ACP capacity does not go into service as projected.

Witness Raney testified that capacity additions are acquired in "blocks" of additional transportation, storage, or LNG capacity, as they become needed, to ensure Piedmont's ability to serve its customers based on the options available at that time. Witness Raney explained that as a practical matter, this means that at any given moment in time, Piedmont's actual capacity assets will vary somewhat from its forecasted demand capacity requirements. Witness Raney also stated that this aspect of capacity planning is unavoidable, but Piedmont attempts to mitigate the impact of any mismatch through its use of bridging services, capacity release, and off-system sales activities.

Witnesses Raney and Stabley also indicated that during the past year the Company has taken several additional steps to manage its costs, including, actively participating in proceedings at the FERC and other regulatory agencies that could reasonably be expected to affect the Company's rates and services, promoting more efficient peak day use of its system, and utilizing the flexibility within its existing supply and capacity contracts to purchase and dispatch gas, and release capacity in the most cost-effective manner.

Ms. Cathy Buckley testified as a public witness. Witness Buckley testified that she is not a customer of Piedmont, but, rather was testifying as a representative of the Sierra Club. In summary, witness Buckley made a general statement asserting that Piedmont has failed to show that its gas costs were prudently incurred. In addition, witness Buckley expressed her opinion that construction of the ACP should not be approved because the ACP is not needed, and that the Commission should disallow Piedmont's costs associated with the ACP. Further, witness Buckley requested that the Commission conduct a review of the contracts between ACP and Duke relating to the Duke utilities' subscriptions to capacity from ACP. In response to questions from the Commission, witness Buckley stated that her concerns about the ACP project are in relation to global warming and opposition to fossil fuels, and in favor of renewable fuel sources. Witness Buckley also questioned the necessity of the proposed Piedmont Robeson LNG project.

- The Public Staff Panel testified that, although the scope of Commission Rule R1-17(k) is limited to a historical review period, they also considered other information in order to anticipate the Company's requirements for future needs, including design day estimates, forecasted gas supply needs, projection of capacity additions and supply changes, and customer load profile changes.

The Public Staff Panel testified that they reviewed the testimony and exhibits of the Company's witnesses, the monthly operating reports, and the gas supply and pipeline transportation and storage contracts, as well as the Company's responses to the Public Staff's data requests. Based on this review, the Panel testified that the Company's gas costs were prudently incurred.

DISCUSSION AND CONCLUSIONS

Pursuant to N.C. Gen. Stat. § 62-133.4(e), the Commission is authorized to include all costs related to the purchase and transportation of natural gas to the natural gas local distribution company's system. Pursuant to that statute, in Docket No. G-100, Sub 58, the Commission adopted Rule R1-17(k), which includes "charges in connection with the purchase, storage or transportation of gas for the LDC's system supply" in the definition of gas costs.

Further, N.C. Gen. Stat. § 62-36.01 addresses the need to have natural gas local distribution companies enter into service agreements with interstate or intrastate pipelines to provide increased competition in North Carolina's natural gas industry. It authorizes the Commission, under certain circumstances, to order natural gas local distribution companies (LDCs) to enter into such agreements. In Docket No. G-100, Sub 91, the Commission issued an Order Requiring Reporting, which required LDCs to include information in their annual reviews concerning their future capacity needs in order to assist the Commission in carrying out its responsibilities under the statute. Although the Commission is not exercising its authority under N.C.G.S. § 62-36.01 in this docket, it recognizes that Piedmont's efforts to enter into a service agreement with ACP has the desired effect of increasing competition while reducing the risk of service interruptions.

In the prefiled questions in the Commission's Order Providing Notice of Commission Questions, and at the hearing of this matter, the Commission made inquiry into variations in projected customer demand for future periods reflected in successive Piedmont annual prudence filings. In particular, the Commission focused on changes in projected demand for the winter of 2018-2019 in the four previous annual prudence review filings by Piedmont, which reflected a decrease in projected demand of approximately 47,000 dekatherms between the Docket No. G-9, Sub 690 filing and the G-9, Sub 710 filing. Piedmont's witnesses clarified that the projected demand for this future winter period was calculated in each annual review filing using a consistently applied linear regression analysis based upon an assumed usage per heating degree day. The assumed usage per heating degree day was based on actual experience over the preceding seven year period. According to Piedmont witness Raney, the drop in projected demand for the winter 2018-2019 period was attributable to the inclusion in the look back period utilized to calculate usage per heating degree day of two relatively warm winter periods and the impacts of

Hurricane Matthew. Both Piedmont witness Raney and Public Staff witness Naba indicated that they were comfortable with Piedmont's design day calculation methodology.

In the prefiled questions attached to the Commission's Order Providing Notice of Commission Questions in this docket, and on questions from the Commission at the hearing of this matter, the issue was raised as to whether Piedmont's capacity acquisition planning and arrangements were adequate to meet customer needs in light of customer growth and changing dynamics on the interstate pipelines through which Piedmont receives upstream supplies of gas. Piedmont's written responses to the prefiled questions, as well as the testimony of Company witness Raney and the revised testimony of the Public Staff Panel, support the conclusion that Piedmont's capacity acquisition planning and arrangements are reasonable and prudent to meet projected customer demand.

In addition to its design-day demand calculation, Piedmont also utilizes a five percent (5%) reserve margin in its capacity planning and acquisition activities. In its prefiled questions, the Commission noted that, when Piedmont first proposed to use a 5% reserve margin, it used a warmer design day than other LDCs in North Carolina. The Public Staff pointed to that fact to support the addition of a 5% reserve margin, stating that, with the reserve margin, Piedmont's level of demand was equivalent to that calculated using a colder design day. In a subsequent docket, a Piedmont witness also testified in effect that the reserve margin protected against demand at a colder temperature. However, Piedmont has since significantly lowered its design-day temperature criteria. In this docket, Public Staff witness Naba testified that the Public Staff had reviewed Piedmont's use of the 5% reserve margin. She stated that the 5% reserve margin provides a cushion against higher than projected customer demand or the potential for a constraint on its upstream capacity assets on a peak day. Witness Naba noted that, historically, the Public Staff has seen a growth in Piedmont's firm customer demand and that Piedmont has a legal obligation to provide natural gas to its firm customers on the coldest day of the year. The Commission recognizes Piedmont's responsibility to stand ready to serve its customers. It also recognizes that the Public Staff represents the using and consuming public and its testimony should be given significant weight. It therefore concludes that Piedmont's capacity planning and acquisition activities are reasonable and prudent in this regard.

Piedmont's testimony (and/or written responses to Commission questions) and the Public Staff Panel's revised testimony support the fact that Piedmont has an affirmative legal obligation to maintain sufficient upstream capacity assets to serve its firm customers natural gas needs. These needs are not constant throughout the year and, accordingly, Piedmont acquires upstream capacity for baseload supply, seasonal demand during the November through March timeframe each year, and for peak day projected demand on the coldest days of the year. In order to meet its legal obligations to customers, Piedmont must ensure that these baseload, seasonal, and peak day assets exceed projected customer consumption patterns. The uncontroverted testimony in this proceeding supports the conclusion that Piedmont's capacity planning and acquisition activities taken as a whole are reasonable and prudent.

The testimony in this proceeding also demonstrates, however, that Piedmont's capacity planning has been impacted by changes in flow patterns that have occurred in recent years on the Transco pipeline. These changing flow dynamics, which include the reversal of flows in Transco's Zone 5 on occasion, have created uncertainty about the relative firmness of deliverability of supply utilizing north-to-south secondary segmented transportation rights from downstream supply sources (backhaul) on Transco. Piedmont has recently undertaken certain steps to "firm up" its capacity portfolio with respect to these supplies that were dependent on backhaul by purchasing additional primary firm North to South capacity rights on Transco in lieu of relying on secondary segmentation rights. Witness Stabley testified that firm asset management agreement contracts were used to provide for delivery to Piedmont's city gate. She also testified that agreements to firm up delivery of formally backhaul supplies is on a temporary basis, with contracts expiring in October 2019.

According to Piedmont witness Raney, the additional capacity promised by the ACP project and the proposed Robeson LNG project will also mitigate the negative impacts of changing flow dynamics on Transco. Witness Raney also testified that the vast majority of natural gas supplied to Piedmont in North Carolina currently comes off Transco, and if Transco had some serious issue, that would cause a serious issue for Piedmont.

As required in the Docket No. G-100, Sub 91 Order Requiring Reporting, Piedmont listed the FERC proceedings in which the Company participated. The Commission notes that during the review period, the Commission itself took active positions in a number of FERC dockets.

Piedmont has contracted for capacity from Transco's Eminence Storage Field (Eminence). Piedmont has not taken any position at the FERC regarding demand credits to customers where significant portions of the Eminence Storage Field are out of service. The Commission, on the other hand, has been active before the FERC on matters pertaining to Eminence.

Tomlinson Exhibit 1, Schedule 2 shows that, during the review period, Piedmont paid $2,318,429 for ESS (Eminence) Demand and Capacity, of which 85.08% or $1,972,519 was charged to North Carolina ratepayers.

In Docket No. CP11-551, Transco requested that it be allowed to abandon four of seven salt dome caverns at Eminence. After granting Transco's request to abandon the caverns at Eminence, the FERC established new operating parameters for each of the remaining three caverns. However, filings at the FERC show that Transco has been taking the remaining storage caverns out of service for extended periods for testing and maintenance, thereby raising questions as to whether it can meet the certificate parameters. Despite taking significant portions of the Eminence Storage Field out of service, Transco has not been providing demand credits to customers like Piedmont. Piedmont has not pursued demand credits, which ultimately would benefit its own North Carolina customers.

In contrast, the Commission actively pursued the question of demand credits with the FERC and, as a result, Docket No. CP18-42 was opened. Transco asserted that it operates its system on an integrated basis and, as long as it meets its contractual obligations for capacity and deliverability, it does not matter what assets it actually uses to provide those services. Piedmont filed an intervention in CP18-42, but took no position.

Following the Commission's pursuit of demand credits and the opening of the related FERC docket, Transco filed a request to reduce the certificated capacity of Eminence in Docket No. CP18-145, essentially, in the Commission's opinion, conceding that Eminence could not meet the operating parameters required by FERC in CP11-551. In effect, while Transco may have met its contractual obligations to Piedmont using undefined system assets, the Commission does not believe it was, in fact, capable of meeting full contract demand for all customers at any single point in time from Eminence. Piedmont paid for and should be assured of firm service from Transco at Eminence. The Commission has no way of knowing if Transco's undefined system assets would actually have been available on a firm basis if the system had experienced a design-day event. Accordingly, the Commission filed a protest intervention in CP18-145 based on the lack of support Transco provided for its requested certificate revisions. The Commission notes that Piedmont filed an intervention in CP18-145 on April 10, 2018, but again, took no position.

The Public Staff has recommended that the Commission find that Piedmont's gas costs were prudently incurred. The Commission agrees with and will accept that recommendation. However, the Commission remains interested in Piedmont's decisions with regard to participation in matters before the FERC. In future annual reviews, the Commission will continue to monitor and closely scrutinize the positions and actions taken by Piedmont on FERC matters, including Eminence.

The Commission appreciates witness Buckley's interest in this proceeding and her time in appearing before the Commission to testify. However, the Commission gives little weight to witness Buckley's testimony, for several reasons. First, witness Buckley provided no facts in support of her assertion that Piedmont failed to show that its gas costs were prudently incurred. Second, this Commission does not have jurisdiction over either the certification or construction of the ACP project. ACP will be an interstate natural gas pipeline which, under the provisions of the federal Natural Gas Act, is subject to the exclusive jurisdiction of the FERC. As such, concerns about the need for the project, and whether the actual capacity to be provided by the project is required by the public convenience and necessity, are matters properly addressed to the FERC, not to this Commission.

Third, with respect to witness Buckley's request that the Commission conduct an inquiry into the agreements between Duke Energy utility subsidiaries subject to this Commission's jurisdiction and ACP, the Commission notes that utility self-dealing between affiliates of Duke Energy is prohibited under statutes and the Regulatory Conditions and Code of Conduct approved by the Commission in the order approving the merger between Duke Energy and Piedmont. Order Approving Merger Subject to Regulatory Conditions and Code of Conduct, Docket Nos. E-2, Sub 1095, E-7, Sub 1100, and G-9, Sub 682 (September 29, 2016). The Commission also notes that pursuant to the Regulatory Conditions and N.C. Gen Stat. § 62-153, it has reviewed the precedent agreements between ACP and Piedmont in Docket Nos. G-9, Sub 655, E-7, Sub 1062 and E-2, Sub 1052, and has authorized Piedmont to enter into agreements for service from ACP. Finally, the Commission notes that no monies have been paid under the Piedmont precedent agreements to date and, thus, Piedmont is not seeking in this docket to recover any gas or capacity costs paid to ACP. Indeed, the Commission's orders approving the ACP precedent agreements, and amendments thereto, expressly reserve any issue of reasonable costs for resolution in subsequent proceedings. The same is and will continue to be true with regard to Piedmont's future recovery of costs associated with its Robeson LNG project.

Based on the foregoing, the Commission concludes that the Company's gas costs incurred during the review period were reasonable and prudently incurred and that the Company should be permitted to recover 100% of its prudently incurred gas costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

The evidence supporting this finding of fact is contained in the testimony of Company witness Tomlinson and the revised Public Staff Panel testimony.

Company witness Tomlinson testified that based on the Company's deferred accounts end-of-period balances, as reflected on Tomlinson Exhibit_(MBT-3) and Exhibit_(MBT-4), she recommended that the increments/decrements to Piedmont's rates be placed into effect for a period of 12 months after the effective date of the final order in this proceeding.

The Public Staff Panel testified that they had reviewed Company witness Tomlinson's proposed temporary rate increment applicable to the Sales Customers Only Deferred Account balance in Tomlinson Exhibit_(MBT-4), and the proposed temporary rate decrements applicable to the All Customers Deferred Account balance in Tomlinson Revised Exhibit_(MBT-3), and agreed that they should be implemented. The Panel also recommended that Piedmont remove all temporary rates that were implemented in Docket No. G-9, Sub 710, Piedmont's last annual review proceeding.

The Public Staff Panel further testified that Piedmont should monitor the balances in both the All Customers and Sales Customers Only Deferred Accounts, and, if needed, file an application for authority to implement new temporary increments or decrements through the Purchased Gas Adjustment mechanism in order to keep the deferred account balances at reasonable levels.

Based on the foregoing, the Commission concludes that the Company's proposed temporary rates should be implemented. In addition, the Commission concludes that it is appropriate for the Company to remove the temporary rates that were implemented in Docket No. G-9, Sub 710.

IT IS, THEREFORE, ORDERED as follows:

1. That the Company's accounting for gas costs during the 12-month period ended May 31, 2018, is approved;

2. That the gas costs incurred by Piedmont during the 12-month period ended May 31, 2018, including the Company's hedging costs, were reasonably and prudently incurred, and Piedmont is hereby authorized to recover 100% of its gas costs incurred during the review period;

3. That the Company shall remove the existing temporaries that were implemented in Docket No. G-9, Sub 710, and implement the temporary rate increment for the Sales Customers Only Deferred Account and the temporary rate decrements for the All Customers Deferred Account, as found appropriate herein, effective for service rendered on and after the first day of the month following the date of this Order;

4. That Piedmont shall give notice to its customers of the rate changes allowed in this Order; and

5. That Piedmont shall file revised tariffs within five (5) days of the date of this Order implementing the rate changes approved in Ordering Paragraph No. 3 above.

ISSUED BY ORDER OF THE COMMISSION.
This the 20th day of December, 2018.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Acting Deputy Clerk

DOCKET NO. G-5, SUB 591

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Public Service Company of North Carolina, Inc. for Annual Review of Gas Costs Pursuant to N.C.G.S. § 62-133.4(c) and Commission Rule R1-17(k)(6)	))))	ORDER ON ANNUAL REVIEW OF GAS COSTS

HEARD: Tuesday, August 14, 2018, at 10:00 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding, Commissioner Jerry C. Dockham, and Commissioner Charlotte A. Mitchell

APPEARANCES:

For Public Service Company of North Carolina, Inc.:

Andrea R. Kells, McGuireWoods LLP, 434 Fayetteville Street, Suite 2600, Raleigh, North Carolina 27601

For the Using and Consuming Public:

Gina C. Holt, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699

BY THE COMMISSION: On June 1, 2018, pursuant to N.C. Gen. Stat. § 62-133.4(c) and Commission Rule R1-17(k)(6), Public Service Company of North Carolina, Inc. (PSNC or Company), filed the direct testimony and exhibits of Candace A. Paton, Rates & Regulatory Manager for PSNC, and Rose M. Jackson, General Manager – Supply & Asset Management for

SCANA Services, Inc., in connection with the annual review of PSNC's gas costs for the 12-month period ended March 31, 2018.

On June 7, 2018, the Commission issued its Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines, and Requiring Public Notice. This Order established a hearing date of Tuesday, August 14, 2018, set prefiled testimony dates, and required the Company to give notice to its customers of the hearing on this matter.

On July 19, 2018, the Company filed Revised Jackson Exhibit 1.

On July 30, 2018, the Public Staff filed the joint testimony of Geoffrey M. Gilbert, Utilities Engineer, Natural Gas Division; Julie G. Perry, Manager of the Natural Gas Section, Accounting Division; and Sonja M. Johnson, Staff Accountant, Accounting Division.

On August 3, 2018, the Company filed its Affidavits of Publication.

On August 8, 2018, the Commission issued an Order Providing Notice of Commission Questions.

On August 14, 2018, the matter came on for hearing as scheduled, and all prefiled testimony and exhibits were admitted into evidence. No public witnesses appeared at the hearing.

On September 6, 2018, the Company filed Paton Late-filed Exhibits 2 and 3 in response to the Commission's request at the hearing.

On September 24, 2018, the Joint Proposed Order of PSNC and the Public Staff was filed.

Based on the testimony and exhibits received into evidence and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. PSNC is a corporation duly organized and existing under the laws of the State of South Carolina, having its principal office and place of business in Gastonia, North Carolina. PSNC operates a natural gas pipeline system for the transportation, distribution, and sale of natural gas to approximately 563,000 customers in the State of North Carolina.

2. PSNC is engaged in providing natural gas service to the public, is a public utility as defined in N.C. Gen. Stat. § 62-3(23), and is subject to the jurisdiction of this Commission.

3. PSNC has filed with the Commission and submitted to the Public Staff all of the information required by N.C.G.S. § 62-133.4(c) and Commission Rule R1-17(k) and has complied with the procedural requirements of such statute and rule.

4. The review period in this proceeding is the 12 months ended March 31, 2018.

5. During the review period, PSNC incurred total gas costs of $235,756,953, comprised of demand and storage charges of $91,043,579, commodity gas costs of $145,801,389, and other gas costs of ($1,088,016).

6. In compliance with the Commission's order in Docket No. G-100, Sub 67, the Company credited 75% of the net compensation from secondary market transactions, which amounted to $34,269,198, to its All Customers Deferred Account.

7. As of March 31, 2018, the Company had a debit balance (owed from the customers to the Company) of $1,443,014 in its Sales Customers Only Deferred Account and a credit balance of $13,770,526 (owed from the Company to the customers) in its All Customers Deferred Account.

8. The Company properly accounted for its gas costs incurred during the review period.

9. PSNC's hedging activities during the review period were reasonable and prudent.

10. As of March 31, 2018, the Company had a debit balance of $2,376,550 in its Hedging Deferred Account.

11. It is appropriate for the Company to transfer the $2,376,550 debit balance in the Hedging Deferred Account to its Sales Customers Only Deferred Account. The combined balance for the Hedging and Sales Customers Only Deferred Accounts is a debit balance of $3,819,564, owed by customers to the Company.

12. PSNC has adopted a gas supply policy that it refers to as a "best cost" supply strategy. This gas supply acquisition policy is based upon three primary criteria: supply security, operational flexibility, and the cost of gas.

13. PSNC has firm transportation and storage contracts with interstate pipelines, which provide for the transportation of gas to the Company's system, and both long-term and supplemental short-term supply contracts with producers, marketers, and other suppliers.

14. The gas costs incurred by PSNC during the review period were prudently incurred, and the Company should be permitted to recover 100% of such prudently incurred gas costs.

15. As proposed by PSNC witness Paton and agreed to by the Public Staff, the Company should not implement any new temporary rate changes in the instant docket at this time.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-2

These findings are essentially informational, procedural, or jurisdictional in nature and were not contested by any party. They are supported by information in the Commission's public files and records and the testimony and exhibits filed by the witnesses for PSNC and the Public Staff.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3-4

The evidence supporting these findings of fact is contained in the testimony of PSNC witnesses Jackson and Paton, and the testimony of Public Staff witnesses Gilbert and Johnson. These findings are based on N.C.G.S. § 62-133.4(c) and Commission Rule R1-17(k)(6).

Pursuant to N.C. Gen. Stat. 62-133.4, PSNC is required to submit to the Commission information and data for an historical 12-month review period, including PSNC's actual cost of gas, volumes of purchased gas, sales volumes, negotiated sales volumes, and transportation volumes. Commission Rule R1-17(k)(6)(c) requires that PSNC file weather normalization data, sales volume data, work papers, and direct testimony and exhibits supporting the information.

Witness Paton testified that Rule R1-17(k)(6) requires PSNC to submit to the Commission on or before June 1 of each year certain information with supporting work papers based on the 12-month period ending March 31. Witness Paton indicated that the Company had filed the required information. Witness Paton also stated that the Company had provided to the Commission and the Public Staff on a monthly basis the gas cost and deferred gas cost account information required by Commission Rule R1-17(k)(5)(c). Witnesses Gilbert and Johnson presented the results of their review of the gas cost information filed by PSNC in accordance with N.C.G.S. § 62-133.4(c) and Commission Rule R1-17(k)(6).

Based on the foregoing, the Commission concludes that PSNC has complied with the procedural requirements of N.C.G.S. § 62-133.4(c) and Commission Rule R1-17(k) for the 12-month review period ended March 31, 2018.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-8

The evidence supporting these findings of fact is found in the testimony and exhibits of PSNC witness Paton and the testimony of Public Staff witnesses Gilbert and Johnson.

PSNC witness Paton's exhibits show that the Company incurred total gas costs of $235,756,953 during the review period, which was comprised of demand and storage costs of $91,043,579, commodity gas costs of $145,801,389, and other gas costs of ($1,088,016). Public Staff witness Johnson confirmed that total gas costs for the review period ended March 31, 2018, were $235,756,953.

The Public Staff's testimony included a thorough analysis of PSNC's gas costs. That testimony showed that the level of demand and storage charges were down 2.4% from the level in last year's annual review in Docket No. G-5, Sub 578. The bulk of the reduction was attributed to changes in the cost of three sources of capacity. The most significant reduction was a $1,294,395 reduction in the rates paid to Cardinal Pipeline Company LLC as a result of a general rate case in Docket No. G-39, Sub 38. The costs of PSNC's capacity from Pine Needle LNG, which is regulated by the Federal Energy Regulatory Commission (FERC), decreased $780,633 as a result of a change in Pine Needle LNG's Electric Power and Fuel Tracker in FERC Docket No. RP17-576. PSNC leases 17,250 dekatherms per day (dts/day) of intrastate capacity from the City of Monroe. The contract between PSNC and Monroe called for payments to be made for a set term. The end of payments resulted in a $546,188 reduction in costs compared to the previous review period.

The Commission notes that the demand and storage costs paid by PSNC have increased in recent years as additional capacity was added to accommodate growth. In PSNC's Docket No. G-5 Sub 568, which covered a 12-month review period ending March 31, 2016, demand and storage costs rose sharply to approximately $89.3 million from $75.2 million during the previous review period. This increase was mostly attributed to the cost of adding 100,000 dts/day on Transcontinental Gas Pipe Line Company, LLC's (Transco's) Leidy Southeast project.

Public Staff witness Johnson stated that the Company recorded $45,692,268 of margin on secondary market transactions (SMT), including capacity release transactions and storage management arrangements, during the review period. Of this amount, $34,269,198 was credited to the All Customers Deferred Account for the benefit of ratepayers. She further testified that the bulk of the SMT margins, totaling $39,551,582, were produced by Asset Management Agreements.

PSNC witness Paton's prefiled testimony and exhibits reflected a Sales Customers Only Deferred Account debit balance of $1,443,014 (owed to the Company by customers) and a credit balance of $13,770,526 (owed to customers by the Company) in its All Customers Deferred Account as of March 31, 2018. Public Staff witness Johnson agreed with these balances and testified that PSNC properly accounted for its gas costs during the review period.

Based upon the foregoing, the Commission concludes that the Company properly accounted for its gas costs incurred during the review period. The Commission also concludes that the appropriate level of total gas costs incurred by PSNC for this proceeding is $235,756,953. The Commission further concludes that the appropriate balances as of March 31, 2018, are a debit balance of $1,443,014, owed to the Company, in its Sales Customers Only Deferred Account and a credit balance of $13,770,526, owed to customers, in its All Customers Deferred Account.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9-11

The evidence for these findings of fact is contained in the testimony of PSNC witnesses Paton and Jackson and the testimony of Public Staff witnesses Perry and Johnson.

PSNC witness Paton testified that the Company's Hedging Deferred Account balance for the 12-month review period ended March 31, 2018, was $2,376,550, a net debit balance, due from customers. Public Staff witness Perry testified that this balance was composed of: Economic Gains – Closed Positions of ($271,330); Premiums Paid of $2,591,190; Brokerage Fees and Commissions of $14,375; and Interest on the Hedging Deferred Account of $42,316. Public Staff witness Perry further stated that the hedging charges resulted in an annual charge of $3.15 for the average residential customer which equates to approximately $0.26 per month. Witness Perry also testified that PSNC's weighted average hedged cost of gas for the review period was $3.81 per dekatherm.

PSNC witness Jackson testified that the primary objective of PSNC's hedging program has always been to help mitigate the price volatility of natural gas for PSNC's firm sales customers at a reasonable cost. She further testified that PSNC's hedging program meets this objective by having financial instruments such as call options or futures in place to mitigate, in a cost effective manner, the impact of unexpected or adverse price fluctuations to its customers.

Witness Jackson testified that the hedging program provides protection from higher prices through the purchase of call options for up to 25% of PSNC's estimated sales volume. Witness Jackson further stated that in order to help control costs, the call options are purchased at a price no higher than 10% of the underlying commodity price. She also stated that PSNC limits its hedging to a 12-month future time period, which allows PSNC to obtain more favorable option pricing terms and better react to changing market conditions.

Witness Jackson explained that PSNC's hedging program continues to utilize two proprietary models developed by Kase and Company that assist in determining the appropriate timing and volume of hedging transactions. She stated that the total amount available to hedge is divided equally between the two models.

Witness Jackson further testified that no changes were made to PSNC's hedging program during this review period. Witness Jackson stated that PSNC will continue to analyze and evaluate its hedging program and implement changes as warranted.

Public Staff witness Perry stated that her review of the Company's hedging activities involves an ongoing analysis and evaluation of the Company's monthly hedging deferred account reports, detailed source documentation, work papers supporting the derivation of the maximum targeted hedge volumes for each month, periodic reports on the status of hedge coverage for each month, and periodic reports on the market values of the various financial instruments used by the Company to hedge. In addition, the Public Staff reviews monthly Hedging Program Status Reports, monthly reports reconciling the Hedging Program Status Report and the hedging deferred account report, minutes from the meetings of SCANA's Risk Management Committee (RMC), and minutes from the meetings of the Board of Directors and its committees that pertain to hedging activities. Further, the review includes reports and correspondence from the Company's internal and external auditors, hedging plan documents, communications with Company personnel regarding key hedging events and plan modifications under consideration by SCANA's RMC, and the testimony and exhibits of the Company's witnesses in the annual review proceeding. Witness Perry testified that based on her analysis of what was reasonably known or should have been known at the time the Company made its hedging decisions affecting the review period, as opposed to the outcome of those decisions, she concluded that the Company's hedging decisions were prudent.

Witness Perry further testified that the $2,376,550 debit balance in the Hedging Deferred Account as of the end of the review period should be transferred to the Sales Customers Only Deferred Account. Based on this recommendation, Public Staff witness Johnson stated that the appropriate balance in the Sales Customers Only Deferred Account as of March 31, 2018, after the hedging balance transfer, should be a net debit balance of $3,819,564, owed by the customers to the Company.

Based on the testimony and exhibits provided by PSNC and the Public Staff, the Commission finds that PSNC's hedging program has met the objective of contributing to the mitigation of gas price volatility and avoiding rate shock to customers. The Commission concludes that PSNC's hedging activities during the review period were reasonable and prudent and that the $2,376,550 debit balance in the Hedging Deferred Account as of the end of the review period should be transferred to the Company's Sales Customers Only Deferred Account. The Commission finds that the appropriate combined balance for the Hedging and Sales Customers Only Deferred Accounts is a debit balance of $3,819,564.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-14

The evidence for these findings of fact is found in the testimony of PSNC witness Jackson and the testimony of Public Staff witness Gilbert.

Gas Supply

PSNC witness Jackson testified that the most appropriate description of PSNC's gas supply procurement policy would be a "best cost" supply strategy, which is based on three primary criteria: supply security, operational flexibility, and cost of gas. PSNC witness Jackson stated that security of supply is the first and foremost criterion, which refers to the assurance that the supply of gas will be available when needed. Witness Jackson went on to state that supply security is obtained through PSNC's diverse portfolio of suppliers, receipt points, purchase quantity commitments, and terms. She also testified that potential suppliers are evaluated on a variety of factors, including past performance, creditworthiness, available terms, gas deliverability options, and supply location.

Witness Jackson testified that the second criterion is maintaining the necessary operational flexibility in the gas supply portfolio that will enable PSNC to react to unpredictable weather on firm sales gas usage. She noted that PSNC's gas supply portfolio must be capable of handling the monthly, daily, and hourly changes in customer demand needs. Witness Jackson also testified that operational flexibility largely results from PSNC's gas supply agreements having different purchase commitments and swing capabilities (for example, the ability to adjust purchased gas within the contract volume on either a monthly or daily basis) and from PSNC's injections into and withdrawals out of storage.

In regard to the third criterion, cost of gas, PSNC witness Jackson stated that in evaluating costs it is important to consider not only the actual commodity cost, but also any transportation-related charges such as reservation, usage, and fuel charges. She further stated that PSNC routinely requests gas supply bids from suppliers to help ensure the most cost-effective proposals. Witness Jackson further testified that in securing natural gas supply for its customers, PSNC is committed to acquiring the most cost-effective supplies while maintaining the necessary security and operational flexibility. She testified that PSNC has developed a gas supply portfolio made up of long-term agreements and supplemental short-term agreements with a variety of suppliers, including both producers and independent marketers.

Witness Jackson also testified that the majority of PSNC's interstate pipeline capacity is obtained from Transco, the only interstate pipeline with which PSNC has a direct connection. The Company also has a backhaul transportation arrangement with Transco to schedule deliveries of gas from pipelines and storage facilities downstream of PSNC's system, as well as transportation and/or storage service agreements with Dominion Energy Transmission, Inc.; Columbia Gas Transmission, LLC; Texas Gas Transmission, LLC; East Tennessee Natural Gas LLC; Dominion Energy Cove Point LNG, LP; Saltville Gas Storage Company, LLC; and Pine Needle LNG Company, LLC.

Witness Jackson further testified that PSNC engages in the following activities to lower gas costs while maintaining security of supply and delivery flexibility:

1. PSNC continues to optimize the flexibility available within its supply and capacity contracts to realize their value;

2. PSNC monitors and intervenes in matters before the FERC whose actions could impact PSNC's rates and services to its customers;

3. PSNC continues to work with its industrial customers to transport customer-acquired gas;

4. PSNC routinely communicates directly with customers, suppliers, and other industry participants, and actively monitors developments in the industry;

5. PSNC frequently has internal discussions concerning gas supply policy and major purchasing decisions;

6. PSNC utilizes deferred gas cost accounting to calculate the Company's benchmark cost of gas to provide a smoothing effect on gas price volatility; and,

7. PSNC conducts a hedging program to help mitigate price volatility.

<u>Pipeline Capacity and Storage</u>

PSNC Witness Jackson testified that in the summer of 2017 PSNC submitted a binding request for capacity on Transco's Southeastern Trail expansion project, which will provide additional firm transportation service with a receipt point at the existing Pleasant Valley Transco-Cove Point interconnection in Fairfax County, Virginia, and a delivery point at the existing Transco Station 65 pooling point in St. Helena Parish, Louisiana. In November 2017, PSNC and Transco executed a precedent agreement for this transportation service. Witness Jackson testified that the project has a target in-service date of late 2020.

Witness Jackson further noted that in previous gas cost reviews she had testified that PSNC entered into a precedent agreement with Atlantic Coast Pipeline, LLC (ACP) to acquire capacity on ACP's 550-mile pipeline project that will run from Harrison County, West Virginia, to Robeson

County, North Carolina. She provided the Commission with an update on developments concerning the status of the project and PSNC's contracting for service with ACP.

Witness Jackson also presented testimony regarding PSNC's precedent agreements with Mountain Valley Pipeline, LLC (MVP) to obtain capacity on its mainline pipeline project running from northwestern West Virginia to Pittsylvania County, Virginia, as well as on an approximately 70-mile lateral running from the termination of the mainline to delivery points at PSNC's Dan River and Haw River interconnects in Rockingham and Alamance Counties, North Carolina, respectively. The lateral project is the Mountain Valley Southgate project (MVP Southgate). Specifically, PSNC contracted for 250,000 dts/day of capacity on MVP and 300,000 dts/day on MVP Southgate. The additional 50,000 dts/day of capacity on the lateral will be used by PSNC to receive primary firm, forward-haul deliveries directly from East Tennessee through a new interconnection with MVP. Witness Jackson testified that MVP was expected be placed into service in the first quarter of 2019 and MVP Southgate would come on line in late 2020.

Witness Jackson provided testimony on the profound change that has taken place in the interstate pipeline and storage market as a result of shale gas production in the Northeast. She indicated this change has impacted the Company's gas supply security planning, requiring that additional capacity be secured to meet customer needs, particularly during periods of cold weather. She testified that:

> The Company has been able to use segmentation of the Transco firm transportation capacity and schedule backhaul deliveries of gas from Columbia Gas, Cove Point, DETI, East Tennessee/Saltville, Pine Needle, and Texas Gas - natural gas storage facilities and connecting pipelines located downstream of the PSNC system.

She distinguished "forward haul" and "backhaul":

> Forward haul involves the transportation of gas in the same direction as the physical flow of gas in the pipeline and is typically achieved when the pipeline transports gas to a delivery point downstream from the point where the gas was received by the pipeline. Backhaul involves the contractual delivery of natural gas in a direction opposite of the physical flow of gas in the pipeline; the receipt point is downstream from the point of delivery.

Witness Jackson testified that:

> PSNC's use of segmentation for backhaul deliveries on Transco can be limited because it is considered secondary firm in scheduling priority. This did not present any problems in the past, but now that gas flow on the Transco system is bidirectional in nature due to the new connected shale gas supply areas of the Northeast, PSNC has on occasion been unable to use segmentation to schedule backhaul deliveries to its city gate.

Jackson Direct Testimony, pp. 8-9.

In response to a Commission question on the reliability of backhaul to meet gas supply, witness Jackson testified that while backhaul had once been considered highly reliable and was available without any additional reservation or demand charge, PSNC has experienced supply cuts from its downstream storage facilities since Transco's Leidy Southeast and Atlantic Sunrise projects came on line with a reversal of the flow of gas on Transco's system on a primary firm basis from north to south. Witness Jackson noted these supply cuts are concerning, stating, "...we're concerned long term what type of restrictions we may see and, therefore, we have contracted for a portion of our storage withdrawal capability on the Southeastern Trail Project on Transco's system." Transcript p. 50. When asked about other efforts to mitigate the loss of backhaul as a reliable option for transporting downstream capacity, witness Jackson referenced PSNC's efforts to contract for capacity on both ACP and MVP.

In response to additional questions from the Commission, witness Jackson testified that the time horizon for getting pipeline projects on line is getting longer. She stated that if there are further delays to the pipelines' in-service dates, the Company will go to the market for "short-term capacity options." She explained that PSNC would stay in constant communication with suppliers about available capacity, either on a forward-haul or backhaul basis, and issue requests for proposal on an annual and seasonal basis. She further testified that PSNC would seek opportunities to secure bundled services for supply and transportation services delivered to PSNC's system. Additionally, witness Jackson testified that the Company looks at interstate pipelines' electronic bulletin boards and would take advantage of any opportunities to acquire existing capacity on Transco's system that might become available at a lower cost.

Part of adhering to its best cost supply strategy means PSNC must plan to have sufficient supply to serve customers' future capacity requirements on PSNC's design day, *i.e.*, the day the Company uses for planning purposes to determine the highest volume of gas it will need to meet firm customers' demand on the accepted peak coldest day that would be anticipated to be experienced in PSNC's territory. Because the Company reasonably anticipates that new customers will be added to the PSNC system going forward,[1] its design-day forecast projects customer load growth which must be accounted for in supply planning. This means adding firm pipeline and storage capacity to serve the growth in design-day needs of PSNC firm customers and to avoid a shortfall in gas supply.

Witness Jackson testified that the projected future design-day demand of PSNC's firm customers is calculated using a statistical modeling program prepared by SCANA Services Resource Planning personnel. She explained that the model assumes a 50 heating degree-day (HDD) on a 60 degree Fahrenheit base and uses historical weather to estimate peak-day demand. Witness Jackson also testified that PSNC presented its forecasted firm peak-day demand requirements for the review period and for the next five winter seasons. She further explained that the assets available to meet PSNC's firm peak-day requirements include year-round, seasonal, and

[1] PSNC is in growth mode. The Company reports an estimate of its number of customers in its annual reviews. Over the past decade, growth has averaged 10,200 customers per year. In this docket, the Company reported approximately 563,000 customers, up 13,000 from the 550,000 reported in last year's annual review.

peaking capabilities and consist of firm transportation and storage capacity on interstate pipelines as well as the peaking capability of PSNC's on-system liquefied natural gas facility.

Witness Gilbert testified that the Public Staff conducted "...an independent analysis using similar calculations to determine peak day demand levels and compare[d] that to the assets the Company ha[d] available (or [was] planning to have available when needed in the future) to meet that demand." Public Staff Direct Testimony at p. 18. The Public Staff used the review period data of customer usage and HDDs, which were calculated by taking the average of the minimum and maximum daily temperature and subtracting that quotient from 65 degrees. (For example, a low of 10 degrees and a high of 30 degrees would yield 45 HDDs.) Base load (usage that does not fluctuate with weather) plus a usage per HDD factor was developed, and the projected peak day demand was calculated. The assumption in developing a peak design-day demand was 55 HDDs (as compared to the 50 HDD on a 60 degree base used by the Company), which is the accepted peak coldest day that would be anticipated to be experienced in PSNC's territory.

Witness Gilbert testified that the results of the Public Staff's analysis were similar to the levels presented by PSNC in Revised Jackson Exhibit 1. Both witness Jackson and witness Gilbert acknowledged that their use of different HDD assumptions had not yielded a significantly different outcome for planning purposes. Witness Gilbert observed that PSNC's design-day demand models showed a shortfall of capacity beginning in the 2019 – 2020 winter season. He cited witness Jackson's testimony that in order to overcome this anticipated shortfall, PSNC has contracted for necessary capacity on ACP, which is expected to come into service by late 2019, and MVP, which is expected to have lateral facilities capable of delivering capacity to PSNC completed by late 2020.

At the hearing, with an eye toward assuring that design-day demand is not over-estimated, the Commission probed whether a reduction in demand resulting from increased efficiency should also result in a reduction in the amount of pipeline and storage capacity required on a design day. At the time the Commission approved PSNC's Customer Usage Tracker (CUT) in general rate case Docket No. G-5, Sub 495, various PSNC witnesses had testified that the CUT would more effectively support the Company's efforts to support conservation and efficiency. Among other efforts, PSNC's proposed residential and commercial high-efficiency rates were mentioned as offering a discount to customers whose dwellings and buildings comply with certain efficiency standards.

In this docket, in response to the Commission's inquiry as to whether the implementation of the CUT had impacted PSNC's design-day requirement or demand calculations, witness Jackson responded that the CUT Mechanism is not factored at all into PSNC's design-day forecast because PSNC is looking at actual throughput on the system. She reiterated that PSNC's projected design-day demand of PSNC's firm customers is calculated using a statistical modeling program prepared by SCANA Services Resource Planning personnel. Presumably, the statistical modeling program picks up efficiency improvements so that their impacts facilitated by the CUT are accounted for in PSNC's calculation of design-day demand, but are not explicitly or separately calculated.

Finally, Witness Gilbert testified regarding the prudence of PSNC's total gas costs. He testified that he had reviewed the testimony and exhibits of the Company's witnesses; monthly operating reports; gas supply and pipeline transportation and storage contracts; and the Company's responses to the Public Staff's data requests. He concluded that, in his opinion, PSNC's gas costs were prudently incurred for the 12-month review period ending March 31, 2018.

DISCUSSION AND CONCLUSIONS

Pursuant to N.C. Gen. Stat. § 62-133.4(e), the Commission is authorized to include all costs related to the purchase and transportation of natural gas to the natural gas local distribution company's system. Pursuant to that statute, in Docket No. G-100, Sub 58, the Commission adopted Rule R1-17(k), which includes "charges in connection with the purchase, storage or transportation of gas for the LDC's system supply" in the definition of gas costs.

Further, N.C. Gen. Stat. § 62-36.01 addresses the need to have natural gas local distribution companies enter into service agreements with interstate or intrastate pipelines to provide increased competition in North Carolina's natural gas industry. It authorizes the Commission, under certain circumstances, to order natural gas local distribution companies to enter into such agreements. In Docket No. G-100, Sub 91, the Commission issued Order Requiring Reporting, which required local distribution companies to include information in their annual reviews concerning their future capacity needs in order to assist the Commission in carrying out its responsibilities under that statute. Although the Commission is not exercising its authority under N.C.G.S. § 62-36.01 in this docket, it recognizes that PSNC's efforts to enter into service agreements with ACP and MVP have the desired effect of increasing competition while reducing the risk of service interruptions. As witness Jackson testified, "instead of relying on one pipeline provider, Transco, we will...in the very near future, have three pipeline providers."

PSNC witness Jackson testified that, because of the reversal of flow on Transco's system, traditional backhaul arrangements that were relied upon to get downstream pipeline and storage capacity to PSNC's system are now classified as "secondary firm" and can no longer be considered reliable. Revised Jackson Exhibit 1 shows both the forecasted firm peak-day demand requirements for the review period as well as for the next five winter seasons, and the assets available to meet those firm peak-day requirements. The Commission notes that a significant amount of capacity shown on Revised Jackson Exhibit 1 as being available to meet design-day needs, particularly seasonal and peaking storage capacity, is downstream of PSNC's system and has traditionally depended on backhaul. When PSNC first announced that it would acquire capacity on ACP, that project was scheduled to come on line in November 2018 and would have been available to firm up the delivery of that downstream capacity. Witness Jackson spoke to the actions that PSNC would now take to ensure that such downstream capacity would be available to its system on a firm basis in the near term. She also pointed to PSNC's efforts to secure more permanent, long-term capacity on Transco's Southeastern Trail, ACP and MVP/MVP Southgate.

The delays being experienced by ACP and MVP are a matter of serious concern. As mentioned above, ACP was scheduled to come on line in November 2018. In this docket, testimony was submitted that it is not going to be available until late 2019. MVP Southgate, which will both deliver gas from MVP to PSNC's system, and provide a firm path for gas from East

Tennessee/Saltville, is not expected to come on line until late 2020, which is also the in-service date for Transco's Southeastern Trail project. As discussed above, witness Jackson testified as to the steps that PSNC would take to get gas to its system on a firm basis when its customers need it. However, Revised Jackson Exhibit 1 makes clear that, if the new interstate projects are delayed, PSNC may have to go to the short-term market for considerable volumes for the next several winters. A reliance on short-term solutions raises serious questions about both their cost and their availability.

The need to firm up interstate pipeline capacity to deliver market-area storage will add significantly to demand and storage costs. As shown on Revised Jackson Exhibit 1, PSNC has contracted for 178,313 dekatherms per day of seasonal capacity. In response to a Commission question, witness Jackson stated that all of those seasonal facilities except for Saltville were depleted oil and gas reservoirs. She added that there are no depleted oil and gas reservoirs available as capacity options in North Carolina. The Commission recognizes that, to access volumes of gas on a seasonal basis, it might be necessary both to maintain existing contracts to what had been market-area seasonal storage and to secure year-round pipeline capacity to move the stored gas to PSNC's city gate. However, the Commission expects PSNC to consider all possibilities as part of its best cost approach to gas supply.

In witness Jackson's description of the Company's actions taken to accommodate its best-cost policy, she listed "Monitor and intervene in matters before the FERC whose actions could impact the rates that PSNC pays and the services it receives from interstate pipelines and storage facilities." Jackson Direct Testimony at p. 15. As required in the Docket No. G-100, Sub 91 Order Requiring Reporting, PSNC listed the FERC proceedings in which the Company participated. In sixteen of the seventeen proceedings listed in Jackson Exhibit 3, PSNC had done nothing more than file a petition to intervene. No position was taken. The Commission notes that during the time period over which PSNC took the reported actions at the FERC, the Commission itself took active positions in a number of FERC dockets.

For example, at the hearing in this docket, the Commission asked both the Public Staff and Company witnesses about Transco's Eminence Storage Field (Eminence). PSNC has not taken any position at the FERC regarding demand credits to customers where significant portions of the Eminence Storage Field are out of service. The Commission, on the other hand, has been active before the FERC on matters pertaining to Eminence.

To further explain, PSNC has contracted for capacity from Eminence under two contracts. Paton Exhibit 1, Schedule 2 shows that, during the review period, PSNC paid $938,594 for ESS Demand and Capacity and $954,471 for Eminence Demand and Capacity. Witness Jackson testified that a few years ago, PSNC contracted with Transco for additional withdrawal and injection capacity, which explains the two different contracts. She further testified that PSNC had "...not encountered any interruptions in our service so that's why we continue to contract for that storage service." Transcript, p. 76.

In Docket No. CP11-551, Transco requested that it be allowed to abandon four of seven salt dome caverns at Eminence. After granting Transco's request to abandon the caverns at Eminence, the FERC established new operating parameters for each of the remaining three caverns. However, filings at the FERC show that Transco has been taking the remaining storage caverns out of service for extended periods for testing and maintenance, thereby raising questions as to whether it can meet the certificate parameters. Despite taking significant portions of the Eminence Storage Field out of service, Transco has not been providing demand credits to customers like PSNC. PSNC has not pursued demand credits, which ultimately would benefit its own North Carolina customers.

In contrast, the Commission actively pursued the question of demand credits with the FERC and, as a result, Docket No. CP18-42 was opened. Transco asserted that it operates its system on an integrated basis and, as long as it meets its contractual obligations for capacity and deliverability, it does not matter what assets it actually uses to provide those services. PSNC filed an intervention in CP18-42, but took no position.

Following the Commission's pursuit of demand credits and the opening of the related FERC docket, Transco filed a request to reduce the certificated capacity of Eminence in Docket No. CP18-145, essentially, in the Commission's opinion, conceding that Eminence could not meet the operating parameters required by FERC in CP11-551. In effect, while Transco may have met its contractual obligations to PSNC using undefined system assets, the Commission does not believe it was, in fact, capable of meeting full contract demand for all customers at any single point in time from Eminence. PSNC paid for and should be assured of firm service from Transco at Eminence. The Commission has no way of knowing if Transco's undefined system assets would actually have been available on a firm basis if the system had experienced a design-day event. Accordingly, the Commission filed a protest intervention in CP18-145 based on the lack of support Transco provided for its requested certificate revisions. PSNC filed an intervention in CP18-145, but again, took no position.

The Public Staff has recommended that the Commission find that PSNC's gas costs were prudently incurred. The Commission agrees with and will accept that recommendation. However, the Commission remains interested in PSNC's decisions with regard to participation in matters before the FERC. In future annual reviews, the Commission will continue to monitor and closely scrutinize the positions and actions taken by PSNC on FERC matters, including Eminence.

Based upon the foregoing, the Commission concludes that the Company's gas costs incurred during the review period ended March 31, 2018, were reasonable and prudently incurred and that the Company should be permitted to recover 100% of its prudently incurred gas costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence for this finding of fact is found in the testimony of PSNC witness Paton and the testimony of Public Staff witness Gilbert.

Witness Paton testified that the Company was not proposing new temporary rate increments or decrements at this time. Specifically, PSNC witness Paton testified that the Company proposes to leave the current temporary decrements applicable to the All Customers Deferred Account in place and monitor the balance in the account to determine when or if changes are required. She stated that the Company proposes to continue its practice of taking into consideration the balance in the Sales Customers Only Deferred Account when evaluating whether to file for a change in the benchmark cost of gas. She concluded that the Company believes that making periodic and smaller adjustments in the benchmark cost of gas is preferable to making one adjustment annually based on the over- or under-collection in commodity cost of gas that may exist as of the end of the review period.

Witness Gilbert testified that the All Customers Deferred Account reflects a credit balance of $13,770,526 owed by the Company to customers. He noted that PSNC has proposed not to place a decrement in rates for the adjustment of this credit balance. At the end of May, the over-collection had decreased to $9,145,536, and the Company estimates the balance will "flip" to an under-collection of approximately $8.4 million by the end of October 2018. The Sales Customers Only Deferred Account reflects an under-collection of $1,443,014, owed by customers to the Company. The current tariff rates, which were approved in the Company's Purchased Gas Adjustment (PGA) filing in Docket No. G-5, Sub 583 and became effective January 1, 2018, are based on an over-collection of approximately $15.0 million in the All Customers Deferred Account. Witness Gilbert concluded that removing the decrements that are currently in place and implementing a new rate based on the $13,770,526 credit balance in the All Customers Deferred Account would not be beneficial to the rate payers. He noted that it is not unusual to have a change in the balances, since fixed gas costs are typically over-collected during the winter period when throughput is higher due to heating load, and under-collected during the summer when throughput is lower. He agreed with the Company's proposal to leave the current temporary decrements applicable to the All Customers Deferred Account in place and monitor the balance in the account to determine when or if changes are required. He recommended that PSNC continue to monitor the balances in both the All Customers and the Sales Customers Only Deferred Accounts and file for a request to implement new temporary increments or decrements, as applicable, through the PGA mechanism to avoid significant over-collections of its fixed gas costs. He agreed with PSNC's proposal of not taking any action on the All Customers and the Sales Customers Only Deferred Accounts at this time.

In addition to not changing the temporary decrements that PSNC currently has in place, witness Gilbert also agreed with PSNC's proposal not to place a decrement in rates for the recovery of this credit balance, but to manage it by using the PGA mechanism, pursuant to N.C.G S. § 62-133.4, which PSNC has previously used for this purpose. He concluded that requiring PSNC to implement temporary rate changes in the instant docket at this time would not be productive, and, therefore, he agreed with the Company's proposals. The Commission notes that PSNC's Summary of Deferred Gas Cost Accounts for the month of August that was filed on October 15, 2018 in Docket No. G-5, Sub 586 reported a debit balance of $2,020,888 in the All Customers Deferred Account.

Based on the testimony discussed above, the Commission notes that it is commonplace for the Company to over-collect its fixed gas costs during the winter months and under-collect during summer months and recognizes that this is what occurred during the prior review period ended March 31, 2017, in Docket No. G-5, Sub 578. Had the Commission ordered a rate decrement in that proceeding, the effect would have been counterproductive, due to the fact that by the time temporary decrements would have gone into effect in November 2017, the Company's All Customer Deferred Account was under-collected, and it would have had to file a petition to remove the decrement and perhaps implement an increment.

The Commission concludes that the same would be true in this docket. If the Commission were to require decrements, by the time rates go into effect in November the Company would likely be under-collected and the decrements would exacerbate that position. Based on the facts in the present docket, and the record as a whole, the Commission finds and concludes that it is appropriate not to require PSNC to implement new temporary rate decrements in the instant docket at this time. However, the Commission expects PSNC to continue to monitor market conditions and the Sales Only Customer Deferred Account balances and, if necessary, to file a PGA to make an appropriate adjustment to rates.

IT IS, THEREFORE, ORDERED as follows:

1. That PSNC's accounting for gas costs for the 12-month period ended March 31, 2018, is approved;

2. That the gas costs incurred by PSNC during the 12-month period ended March 31, 2018, including the Company's hedging costs, were reasonably and prudently incurred, and PSNC is hereby authorized to recover 100% of these gas costs as provided herein; and

3. That as proposed by PSNC and agreed to by the Public Staff in the instant docket, PSNC shall not implement any temporary rate changes effective for service rendered on and after December 1, 2018.

ISSUED BY ORDER OF THE COMMISSION
This the 6th day of December, 2018

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. G-40, SUB 145

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Frontier Natural Gas Company for Annual Review of Gas Costs Pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6)	))))	ORDER ON ANNUAL REVIEW OF GAS COSTS

HEARD: Tuesday, March 6, 2018, at 10:00 a.m., in the Commission Hearing Room 2160, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding; and Commissioners Lyons Gray and Charlotte A. Mitchell

APPEARANCES:

For Frontier Natural Gas Company:

James H. Jeffries IV, McGuireWoods, LLP, 201 N. Tryon Street, Suite 3000, Charlotte, North Carolina 28202

For the Using and Consuming Public:

Elizabeth D. Culpepper, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On December 1, 2017, pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6), Frontier Natural Gas Company (Frontier or Company) filed the direct testimony and exhibits of Fred A. Steele, President/General Manager, in connection with the annual review of Frontier's gas costs for the 12-month period ended September 30, 2017.

On December 6, 2017, the Commission issued its Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines and Requiring Public Notice. The Order set the annual review of the Company's gas costs for hearing on March 6, 2018, set pre-filed testimony dates, and required Frontier to give notice of the hearing.

On February 15, 2018, the Public Staff – North Carolina Utilities Commission (Public Staff) filed a motion requesting that the Commission extend the date for the Public Staff to file its testimony to February 22, 2018, and the date for Frontier to file its rebuttal to March 2, 2018. The Commission granted the extension of time by order dated February 16, 2018.

On February 22, 2018, the Public Staff filed the joint direct testimony and exhibits of Jan A. Larsen, Director, Natural Gas Division; Shawn L. Dorgan, Staff Accountant, Accounting Division; and Julie G. Perry, Accounting Manager, Natural Gas & Transportation Section, Accounting Division (Public Staff Panel). On February 27, 2018, the Public Staff filed revised Pages 9, 10, and 22 to its pre-filed testimony.

On March 1, 2018, Frontier filed the rebuttal testimony of Company witness Steele and its Affidavits of Publication of Public Notice of Hearing.

No other party intervened in this docket.

On March 1, 2018, Frontier and the Public Staff filed a joint motion for witnesses to be excused from appearance at the hearing and requested that the pre-filed testimony and exhibits of all witnesses be received into the record without requiring the appearance of any such witnesses, which was granted by the Commission on March 2, 2018.

On March 6, 2018, the matter came on for hearing as scheduled, and all pre-filed testimony and exhibits were admitted into evidence. No public witnesses appeared at the hearing. In accordance with the March 2 Order, no expert witnesses took the stand or provided testimony at the hearing and all pre-filed testimony and exhibits were received and stipulated into the record.[1]

In compliance with the requirements of Chapter 138A of the North Carolina Government Ethics Act, each member of the Commission panel has made a due and diligent effort to determine whether he or she has a conflict of interest in the matter presented in this docket, and each member of the panel has determined that he or she does not have any such conflict.

On April 5, 2018, the Joint Proposed Order of Frontier and the Public Staff was filed.

Based upon the testimony and exhibits received into evidence and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. Frontier is a public utility as defined by G.S. 62-3(23), organized and existing under the laws of the State of North Carolina with its headquarters in Elkin, North Carolina.

2. Frontier is a natural gas local distribution company (LDC), primarily engaged in the business of purchasing, transporting, distributing, and selling natural gas to approximately 3,600 customers in North Carolina, as of September 30, 2017.

3. Frontier has filed with the Commission and submitted to the Public Staff all of the information required by G.S. 62-133.4(c) and Commission Rule R1-17(k) and has complied with the procedural requirements of such statute and rule.

[1] Presiding Commissioner Brown-Bland and Commissioner Gray did not appear at the hearing on March 6, 2018, due to another hearing which continued beyond the time it had been expected to conclude. For this reason, Commissioner Mitchell presided on March 6 to receive the evidence in accordance with the Commission's March 2, 2018 Order. At the hearing, the parties stipulated they did not object to Commissioners Brown-Bland's and Gray's continued participation as panel members in this docket notwithstanding their being unable to attend the March 6 hearing, where only testimony and exhibits as pre-filed were received into evidence.

4. The review period in this proceeding is the 12-months ended September 30, 2017.

5. During the review period, Frontier incurred total gas costs of $4,699,507, which was comprised of pipeline demand charges of $1,090,560, gas supply costs of $3,700,261, and other gas costs of ($91,314).

6. The appropriate Deferred Gas Cost Account balance at September 30, 2017, is a debit balance of $251,005, owed by Frontier's customers to the Company.

7. It is reasonable to include an adjustment of $98,159, including interest, for the proration of Frontier's Benchmark City Gate Delivered Gas Cost (Benchmark) in the calculation of its gas cost collections during the current review period.

8. Frontier properly accounted for its gas costs during the review period.

9. Frontier did not hedge during the current review period.

10. Frontier's decision not to engage in financial hedging transactions during the review period was reasonable and prudent.

11. During the review period, Frontier purchased all of its gas supply requirements from a full requirements gas supplier, with the exception of transportation imbalance cash-outs.

12. Frontier utilized pipeline capacity from Transcontinental Gas Pipe Line Company, LLC (Transco), and acquired additional year round pipeline capacity on Transco during this review period.

13. Frontier has continued its "best evaluated cost" gas purchasing supply strategy policy.

14. The gas costs incurred by Frontier during the review period were prudently incurred, and Frontier should be permitted to recover 100% of its prudently incurred gas costs.

15. Frontier should not be required to implement a rate increment in this docket.

16. The appropriate interest rate to be used to calculate interest on Frontier's deferred gas cost account should be 6.60%, effective January 1, 2018.

17. Frontier should file its annual review schedules in such a manner that they present a summary of its gas costs that agree with Frontier's monthly deferred account reports in future annual review proceedings.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-2

These findings are essentially informational, procedural, or jurisdictional and are based on evidence uncontested by any of the parties. The evidence supporting these findings is contained in the official files and records of the Commission, the testimony and exhibits of Company witness Steele, and the testimony of the Public Staff Panel.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3-4

The evidence supporting these findings is contained in the testimony of Frontier witness Steele, the testimony of the Public Staff Panel, and the provisions of G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

G.S. 62-133.4 requires that each natural gas utility submit to the Commission information and data for an historical 12-month review period concerning its actual cost of gas, volumes of purchased gas, sales volumes, negotiated sales volumes, and transportation volumes. Commission Rule R1-17(k)(6)(c) requires the filing of work papers, direct testimony, and exhibits supporting the information.

Frontier witness Steele testified that the Company is responsible for and has complied with reporting gas costs and deferred account activity to the Commission and the Public Staff on a monthly basis as required by Commission Rule R1-17(k). The Public Staff Panel confirmed that the Public Staff has reviewed the reports filed by Frontier. The Commission, therefore, concludes that Frontier has complied with all of the procedural requirements of G.S. 62-133.4(c) and Commission Rule R1-17(k) for the review period.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-8

The evidence supporting these findings of fact is contained in the testimony and exhibits of Frontier witness Steele and the testimony of the Public Staff Panel.

Company Schedule 1 reflected that Frontier's total gas costs for the review period were $4,804,228. Public Staff witness Dorgan testified that Frontier's total gas costs for the current review period per the Company's monthly deferred account reports filed with the Commission were $4,641,053, as compared to the prior year of $5,242,868. Witness Dorgan testified that in the current review period, in order to reconcile the cost of gas to the GS-1 Reports filed with the Commission, the Company reflected the offsetting gas cost true-up entries of $149,768 as well as entries that are recorded in other cost of gas but do not impact the Company's deferred account of $58,454, resulting in a total cost of gas for the current review period of $4,699,507.

The Public Staff Panel testified that the Public Staff reviewed the testimony and exhibits of Company witness Steele, the Company's monthly Deferred Gas Cost Account reports, monthly financial and operating reports, the gas supply and transportation contracts, and the Company's responses to Public Staff data requests. The Public Staff Panel also testified it reviewed Frontier's responses to the Public Staff data requests which contained information related to Frontier's gas purchasing and hedging philosophies, key customer metrics, gas portfolio mixes, long-term contracts entered into for the purchase of additional pipeline capacity, and reconciliations of capacity versus commodity cost of gas charges.

Company witness Steele testified that Frontier's Deferred Gas Cost Account had an ending debit balance at September 30, 2017, of $262,677 owed to Frontier from customers, as shown on Company Schedule 8.

Public Staff witness Perry cited Ordering Paragraph 4 of the Commission's Order on Annual Review of Gas Costs issued on August 23, 2016, in Docket No. G-40, Sub 130 (2015 Annual Review Order), that required Frontier to "begin prorating its Benchmark cost of gas in the calculation of its gas cost collections from customers in a manner consistent with how Frontier prorates customers' bills." She explained that in accordance with the 2015 Annual Review Order, Frontier started prorating its Benchmark cost of gas rate changes in its deferred account during the 2015-2016 annual review period. Witness Perry noted that during the present review period, in Docket No. G-40, Subs 137 and 141, Frontier filed to change its Benchmark cost of gas effective February 1, 2017, and August 1, 2017, respectively. Witness Perry testified that based on the template that Frontier and the Public Staff previously agreed that the Company would use (in compliance with Ordering Paragraph 6 of the 2015 Annual Review Order), Frontier filed its February and August 2017 monthly deferred account reports with proration adjustments. Prior to the filing of Frontier's annual gas costs, the Company informed the Public Staff that they had a potential issue with the proration adjustments filed during the review period that impacted Frontier's annual review filing. The Company subsequently provided supporting calculations for the Public Staff's review related to the proposed adjustments.

Public Staff witness Perry testified that once the Public Staff was able to review the Company's proposed proration adjustment, as well as similar calculations of other LDCs, the Public Staff determined that the proration adjustment needed to be revised to reflect the actual unbilled volumes as compared to the estimated unbilled volumes when prorating a benchmark change. Based on the volume and revenue billing data provided by Frontier, witness Perry testified that the proration adjustment correction should be a debit entry of $98,159, including interest, instead of the $104,724 as proposed by Frontier, which is shown on Public Staff Panel Exhibit II. Witness Perry recommended that witness Dorgan update the Company's deferred account balance as of September 30, 2017, for this adjustment.

Public Staff witness Dorgan testified that based on (1) his review of the gas costs in this proceeding, (2) witness Perry's recommended proration adjustment to the deferred gas cost account, and (3) witness Larsen's opinion that the Company's gas costs were prudently incurred – that the appropriate balance in Frontier's Deferred Gas Cost Account at September 30, 2017, is a $251,005[1] debit balance, owed to Frontier from customers. Witness Dorgan further testifed that the activity consisted of a beginning balance of ($7,899), a commodity gas cost true-up of $249,206, commodity true-up adjustments of ($71,406), transportation customer balancing true-up of ($33,169), transportation customer balancing true-up adjustment of $5,150, a Transco refund of ($15), accrued interest of $10,982, and a rounding adjustment of ($4). Winess Dorgan testified that the balance also included a Public Staff adjustment to the benchmark proration of $98,159, including interest.

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[1] Due to rounding of the numbers on the Public Staff Joint Testimony, page 20, the Public Staff Recommended Deferred Account Balance totals $251,005 instead of $251,004.

Company witness Steele filed rebuttal testimony, in which he testified that Frontier agreed with the Public Staff's proration adjustment.

Based on the foregoing, the Commission concludes that Frontier has properly accounted for its gas costs incurred during the review period. The Commission further concludes that the Public Staff's proration adjustment, with interest, as well as the debit Deferred Gas Cost Account balance of $251,005, owed from customers to Frontier, are appropriate and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9-10

The evidence for these findings of fact is contained in the testimony and exhibits of Company witness Steele and the testimony of Public Staff witness Perry.

Company witness Steele testified that the Company continually monitors the NYMEX natural gas commodity market and associated hedging developments, trends, activity and costs. Witness Steele further testified that Frontier did not engage in hedging activity during the current review period of October 2016 to September 2017.

Public Staff witness Perry testified that Frontier's hedging program is an integral part of an overall gas purchasing strategy that attempts to establish price stability, utilize cost efficient purchasing, and reduce the risk of price increases to customers. Witness Perry testified that Frontier uses a weighted average, three-part approach in purchasing its physical gas supplies: first-of-the-month baseload; hedging; and daily swing. Furthermore, Public Staff witness Perry testified that a core part of Frontier's strategy is to obtain reliability and price stability by fixing components of its gas costs, primarily commodity costs, through hedging.

Public Staff witness Perry further testified that the primary difference in Frontier's hedging approach compared to other LDCs is that Frontier uses physical hedges exclusively and does not use financial hedges, such as options, futures, or swaps, which are typically used by the other North Carolina LDCs. Witness Perry explained that a physical hedge is a fixed price contract between two parties to buy or sell physical natural gas supplies at a certain future time, at a specific price, which is agreed upon at the time the deal is executed. She testified that Frontier's gas supply portfolio includes the physical purchase of fixed price gas supplies for delivery at its city gate on a monthly basis.

With respect to the company's hedging activities during the review period, Public Staff witness Perry cited witness Steele's pre-filed testimony as follows:

Q. Did Frontier investigate hedging during the test year and, if so, what were the findings and conclusions?

A. Frontier continually monitors the NYMEX natural gas commodity market and associated hedging developments, trends, activity and costs. Frontier did not engage in hedging activity during the current review period of October 2016 to September 2017. Additionally, Frontier evaluated a peak day proposal from UGI.

Witness Perry also explained that in response to a Public Staff data request, the Company explained that "Frontier has determined not to utilize a physical hedge for any natural gas for the winter 2016-2017 because of its ability to purchase almost 70% of our gas supply needs at Zone 3 FOM [First of Month] prices as opposed to Zone 5 FOM prices."

Public Staff witness Perry testified that Frontier's decision not to hedge during the review period appears to have been influenced by the fact that Frontier had sufficient physical gas purchases to serve its market during the review period rather than implementing hedges in an effort to mitigate price spikes to customers.

Public Staff witness Perry further testified that while the Commission's prior hedging orders do not differentiate between financial hedges and physical hedges, the other LDCs in North Carolina all have the ability to purchase 100% of their gas supply needs at FOM prices as opposed to Zone 5 FOM prices, yet all the other LDCs are consistently hedging to avoid the risk of price spikes to the utilities' customers. Witness Perry testified that she believes Frontier's customers are similarly at risk of unforeseen price spikes in gas prices.

Witness Perry concluded from her analysis, based on what was reasonably known or should have been known at the time the Company made its hedging decisions affecting the review period, as opposed to the outcome of those decisions, that the Company's hedging decisions were prudent. However, the Public Staff recommended that the Commission remind Frontier that the purpose of hedging is to reduce price spikes to customers, not just to secure gas supply, and put Frontier on notice that the risk is on Frontier, not its ratepayers, if price spikes occur and no hedging strategies are in place in the future.

Based on the foregoing, the Commission concludes that Frontier's hedging activities during the review period were reasonable and prudent. However the Commission takes notice that its prior hedging orders provide the appropriate standard for the review of hedging decisions by LDCs and recognize that the purpose of hedging is to reduce the volatility of commodity costs. The Commission also notes that an LDC's decisions with respect to mitigation of the effects of price spikes will be subject to review in the LDC's annual gas cost prudency review proceeding and that includes both decisions to hedge and not to hedge. In addition, the Commission reiterates to Frontier that it should address its hedging policy and program in its testimony in each annual gas cost prudency review, explaining why and how it hedged or why it did not hedge during the test period.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11-14

The evidence for these findings of fact is contained in the testimony of Company witness Steele and the testimony of Public Staff witnesses Larsen.

Company witness Steele testified that the Company's gas supply policy is best described as a "best evaluated costs" supply strategy. This strategy is based upon the following criteria: flexibility, security/creditworthiness, reliability of supply, the cost of the gas, and the quality of supplier customer service.

NATURAL GAS – MISCELLANEOUS

Company witness Steele testified that security of gas supply is required because of the daily changes in Frontier's market requirements caused by the unpredictable nature of weather, the production levels/operating schedules of Frontier's industrial customers, the industrial customers' option to switch to alternative fuels, and customer growth during the test period. He noted that while Frontier's gas supply agreements have different purchase commitments and swing capabilities (i.e., the ability to adjust purchase volumes within the contract volume), the gas supply portfolio as a whole must be capable of handling the seasonal, monthly, daily, and hourly changes in Frontier's market requirements.

Company witness Steele testified that Frontier understands the necessity of having security of supply to provide reliable and dependable natural gas service and has demonstrated its ability to do so. He testified that Frontier's gas supply strategy and its contracts implementing this strategy have allowed Frontier to accomplish this objective.

Company witness Steele testified that the Company continues to incorporate a three-part pricing strategy to help establish price stability and obtain the optimum opportunity in savings: hedging, first of the month index purchases, and daily purchases. He also observed that Frontier will adjust the weights of each component and incorporate the best pricing methodology to obtain the optimum opportunity in savings and price stability. Company witness Steele further testified that the goal of the weighted average approach is to take advantage of any market movements in pricing that may occur as a proactive measure and/or savings opportunity.

Company witness Steele testified that in January 2016, Frontier issued requests for proposals to four potential natural gas suppliers, including Frontier's supplier at that time. Company witness Steele explained that three companies responded with proposals for Frontier's consideration, and Frontier evaluated the proposals using the criteria of their best evaluated gas supply strategy. Company witness Steele observed that in March 2016, Frontier selected UGI Energy Services, LLC (UGI) to provide its gas supply needs for the next 12-months, based on their ability to satisfy these criteria and UGI began working as Frontier's new asset manager starting April 1, 2016. Finally, Company witness Steele testified that on March 31, 2017, Frontier exercised an option for the renewal of its contract with UGI until March 31, 2020.

Public Staff witness Larsen testified that during the review period of October 1, 2016, through September 30, 2017, Frontier experienced customer growth of 7.48%, which is very similar to the prior year growth rate of 7.39%. Company witness Steele cited a similar customer growth rate of 8.3%, from the period October 31, 2016, to October 31, 2017. Public Staff witness Larsen also testified that there was a slight decrease in both Frontier's sales and transportation volumes from the prior review period. Witness Larsen concluded that since Frontier's winter throughput is largely dependent on weather due to space heating load, the volume change is correspondingly affected by a change in Heating Degree Days (HDDs) as compared to the prior period.

Public Staff witness Larsen testified that Frontier acquired an additional 2,663 dekatherms (dts) per day of Transco year round pipeline capacity effective January 2017, which results in a total pipeline capacity for Frontier of 8,613 dts per day for the current review period. Company witness Steele testified that Frontier will continue to seek incremental pipeline capacity and evaluate storage opportunities in order to serve its customers. Public Staff witness Larsen testified that in a data request response, Frontier testified that it reached out to gas companies and municipalities in order to partner to obtain additional capacity on Transco and that Frontier did not encounter any storage opportunities.

Public Staff witness Larsen's testimony cited Ordering Paragraph 6 of the Commission's Order on Annual Review of Gas Costs issued on June 13, 2017, in Docket No. G-40, Sub 135 (2016 Annual Review Order) which required: "[t]hat before the filing of Frontier's next annual review proceeding, Frontier shall have a study performed, similar to the consultant report attached to Company witness Steele's testimony as Exhibit FAS-1, discussing, among other things, peak day forecasts and determination of contract demand policy, and make it available to the Public Staff for its review."

Public Staff witness Larsen testified that attached to Company witness Steele's testimony as CONFIDENTIAL Exhibit B was a report on Design Day Study prepared by Dr. Ronald H. Brown, PhD, who utilized the Marquette University GasDay program in evaluating Frontier's projected peak day demand. Public Staff witness Larsen testified that he had evaluated the report and concluded that it complies with the 2016 Annual Review Order and accurately calculates Frontier's peak day using reasonable assumptions, such as HDDs and frequency of occurrence of such cold weather events. Public Staff witness Larsen concluded that based on the report, it appears that Frontier has adequate capacity in order to serve its firm market on peak days until the 2021-2022 winter period.

Based upon the Public Staff's investigation and review of the data filed in this docket, and the adjustment to Frontier's deferred gas cost account, witness Larsen testified that Frontier's gas costs during the review period were prudently incurred.

Based on the foregoing, the Commission concludes that the Company's gas costs incurred during the review period were reasonable and prudently incurred and that the Company should be permitted to recover 100% of its prudently incurred gas costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence for this finding of fact is contained in the testimony and exhibits of Company witness Steele and the testimony of the Public Staff Panel.

Company witness Steele testified that Frontier anticipated that the current deferred account balance will be moving back toward $0.00 over the winter months. Public Staff witness Larsen noted that Frontier did not propose any temporaries in this proceeding and further testified that Public Staff witness Dorgan determined the appropriate deferred account balance owed from customers to Frontier is a debit balance of $251,005. Public Staff witness Larsen testified that normally the Public Staff would recommend a temporary rate increment in order to collect this debit balance from customers, but that the Panel's investigation led them to conclude that Frontier's deferred account has changed significantly since the end of the review period. Consequently, Public Staff witness Larsen recommended that Frontier file for a Purchased Gas Adjustment (PGA) in mid-March for an effective date of April 1, 2018. Finally, witness Larsen testified that he believed this course of action would more quickly and accurately resolve the under-collection of gas costs and would take effect April 1, 2018, which he testified is two or more months earlier than an order would typically be issued in Frontier's annual review proceeding. Public Staff witness Larsen testified that he does not recommend any temporary rate increments or decrements at this time.

The Commission agrees with the recommendation of Public Staff witness Larsen and concludes that it is not appropriate to require Frontier to implement a temporary rate increment at this time. The Commission also takes judicial notice that on March 16, 2018, in Docket No. G-40, Sub 147, Frontier filed a PGA to increase its benchmark from $4.00 per dt to $6.00 per dt, an increase of by $2.00 per dt. On March 27, 2018, the Commission issued an Order Approving Rate Changes effective April 1, 2018.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence for this finding of fact is contained in the testimony and exhibits of Company witness Steele and the testimony of Public Staff witness Perry.

Public Staff witness Perry testified that in Docket No. G-40, Sub 135, Frontier's prior annual review of gas costs proceeding, the Public Staff recommended and the Commission approved in its Order on Annual Review of Gas Costs issued June 13, 2017, that Frontier should begin calculating interest on its deferred account using the net-of-tax overall rate of return approved by the Commission in its Order Approving Use of Natural Gas Bond Funds issued March 12, 2000, in Docket No. G-40, Sub 2, adjusted for any known corporate income tax rate changes, as the applicable interest rate on all amounts over-collected or under-collected from customers reflected in its Deferred Gas Cost Account.

Witness Perry further testified that in 2017 the Public Staff investigated a merger application filed by Frontier in November 2016 (Docket No. G-40, Sub 136), which caused the Public Staff to further evaluate the appropriate determinants to be used to calculate the earnings of Frontier in order to determine a reasonable overall rate of return applicable to Frontier. She explained that this review included the capital structure, debt cost from Frontier's most recent financing docket (Docket No. G-40, Sub 133), and a reasonable return on equity.

Witness Perry also noted that the 2017 Federal Tax Cuts and Jobs Act has reduced the corporate federal income tax rate from 35% to 21%, effective January 1, 2018.

Public Staff witness Perry testified that in light of the foregoing, the Public Staff recommended that Frontier begin using 6.50% as the interest rate on the deferred gas cost account effective January 1, 2018, as shown on Public Staff Panel Exhibit III.

Company witness Steele testified in rebuttal testimony that after discussions with the Public Staff, both parties had agreed to 6.60% as the interest rate on the deferred gas cost account effective January 1, 2018.

The Commission concludes that 6.60% is the appropriate interest rate to use in the deferred gas cost account effective January 1, 2018.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

The evidence for this finding of fact is contained in the testimony and exhibits of Company witness Steele and the testimony of Public Staff witness Perry.

Public Staff witness Perry testified that she was concerned that the amounts contained in the Company's filed annual review exhibits do not match the monthly deferred account reports filed with the Commission due to (1) the Company inserting proposed proration adjustments into the annual review exhibits that had not been filed with the Commission in the monthly deferred account reports for those months, and (2) the Company reclassifying demand and commodity charges reflected in the annual review exhibits, which do not correlate to charges reflected in the monthly deferred account reports and the invoices reviewed by the Public Staff.

Witness Perry testified that typically, if an LDC believes that a proposed adjustment is warranted, the adjustment is noted in testimony and possibly on Schedule 8 – Deferred Account with a footnote, but the LDC does not restate the total gas costs for the review period. She explained that the Public Staff's review procedures include tracing the Company's filed annual review exhibits to the monthly deferred account filings made each month during the review period. She further noted that another review procedure attempts to compare for agreement the total cost of gas reflected on Schedule 1 to the cost of gas reflected in the monthly financial statements. Witness Perry testified that by the Company inserting the proposed adjustments and restating Schedules 1 and 4, not only do the deferred account entries not agree to the filed deferred account reports, but Frontier's filed total cost of gas does not agree to the GS-1 Reports or the monthly financial reports filed by Frontier with the Public Staff and the Commission.

Public Staff witness Perry testified that she had a second issue related to Frontier's reclassifications of demand and commodity charges in the annual review exhibits as compared to the monthly deferred account reports. She explained that although the total demand and commodity charges reported in the annual review exhibits do agree to the filed monthly deferred account reports, the reclassification of the types of charges reflected in the annual review makes it virtually impossible for the Public Staff to trace specific charges into the monthly deferred account filings. She further explained that the Public Staff had a similar issue in Frontier's prior annual review of gas costs proceeding and recorded the unreconciled amounts in other supply costs. Witness Perry testified that for the current review period, the Public Staff has presented the demand and commodity charges in the Public Staff's testimony exactly as these charges were reflected on the invoices supporting the monthly deferred account entries that it audited. Witness Perry noted that the Public Staff reflected the Other Gas Costs just as these amounts were filed by the Company in the monthly deferred account filings along with entries that are recorded in other cost of gas but do not impact the Company's deferred account. She noted that in addition, the Public Staff excluded the Company's proposed proration adjustments from Other Gas Cost charges since these were not filed during the review period. Witness Perry testified that by reflecting the information in this manner the Public Staff was able to reconcile the total cost of gas to the financial statements and was also now able to state that these amounts agree to the Public Staff's audited monthly deferred account files. Frontier did not take issue with the Public Staff's expressed desire that in future annual review proceedings Frontier would file annual review schedules that present a summary of its gas costs that agree with its monthly deferred account reports.

The Commission concludes that Frontier shall file its annual review schedules in its annual review filings in such a manner that they present a summary of the gas costs that agree with. Frontier's monthly deferred account reports.

IT IS, THEREFORE, ORDERED as follows:

1. That Frontier's accounting for gas costs during the 12-month period ended September 30, 2017, is approved.

2. That the gas costs incurred by Frontier during the 12-month period ended September 30, 2017, were reasonably and prudently incurred, and Frontier is hereby authorized to recover 100% of its gas costs incurred during the period of review.

3. That, Frontier's decisions regarding mitigation against price spikes are subject to Commission review annually in the Company's gas cost prudency review proceeding and the Commission has determined in this review proceeding that Frontier's hedging activities during the review period were reasonable and prudent.

4. That Frontier shall address its hedging policy and program in its testimony in its next annual gas cost prudency review, explaining why and how it hedged or why it did not hedge during the test period.

5. That Frontier shall use the net-of-tax overall rate of return of 6.60% as the applicable interest rate on all amounts over-collected or under-collected from customers reflected in its Deferred Gas Cost Account, effective January 1, 2018.

6. That Frontier shall file its annual review schedules in its annual review filings in such a manner that they present a summary of the gas costs that agree with Frontier's monthly deferred account reports.

ISSUED BY ORDER OF THE COMMISSION.
This the 8th day of June, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

DOCKET NO. G-9, SUB 698

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Piedmont Natural Gas Company, Inc., for Approval of Appendix F to its North Carolina Service Regulations	)))	ORDER APPROVING APPENDIX F AND ESTABLISHING PILOT PROGRAM

BY THE COMMISSION: On December 6, 2016, Piedmont Natural Gas Company, Inc. (Piedmont or the Company), filed a petition in the above-captioned docket requesting approval of proposed Appendix F, Statement of Alternative Gas Requirements, to its Service Regulations (Initial Version). Proposed Appendix F sets forth the terms and conditions under which Piedmont will accept Alternative Gas[1] into its system and deliver or redeliver it to Piedmont's customers. Piedmont states that the need for establishing such terms and conditions has arisen due to the potential for sourcing supplies of methane from non-traditional suppliers, including landfills, swine waste-to-energy facilities, and poultry waste-to-energy facilities.

On December 6, 2016, in Docket No. G-9, Sub 699, Piedmont filed an Application for Approval of a Receipt Interconnect Agreement between Piedmont and C2e Renewables NC (C2e), which relates to the construction of new natural gas distribution lines and facilities to receive Alternative Gas supplies from C2e at a designated receipt point.

Between December 20, 2016 and February 3, 2017, timely petitions to intervene were received and granted for the North Carolina Pork Council (NCPC); North Carolina Sustainable Energy Association (NCSEA); Enerdyne Power Systems, Inc. (Enerdyne); and the Coalition for Renewable Natural Gas (RNG).

On January 12, 2017, the Commission issued an Order Requesting Comments that (1) initiated an investigation of Piedmont's request to amend its Service Regulations; (2) directed that Public Service Company of North Carolina, Inc. (PSNC); Frontier Natural Gas Company (Frontier); Toccoa Natural Gas; the Public Staff-North Carolina Utilities Commission (Public Staff); and the North Carolina Attorney General be deemed to be parties to this proceeding; and (3) established a schedule for further interventions and for the Public Staff and other parties to file comments and reply comments.

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[1] "Alternative Gas" is defined in Appendix F as:

> gas capable of combustion in customer appliances or facilities which is similar in heat content and chemical characteristics to natural gas produced from traditional underground well sources and which is intended to act as a substitute or replacement for Natural Gas (as that term is defined in Piedmont's North Carolina Service Regulations). Alternative Gas shall include but not be limited to biogas, biomethane, and landfill gas, as well as any other type of natural gas equivalent produced or manufactured from sources other than traditional underground well sources. For purposes of the application of Piedmont's rate schedules and its Service Regulations, Alternative Gas shall be treated in a manner equivalent to "Gas" or "Natural Gas" except to the extent that this Statement of Alternative Gas Requirements specifies more restrictive obligations applicable to Alternative Gas, in which case the provisions of this Statement of Alternative Gas Requirements shall control.

NATURAL GAS – MISCELLANEOUS

On January 24, 2017, in Docket No. G-9, Sub 701, Piedmont filed an Application for Approval of a Receipt Interconnect Agreement between Piedmont and Optima KV, LLC (Optima KV), which relates to the construction of new natural gas distribution lines and facilities to receive Alternative Gas supplies from Optima KV at a designated receipt point.

On February 20, 2017, comments were filed by the Public Staff, PSNC, NCPC, Enerdyne, NCSEA, and RNG.

On March 13, 2017, reply comments were filed by Piedmont, PSNC, NCPC, Enerdyne, NCSEA, and RNG.

On March 13, 2017, Duke University filed a Petition to Intervene Out-of-Time. On March 14, 2017, the Commission issued an Order granting Duke University's request to intervene out of time.

On May 4, 2017, the Commission issued an Order Requiring Collaborative Meetings, Reports and Additional Information. In summary, that Order made clear that, after careful consideration of the parties' positions evidenced through comments and reply comments, good cause existed for the Commission to request that the parties engage in further discussions to attempt to resolve remaining issues. That Order directed the Public Staff to convene and facilitate meetings of the parties for the purpose of discussing the remaining unresolved issues. Additionally, that Order directed the Public Staff to file reports informing the Commission of the status of the collaborative process and the progress made in developing Alternative Gas standards for Piedmont. Further, that Order directed that the Public Staff's reports include responses to questions posed by the Commission, which were set forth in Attachment A to that Order and which were intended to supplement the record in this proceeding with information related to existing standards for quality and testing of natural gas and Alternative Gas in effect in other states, how well those standards are working, and whether those standards may be applicable in North Carolina.

On May 10, 2017, the Commission issued an Order Approving Agreements with Conditions in Docket No. G-9, Subs 699 and 701, conditionally approving the Receipt Interconnect Agreements between Piedmont and C2e, and Piedmont and Optima KV, respectively, as amended. The Commission directed Piedmont and C2e and Piedmont and Optima KV to comply with Appendix F, as proposed by Piedmont and being considered by the Commission in this docket. The Commission made clear that the Agreements between Piedmont and C2e and Piedmont and Optima KV are to be subject to any revisions to Appendix F that may be made by the Commission, as well as any applicable amendments to the Commission's Rules and Regulations.

On June 28, 2017, July 31, 2017, August 30, 2017, and October 3, 2017, the Public Staff filed reports on the meetings of the parties facilitated by the Public Staff to discuss Piedmont's proposed Appendix F and the parties' responses to the Commission's questions.

On October 26, 2017, Piedmont filed a revised Appendix F, amended to reflect discussions had during the collaborative process (Revised Version). Piedmont represented to the Commission that the revised version of Appendix F had been reviewed by the parties to the collaborative process and that, to the best of Piedmont's knowledge, there were no remaining objections to the Alternative Gas standards.

On October 31, 2017, the Public Staff filed the final report as provided for in the Commission's May 4, 2017 Order (Public Staff Final Report), which included the parties' responses to the questions set forth in Attachment A to that Order.

Discussion

This docket was opened upon the filing by Piedmont of a request for approval by the Commission of proposed Appendix F to Piedmont's Service Regulations, denominated as the Statement of Alternative Gas Requirements. Appendix F sets forth the terms and conditions under which Piedmont proposes to accept and receive "Alternative Gas" onto its system and pursuant to which it will continue to accept and redeliver such gas to customers receiving service from Piedmont.

In conjunction with its proposal of Appendix F, Piedmont submitted to the Commission two Receipt Interconnect Agreements (Agreements) between Piedmont and third party Alternative Gas suppliers. Those Agreements, one with C2e and the other with Optima KV, have been designated by Piedmont as confidential, consistent with N.C. Gen. Stat. § 132-1.2, and, thus, are not part of the public record of this proceeding.

Because the proposed injection and delivery of Alternative Gas into Piedmont's system raises potential service quality and operational concerns, the Commission initiated an investigation to consider such issues and directed that PSNC, Frontier, Toccoa Natural Gas, the Public Staff, and the North Carolina Attorney General were deemed to be parties to the proceeding. NCPC, NCSEA, Enerdyne, RNG and Duke University were allowed to intervene in the proceeding as parties. The Commission requested that the Public Staff and other parties file comments and reply comments on Piedmont's proposed Appendix F.

After careful consideration of the parties' comments and reply comments filed in this docket, the Commission concluded that good cause existed to direct the parties to engage in further discussions to attempt to resolve the remaining issues related to Appendix F and Piedmont's receipt of Alternative Gas. As a result, the Commission issued an order directing the Public Staff to convene and facilitate meetings of the parties for the purpose of discussing the remaining unresolved issues. In addition, the Commission sought to supplement the record by requiring the parties, as a part of the collaborative process, to answer specific questions related to service quality and operational concerns that remained for the Commission after having reviewing the comments and reply comments filed in the docket.

The Commission appreciates Piedmont's initial proposal for guidelines governing the acceptance of Alternative Gas. In addition, the Commission appreciates the time and effort of the Public Staff to facilitate and report on the collaborative process. The Commission recognizes the effort the parties have made to work toward consensus on Appendix F.

The Commission recognizes the advantages to the State of making use of Alternative Gas. Those advantages include the general benefits of utilizing renewable resources; developing a potential in-state gas supply; the development of an Alternative Gas industry in the State with its associated tax base and jobs; providing a cost-effective and environmentally sound way for North Carolina swine and poultry producers to manage animal waste; providing landfill operators another option for the sale of the methane that they are required to collect; providing electric utilities, including Piedmont's affiliates, Duke Energy Progress and Duke Energy Carolinas, with an option for complying with the statutory requirement that they generate a set percentage of their electricity with poultry and swine waste; and allowing third parties to purchase and utilize a renewable gaseous fuel with which, for example, to generate electricity and earn Renewable Energy Credits. Thus, the Commission supports Piedmont's efforts to introduce additional sources of renewable energy to its North Carolina customers. However, the Commission must ensure that Piedmont provides adequate, reliable and economical service to its customers and that Piedmont's decision to receive Alternative Gas does not jeopardize the Company's ability to do so.

As stated in the May 4, 2017 Order:

> While there are clear benefits to the State to accommodating the receipt of Alternative Gas into the local distribution systems, the Commission is not persuaded that there is an obligation, particularly in the sense of a common carrier obligation, for LDCs to accept Alternative Gas. The LDCs' distribution systems were built to receive natural gas from the interstate pipeline system and deliver it to customers. The system has been paid for by the LDCs' customers.[1] Alternative Gas producers and other interests are asking to use the natural gas distribution system for a purpose for which it was not intended. If that can be done while holding natural gas customers harmless, then every effort should be made to accommodate interconnections with Alternative Gas providers. However, the standards for delivery of Alternative Gas must be set to require delivery into the natural gas distribution system without degrading the quality of service to natural gas customers, particularly those customers just downstream from Alternative Gas projects.

May 4, 2017 Order, p. 15.

After consideration of the record in this proceeding, and the revisions made to Appendix F subsequent to the collaborative process, the Commission has determined that it would be premature to approve unconditionally Piedmont's Appendix F, in light of the Commission's ongoing concerns related to potential service quality and operational issues. Instead, the Commission approves the Revised Version of Appendix F, as further modified in this order, as a pilot program for a period of three (3) years. During the pilot period, Piedmont will report to the Commission, as detailed below, to provide information regarding the impact of Alternative Gas on its system operations and, ultimately, its customers. Piedmont and/or other Alternative Gas suppliers may apply to the Commission to participate in the pilot program; however, it must be demonstrated to the Commission that such additions will be useful in gathering the information and data sought by the Commission. At the end of the three (3) year period, the Commission will

[1] A more accurate statement is that the system was paid for by the LDC's investors, and the investors are being repaid by customers over time through rates.

consider additional modifications to Appendix F, based on the experience gained during the pilot period.

The specific revisions made to Appendix F subsequent to the collaborative process are addressed below, in addition to the Commission's ongoing service quality and operational concerns, several of which do not pertain to specific revisions.

Testing Requirements

In general, Piedmont's proposed testing regimen is designed to test Alternative Gas prior to its initial receipt by Piedmont, on a periodic basis following initial receipt by Piedmont, when the process or compounds used to produce Alternative Gas change, and before the reinstitution of deliveries in circumstances where receipt has been disrupted as a result of non-compliance with Piedmont's standards. Appendix F includes a testing regimen consisting of five types of testing: 1) Initial, 2) Subsequent, 3) Quarterly, 4) Supplemental, and 5) Alternative Gas Source, required if a supplier determines to alter its source of production or take action that might change the character or constituents of its gas. The comments and reply comments included extensive discussion of the proposed testing requirements. Piedmont justified its proposal by explaining that if it were going to accept Alternative Gas, "third-party producers desiring to supply Alternative Gas to North Carolina customers through LDC facilities have the obligation to establish that their Alternative Gas will meet the requirements of Commission Rule R6-30." Piedmont Reply Comments, at p. 9. Commission Rule R6-30 requires that "[a]ll gas supplied to customers shall be substantially free of impurities which may cause corrosion of mains or piping, or form corrosive or harmful fumes when burned in a properly designed and adjusted burner." Duke University commented that that there are a limited number of laboratories capable of analyzing the full suite of compounds listed in Appendix F and that for some tests, on-site sampling by a dedicated laboratory technician is required to ensure sample integrity and successful testing. Moreover, Duke University considered the testing costs, at approximately $21,000 per sample for the full suite of compounds, as not insignificant and, therefore, having the potential to materially affect biogas development by substantially increasing testing complexity and costs. Duke University commented that the lack of capable laboratories together with the high cost of testing, particularly in instances in which multiple tests may be required or in which quantities injected are small in comparison to the flow in the pipeline, could present an overly burdensome barrier to Alternative Gas development in North Carolina. Public Staff Final Report, p. 4.

Subsequent to the collaborative process, Piedmont made five revisions to the testing regimen established in Appendix F. First, with regard to Initial Testing, the Initial Version required the supplier to provide Piedmont with the results of two consecutive independent laboratory tests, performed no less than seven days apart, demonstrating that the Alternative Gas conforms to the Appendix F standards. The Revised Version requires the supplier to submit one independent laboratory test before the initial receipt of gas and a "laboratory test" on a second sample taken at least seven days and no more than fourteen days after the initial test sample. The Revised Version allows the supplier to deliver gas to Piedmont's system after the results of the first test have been provided to Piedmont and makes clear that the second test must be made on a second sample. The Initial Version called for two tests, no less than seven days apart. The Revised Version clarifies that receipt of Alternative Gas may begin after the first test and adds that the second test must occur within fourteen days. Appendix F requires that, after the initial receipt of Alternative Gas by

Piedmont, three additional consecutive tests be conducted at least thirty days apart, and the results be provided to Piedmont. The clarification that the initial receipt of gas may begin after the results of the first test are provided to Piedmont means that the test conducted seven to fourteen days after the first test qualifies as the first of the three consecutive tests. In other words, the Initial Version required a total of five tests; as clarified, the Revised Version requires four tests.

Second, Subsequent Testing is required if receipt of supplier's Alternative Gas is interrupted or suspended. Similar to the requirements for Initial Testing, the Initial Version required the submittal of two consecutive independent laboratory tests, performed no less than seven days apart, demonstrating compliance with Appendix F standards. The Revised Version requires the supplier to submit one independent laboratory test before the resumption of the receipt of gas and a "laboratory test" on a second sample taken at least seven days and no more than fourteen days after the first test sample. The Revised Version allows the supplier to deliver to Piedmont's system after the results of the first test have been provided to Piedmont and makes clear that the second test must be made on a second sample. The Revised Version also clarifies that Subsequent Testing is required only when Piedmont exercises its option to stop receiving Alternative Gas and does not apply to disruptions that occur in the normal course of business.

The Commission concludes that the first two revisions to the testing protocols amount to simple and reasonable clarifications and, therefore, are accepted.

The third revision involves the Quarterly Testing requirements. Appendix F requires Quarterly Testing, pursuant to which the supplier must provide, on no less than a quarterly basis, the results from independent laboratory tests demonstrating compliance with Appendix F standards. The Revised Version allows Piedmont, at its own discretion, to waive Quarterly Testing where the percentage of Alternative Gas at a specific point is immaterial and the receipt of Alternative Gas at that point will not have a detrimental impact on Piedmont's system, its operation, or its customers.

The Commission interprets this waiver to be conditional. If the flow on Piedmont's system changes and the percentage of Alternative Gas at a specific receipt point is no longer immaterial and may have a detrimental impact on Piedmont or its customers, then the Commission expects that Quarterly Testing would again be required of the supplier. Subject to this understanding, the Commission concludes that the waiver provision is reasonable and should be accepted.

Appendix F requires a supplier to promptly notify Piedmont of a decision to alter its source of production or take action that might otherwise change the characteristics of its gas stream. Appendix F provides that Piedmont shall have no obligation to receive Alternative Gas from a supplier under these circumstances until it has been provided with the results of two consecutive independent laboratory tests, performed no less than seven days apart, indicating compliance with Appendix F standards. The Revised Version allows a supplier to request that Piedmont waive testing for one or more constituents, "where certified field testing equipment satisfactory to Piedmont is available to test for those components."

As noted by Duke University, the testing requirements included in Appendix F are expensive. Reducing the number of constituents in a "full suite of compounds" to be submitted for laboratory tests could reduce costs. Ultimately, it is Piedmont's responsibility to ensure that its system is operated in a safe and reliable manner; however, the use of field testing equipment in lieu of laboratory testing, in those instances acceptable to Piedmont, appears to be a reasonable measure that would provide Piedmont with the evidence it requires as to gas quality and that might also reduce costs for the supplier. The Commission concludes that Piedmont should be allowed to waive laboratory testing requirements where certified field testing equipment satisfactory to Piedmont is available.

The fourth and fifth revisions pertain to the testing requirements for Alternative Gas Sources. In general, Appendix F requires a supplier to provide advance notice to Piedmont of any decision to alter source of production of Alternative Gas or otherwise take action that might change the characteristics or constituent components of its gas stream. Piedmont has no obligation to receive such gas until it has been provided with the results of two consecutive independent laboratory tests, performed no less than seven days apart, demonstrating that the gas meets the standards set forth in Appendix F. The fourth revision allows Piedmont to consider requests for waivers of the requirement to test for one or more constituent compounds, if two consecutive laboratory tests demonstrate non-detectable levels of the constituent. The fifth revision allows Piedmont to consider requests for waivers of the requirement to test for constituent compounds if two consecutive laboratory tests demonstrate non-detectable levels of the constituent. Piedmont may grant or deny any such request, subject to the requirement that Piedmont must state the basis for the decision in sufficient detail to facilitate review of that decision by the Commission.

Various parties provided comments on whether testing of certain constituents should be required. NCPC noted that vinyl chloride and siloxanes are not in swine waste, and, therefore, testing for those should not be required. NCSEA, commenting on California's biogas standards, stated that the California legislature has directed state agencies to revisit rules and to study specific issues relating to, among other things, maximum siloxane specifications. RNG commented on the "Constituents of Concern" in the Initial Version of Appendix F. It argued biomethane does not include p-Dichlorobenzene, n-Nitroso-do-n-propylamine,[1] antimony lead, and methacrolein and requested that, if tests for these constituents were required, the testing not be required after a showing that the biomethane does not contain them. RNG also commented that arsenic has not been found in biogas sources at milligram levels and that vinyl chloride was an issue only at one California hazardous waste landfill.

The revision to allow waivers of the testing requirements related to constituent compounds is supported by the comments of various parties that some Alternative Gas would not contain all of the constituent compounds included in the testing required by in the Initial Version of Appendix F. In addition, the revision is supported by Piedmont's willingness to adapt to experience gained. Specifically, in its Reply Comments, Piedmont noted that experience may demonstrate that certain types of Alternative Gas or individual constituents in such gas may not be problematic, and commented that if experience, either in the form of testing or actual operations, demonstrates that it is appropriate to modify the standards and/or testing regimen set forth in Appendix F, then Piedmont would expect that appropriate adjustments would be made to Appendix F.

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[1] RNG referenced "n-Nitroso-do-n-propylamine." Both versions of Piedmont's Appendix F included "n-Nitroso-di-n-propylamine" in its table of "Constituents of Concern."

Thus, the Commission concludes that these revisions respond to the concerns expressed by some of the parties as to whether constituents identified in Appendix F are found in biogas sources, implement Piedmont's explicit acknowledgement that experience may allow for reduced testing requirements, and, for this reason, are acceptable.

The Commission approves the testing requirements as set forth in the Revised Version with the expectation that experience and information gained during the pilot period will elucidate whether the testing requirements are barriers to entry for additional Alternative Gas suppliers and the appropriate testing regimen going forward.

The Commission recognizes that the testing requirements set forth in Appendix F are critical to Piedmont's ensuring the safe and reliable operation of its system. In response to a question from the Commission regarding what action would be taken if Piedmont's system were damaged by the receipt of Alternative Gas, Piedmont responded:

> Piedmont does not believe, based upon the information it is currently aware of, that the total exclusion of Alternative Gas is necessary but it does believe that prudent and cautious provisions regarding how and under what conditions such gas should be received should be adopted – at least until more experience with this new product is gained. If Alternative Gas is ultimately allowed onto the systems of North Carolina LDCs and damage to customer equipment or distribution/transmission facilities occurs, then that damage will be required to be repaired and the impacted facilities repaired or replaced. Delivery of the offending Alternative Gas should also be curtailed in those circumstances until additional mitigation measures are put into place to ensure no further damage to or degradation of equipment occurs as a result of the injection of Alternative Gas into LDC systems. Ultimately, changes to the provisions governing gas quality characteristics of Alternative Gas may need to be made.

Public Staff Final Report, pp. 15-16.

In the event of any damage to its system attributable to its receipt of Alternative Gas, Piedmont, not its customers, shall bear the risks of such damage. The Commission takes note of the fact that Piedmont has indicated that "[i]f Piedmont's proposed Alternative Gas standards, as revised on October 26, 2017, are approved, without modification, then Piedmont will accept responsibility for adverse customer impacts resulting from Alternative Gas received by Piedmont that is in compliance with those standards." Public Staff Final Report, p. 21. As such, the Commission expects Piedmont to ensure that a sufficient and appropriate testing regimen is required of suppliers in order to manage such risk.

Alternative Gas Quality Standards

Piedmont, in its Reply Comments, explained that Appendix F is targeted at ensuring: 1) the interchangeability of Alternative Gas with the geologic natural gas Piedmont has historically received from Transco and other upstream interstate natural gas pipelines; and 2) that the injection of Alternative Gas directly into Piedmont's system does not harm Piedmont's facilities, its customers' equipment, the public health, or the continuing reliability of service to Piedmont's customers. Piedmont Reply Comments, pp. 13-14. To this end, Appendix F establishes Alternative Gas Quality Standards with which any Alternative Gas delivered to Piedmont must comply.

With respect to gas quality, Piedmont is proposing to receive Alternative Gas into a distribution system that is currently fed by interstate pipelines. Natural gas, as it is produced from underground wells, is not a homogeneous fuel. It is a "soup" of short-chain hydrocarbons, with methane as the "broth." Other hydrocarbons, inert gases, and other constituents in the gas stream impact both the heat content and the ability of any particular "recipe" of gas to flow through the orifices in a burner. Interstate pipelines collect gas that is almost exclusively from underground wells, blend gas of varying constituents and quality, and deliver it to customers, including local distribution companies and their customers. The gas quality standards of interstate pipelines are set to accommodate a wide range of gas quality with the understanding that the gas will be blended before ultimately delivering a much more homogeneous product to the end user.

Comments presented in this docket made clear how little variation is seen in the blended gas delivered to Piedmont by its primary interstate supplier. As was shown in Piedmont's response to NCPC's Data Request No. 1, Piedmont's primary interstate pipeline supplier, Transco, typically shows a heat content with slight variations. NCPC Comments, Attachment 2. Likewise, the content by volume of nitrogen and carbon dioxide of gas on Transco was shown to be well below the maximum volumetric standards proposed by Piedmont in its Initial Version of Appendix F. The fact that the blended gas delivered by the interstates is more homogeneous allows local distribution companies like Piedmont to deliver a product to its customers that can be fairly billed on the basis of heating value and that burns in gas-fired equipment in an acceptably consistent manner. The Commission is concerned, in general, that Alternative Gas delivered to Piedmont would be consistently lower in quality than the blended gas delivered to Piedmont by Transco. As noted by Piedmont, "unlike larger interstate pipelines with ample sources of supply throughout their systems, Piedmont has very little ability to blend Alternative Gas with pipeline-delivered natural gas ...." Piedmont Reply Comments, p. 19.

Piedmont's modeling for the two Alternative Gas interconnection arrangements indicates that some customers may receive up to 100% Alternative Gas under certain operating conditions. Piedmont Reply Comments, fn. 8. In this situation and to the extent additional Alternative Gas suppliers request receipt agreements from Piedmont, the potential for the delivery of low-quality gas and associated risks to customers increases.

Subsequent to the collaborative process, four revisions to the Alternative Gas Quality Standards included in Appendix F were proposed.

The first revision involves the standard for the heating value of Alternative Gas. The Initial Version established a standard of between 980 and 1100 Btu/SCF at dry gas conditions. While the Revised Version maintains this standard, it allows Piedmont, at its own discretion, to receive gas with a heating content as low as 960 Btu/SCF. The Revised Version requires that any variance from the minimum level of 980 Btu/SCF must be granted on a non-discriminatory basis and must be set forth in a written waiver describing the scope and duration of the allowed variance.

The Initial Version established a heating value standard by relying on Transco's heating standard range of 980 Btu/SCF to 1100 Btu/SCF. Piedmont commented that a review of historical gas chromatograph data from Transco indicated that the average heat content of natural gas delivered to Piedmont has been very consistently measured at or near 1030 Btu/SCF and that, for this reason, Piedmont could have reasonably proposed that Alternative Gas delivered directly into its system match the heat content of the natural gas it has actually received from Transco. Piedmont Reply Comments, p. 19. Piedmont's response to NCPC's Data Request No. 1 summarized information on gas quality from Transco's Station 150 from October 1, 2016, through December 13, 2016. NCPC Comments, Attachment 2. That response shows a heating value range of 1027 Btu/SCF to 1051 Btu/SCF, with an average of 1031 Btu/SCF. The Commission itself monitors the gas quality information on Transco's 1Line electronic bulletin board and agrees that that range shown during the period described above is representative of the narrow range of heating values actually delivered by Transco after blending all of the gas it receives.

Piedmont maintains eleven "common gas areas" (CGAs) with different heat factors according to the heat content of the gas in those regions. The Public Staff suggested that Piedmont may want to implement "sub areas" if the injection of Alternative Gas begins to significantly change the heat content of a particular CGA. The Public Staff concluded that the CGAs (and possible sub areas) employed by Piedmont maintain reasonable accuracy for customer billing purposes. Public Staff Final Report, pp. 23, 29. According to Piedmont, CGAs are periodically evaluated, including when new receipt points are added. Piedmont plans to continue monitoring and evaluating its CGAs with the addition of receipt points for Alternative Gas supplies and will modify its CGAs as necessary to ensure that no customers are adversely impacted as Alternative Gas receipt points are added. Public Staff Final Report, p. 24.

The Heating Value standard established in the Revised Version is not representative of the heat content of gas actually delivered to Piedmont by Transco. Comments in this docket make it clear that it is economically burdensome for Alternative Gas suppliers to reach the 980 Btu/SCF minimum, much less surpass that level. The Commission is concerned with Piedmont's agreeing to accept gas with a lower heating value. Nevertheless, the Commission accepts the Heating Value standard set forth in the Revised Version, with the understanding that the pilot program will allow for the collection of data related to the actual heating value of the Alternative Gas delivered as well as any potential impacts to customers, and that Piedmont plans to continue monitoring and evaluating its CGAs with the addition of receipt points for Alternative Gas supplies and will modify its CGAs as necessary to ensure that no customers are adversely impacted as Alternative Gas receipt points are added.

The Commission is not prepared to accept, at this time, Piedmont's right to allow a variance to the minimum heating value standard as low as 960 Btu/SCF. Piedmont commented that in the professional judgment of its engineers, who are responsible for safely and reliably operating Piedmont's transmission and distribution system, a heat content for Alternative Gas lower than 980 Btu/SCF would pose an unacceptable risk of operational problems with customer equipment. Piedmont Reply Comments, p. 19. In addition, comments received in this proceeding make clear that the processes used to raise Alternative Gas to 980 Btu/SCF are expensive. Granting Piedmont the authority to pick and choose which Alternative Gas suppliers are allowed to avoid that expense raises a fundamental question of fairness. If a compelling case can be made to allow an exception to the 980 Btu/SCF minimum standard, then it should be brought before the Commission for review and approval. For the reasons discussed above, the Commission concludes that the provision to grant Piedmont authority to waive the minimum Heating Value standard is not accepted.

The second revision involves the Interchangeability standard, which is intended to ensure that the Alternative Gas received by Piedmont is interchangeable with the geologic natural gas Piedmont has historically received from Transco and other upstream interstate natural gas pipelines. The Initial Version established a standard of "WOBBE 1290 and 1370." The Revised Version requires that the Alternative Gas received from any single supplier "stay within a WOBBE variance range equal to or less than 4%."

Although the Initial Version established a standard of two discrete Wobbe numbers of 1290 and 1370, the Commission interpreted this standard to be a range of acceptable Wobbe numbers. The Commission understands a Wobbe number range as representing a range within which any Wobbe number achieved would not require adjusting gas-fired equipment. The mid-point of a Wobbe number range from 1290 to 1370 is 1330. The variance from the mid-point to 1290 and 1370 is about 3%. In effect, that is the percent tolerance that Piedmont represented to the Commission would be appropriate in the Initial Version.

Without explanation or justification, the Revised Version proposes a Wobbe number variance range of 4%. The Revised Version does not establish a Wobbe number range or reference point for the variance. Enerdyne included in its comments a whitepaper published by the Gas Technology Institute that referenced a "proposed acceptable variation of Wobbe Index of +/- 4% from historical values and the upper limit of 1400 BTU/SCF." Enerdyne Comments, EPS Exhibit 2, p. 13. However, the Public Staff's Final Report does not explain why a 4% variation of Wobbe numbers lacking any reference point should be adopted in place of Piedmont's Wobbe number range included in the Initial Version.

The Commission concludes that a range from a minimum Wobbe number to a maximum Wobbe number should be included in Appendix F and that the range should be such that customers' burners will not require adjustment. The Commission, therefore, directs Piedmont to clarify whether the listing of two discrete points instead of a range in the Initial Version was an oversight. If so, and if such a range allows for interchangeability, then an Interchangeability standard of "WOBBE from 1290 to 1370" is appropriate. If not, the Commission directs Piedmont to revise the Interchangeability standard to a range of Wobbe numbers that will allow for interchangeability and will ensure that it meet its responsibilities under Commission Rules R6-18(2) and R6-34(c). If Piedmont submits a Wobbe number range that is lower than 1290 and/or higher than 1370, the Commission directs Piedmont to provide a detailed explanation for its basis for widening the range.

Additionally, given Piedmont's lack of experience in receiving Alternative Gas, the Commission directs Piedmont to amend Appendix F to require that heat content and Wobbe numbers be reported daily to Piedmont by Alternative Gas suppliers.

The third and fourth revisions involve the Nitrogen and Total Inerts standards. The Initial Version established a Nitrogen standard of 2% by volumetric basis. The Revised Version eliminates the Nitrogen standard. The Initial Version established a Total Inerts standard of 3.2% by volumetric basis. The Revised Version increases the Total Inerts standard to 4.8% by volumetric basis. Neither the Initial Version nor the Revised Version defines what is meant by "Total Inerts."

As is made clear in the comments, nitrogen affects the quality of the gas – the higher the concentration of nitrogen, the lower the heating value and efficiency of combustion. Piedmont Reply Comments, p. 24. Piedmont noted that the percentage of nitrogen in the gas stream Piedmont has received from Transco historically has been very low, which contributes to the variance between the heat content of gas actually received from Transco and the 980 Btu/SCF standard proposed by Piedmont. Further, Piedmont noted that increasing tolerance levels of nitrogen would make it that much more difficult to attain appropriate heat content levels. Piedmont Reply Comments, p. 24. In response to NCPC's Data Request No. 1, Piedmont provided the gas quality composition at Transco's Station 150 between October 1, 2016, and December 13, 2016. NCPC Comments, Attachment 2. Although Transco has no Nitrogen standard, NCPC's Data Request No. 1 also showed that the maximum nitrogen composition of Transco's gas for the period was only 0.823%, with a minimum of 0.356% and an average composition of 0.649%. The maximum nitrogen composition of Transco's gas delivered during the period, therefore, was less than half of Piedmont's initial proposed standard of 2% by volumetric basis.

Various parties to the proceeding deemed the Nitrogen and Total Inerts standards included in the Initial Version to be arbitrary and capricious and pointed to the Nitrogen and Total Inerts standards of interstate pipelines to support of their positions calling for more liberal standards. For example, NCPC made note of the fact that the Atlantic Coast Pipeline's standard for Nitrogen is 4% and for Total Inerts, 5%. Public Staff Final Report, p. 52. However, the Commission notes that the interstate pipeline system is fundamentally different from that of a local distribution system. Interstate pipelines blend lower quality gas with higher quality gas and deliver gas to LDCs like Piedmont within a narrow quality range. Further, as noted above, Piedmont has indicated that there may be certain conditions under which its customers receive 100% Alternative Gas. Thus, the Commission notes that increased concentrations of nitrogen, as would be allowed under the Revised Version, in the situation where a customer is receiving 100% Alternative Gas would result in that customer's receiving an even lower quality gas. Piedmont generally defended the standards set forth in the Initial Version as being reasonable and prudent at this time in comparison to other gas quality standards applicable to Alternative Gas, particularly with regard to its lack of experience with Alternative Gas. Piedmont advised that the Commission should err on the side of caution in approving such standards in order to preserve the integrity, reliability, and safety of Piedmont's continuing service in North Carolina. Piedmont Reply Comments, pp. 23-25.

Various parties to the proceeding commented on the expense associated with reducing concentrations of these constituents in Alternative Gas. For example, when discussing the cost associated with decreasing the nitrogen content of Alternative Gas, RNG indicated that while nitrogen rejection units are one solution to increasing heating content and decreasing nitrogen concentration in product gas, such technology is not commonly deployed in the context of Alternative Gas projects because it adds to project complexity, cost ($3-10 million in CAPEX, and as much as 30% more power consumption), and methane loss (as much as 15% or more of a project's methane is lost), which translates to revenue loss. Public Staff Final Report, p. 11.

The Nitrogen and Total Inerts standards were modified in the Revised Version to be more liberal, consistent with the requests of the parties involved in the promotion and expansion of the use of various forms of Alternative Gas. These revisions were made with no explanation by Piedmont, in spite of the concerns it expressed regarding lack of experience with Alternative Gas and the need to proceed with caution when setting gas quality standards.

The Commission also takes note of the fact that the both the C2e project and the Optima KV project are subject to the Nitrogen and Total Inerts standards set forth in the Initial Version. Thus, at least these two suppliers determined that compliance with the standards set forth in the Initial Version is feasible.

For these reasons, the Commission concludes that the Nitrogen and Total Inerts standards set forth in the Revised Version are not acceptable. The Commission concludes that Appendix F should include the Nitrogen and Total Inerts standards set forth in the Initial Version, which Piedmont defended as being reasonable in light of its lack of experience with Alternative Gas. Additionally, the Commission concludes that Appendix F should be amended to include a definition of "Total Inerts."

Service Quality and Operational Concerns, Not Related to Specific Revisions to Appendix F

Change in Character of Service

Commission Rule R6-18 addresses changes in character of service and establishes the procedure to be followed in the event of a material change in the character of gas service. The rule draws a distinction between whether or not a material change is under the utility's control. Under Rule R6-18(1), changes under the utility's control can only be made with the approval of the Commission, and after adequate notice to the customers. Under Rule R6-18(2), in the context of changes that are not under the utility's control, the utility "shall maintain the proper combustibility of the gas supplied at the heating valve and specific gravity existing at the customers' meters."

The Commission is concerned that if the quality of gas to downstream customers – particularly the heat content – materially changes as a result of Piedmont decision to receive Alternative Gas, such change represents a "change under the control of the utility" within the meaning of Rule R6-18(1).

Both Piedmont and the Public Staff take the position that Piedmont's receipt of Alternative Gas, if done in compliance with Appendix F, would not constitute a change under the control of the utility. Public Staff Final Report, pp. 9, 27. Notwithstanding the position of the Public Staff and Piedmont, the Commission is concerned that a change in the composition of gas in a pipeline from geologically-derived pipeline gas with a heating value of 1030 Btu/SCF to 100% Alternative Gas at Appendix F's lower limit of 980 Btu/SCF might constitute a "material" change.

However, the Commission concludes that the impact on the customer is key to determining whether a material change has occurred. If Piedmont takes effective steps to bill the customer for the actual heat content of gas that they receive, and if the lower-heat-content gas does not adversely impact the performance of the customer's equipment and appliances, then an argument can be made that the impact on the customer is not material. Therefore, in order to evaluate impact on customers, the Commission directs Piedmont to provide written notice to customers located on its distribution pipeline that could be impacted by Alternative Gas with respect to the impact that

Alternative Gas could have on them. Such notice should include what to look for as an indication that the customer's equipment and appliances may need adjustment and how to contact Piedmont to obtain additional information. Piedmont should work with the Public Staff to develop an appropriate form for such public notice.

Piedmont's Right to Terminate Obligation to Receive

Both the Initial Version and the Revised Version of Appendix F include a provision allowing Piedmont to interrupt or suspend its receipt of Alternative Gas. Generally speaking, Piedmont may interrupt or suspend its receipt of Alternative Gas if the Alternative Gas proffered for delivery fails to meet the specifications of Appendix F until such Alternative Gas conforms to the standards set forth in Appendix F as verified by an "independent certified third-party laboratory satisfactory to Piedmont ...." Additionally, Piedmont has the right to interrupt or suspend its receipt of Alternative Gas under defined circumstances related to risk to public health or Piedmont's facilities until such time as correction of the problem has occurred as determined by Piedmont in the exercise of its discretion.

The Commission notes that interrupting or suspending receipt of Alternative Gas is a severe penalty, but also recognizes that Piedmont must have the right to suspend its receipt under certain circumstances, particularly where there is risk to public health or the system. The Commission is concerned, though, that, if rigorously enforced, the provision could unfairly penalize Alternative Gas suppliers. Specifically, the Commission is concerned that in the event of simple non-conformity with Appendix F standards, such as Heating Value or Interchangeability, verification from a laboratory is unnecessarily burdensome. Therefore, the Commission directs Piedmont to revise Appendix F to include a more moderate provision to address minor variances from the Heating Value, Interchangeability, and such other basic standards that do not reasonably require verification by an independent laboratory. Such provision should both ensure, to the extent possible, that customers are not harmed by an Alternative Gas supplier's failing to meet the standards of Appendix F and should provide strong encouragement for Alternative Gas suppliers to consistently meet the standards.

Impact on LNG Facilities

The Commission is aware that Piedmont's liquefied natural gas (LNG) facilities may be impacted by poor quality gas. Piedmont stated that the flow on the main 8-inch and 10-inch pipeline through Duplin County can flow south to north. Public Staff Final Report, p. 25. Piedmont's Barragan LNG facility in Bentonville is not far from that part of its system. The Commission directs Piedmont to inform the Commission of the possible impact that its receipt of Alternative Gas that is in compliance with the standards set forth in Appendix F, as amended and accepted in this Order, may have on the functioning of its LNG facilities.

Ongoing Reporting Requirements

In order that the Commission be kept apprised of the impact to customers of Piedmont's receipt of Alternative Gas and to gain understanding as Piedmont gains experience, the Commission directs Piedmont to report regularly to the Commission as follows:

1) Piedmont shall file a detailed report of each complaint received from any customer regarding Piedmont's receipt of Alternative Gas and the actions taken by Piedmont to resolve the complaint(s) no more than ten (10) business days from the date on which the complaint is received by Piedmont.

2) Piedmont shall file a report on April 1 and November 1 each year during the pilot period that includes the following information: i) the number of suppliers of Alternative Gas; ii) the monthly volume of Alternative Gas received during the previous 6-month period; iii) a detailed report of any complaints received from customers regarding Piedmont's receipt of Alternative Gas during the period, and the actions taken by Piedmont to resolve the complaint(s); and iv) the costs incurred by Piedmont to receive Alternative Gas that are not otherwise recovered under any receipt interconnection agreement.

3) In addition to the semi-annual report, Piedmont shall file in this docket, each month during the pilot period no later than fourteen (14) business days after the end of the month, a report documenting daily quantity, heat content and Wobbe numbers reported daily to Piedmont by Alternative Gas suppliers.

Conclusion

In summary, the Commission concludes that Piedmont's lack of experience with the receipt of Alternative Gas, in concert with Piedmont's fundamental obligation to provide safe and reliable service to its customers, dictate that the Revised Version of Appendix F, as modified herein, should not be approved unconditionally, but rather approved as a time-limited pilot program. The pilot program will allow Piedmont to gain experience with the receipt of Alternative Gas. If experience, either in the form of testing or actual operations, demonstrates that it is appropriate to modify the standards and/or testing regimen set forth in Appendix F, then the Commission will consider such modifications at the end of the pilot period. Therefore, the Commission approves the Revised Version of Appendix F, as modified in this order, as a pilot program for a period of three years. During the pilot period, the Commission directs Piedmont to file, semi-annually, a report providing information regarding the impact of Alternative Gas on its system operations and, ultimately, its customers. Piedmont and/or other Alternative Gas suppliers may apply to the Commission to be approved to participate in the pilot program; however, it must be demonstrated to the Commission that such additions will be useful in gathering the information and data sought by the Commission. At the end of the three-year period, the Commission will consider modifications to Appendix F based on the experience gained during the pilot period.

IT IS, THEREFORE, ORDERED as follows:

1. That Piedmont shall file with the Commission within sixty (60) days from the date of this Order a revised version of Appendix F that complies with the requirements of this Order as follows:

a. With respect to the Heating Value standard, strike Piedmont's authority to allow a variance to the minimum heating value standard as low as 960 Btu/SCF;

b. With respect to the Interchangeability standard, revise to include an appropriate range of Wobbe numbers, with detailed explanation as directed in this Order;

c. With respect to the Heating Value standard and the Interchangeability standard, revise to require that heat content and Wobbe numbers be reported daily to Piedmont by Alternative Gas suppliers;

d. With respect to the Nitrogen standard, revise to the standard included in the Initial Version;

e. With respect to the Total Inerts standard, revise to define "Total Inerts" and revise to the standard included in the Initial Version; and

f. With respect to the Termination of Obligation to Receive Gas section, revise to include provision to address minor variances from the Heating Value, Interchangeability, and such other basic standards that do not reasonably require verification by an independent laboratory;

2. That the Revised Version of Appendix F, as amended herein, is approved for use as a pilot program for a three-year pilot period, beginning on the date of the Commission's order accepting Appendix F to be filed by Piedmont in compliance with this Order;

3. That the C2e and the Optima KV projects shall be allowed to participate in the pilot program and that additional Alternative Gas suppliers shall be allowed to participate in the pilot program upon a showing to the Commission that any such project will aid in the information and data sought to be gathered through the pilot program;

4. That Piedmont shall file with the Commission within sixty (60) days from the date of this Order a detailed explanation of how it plans to monitor and evaluate its CGAs with the addition of receipt points for Alternative Gas supplies and modify its CGAs as necessary to ensure that no customers are adversely impacted;

5. That Piedmont shall file with the Commission within sixty (60) days from the date of this Order, after working with the Public Staff to develop an acceptable format, a notice to be provided to customers located on its distribution pipeline that could be impacted by Alternative Gas with respect to the impact that Alternative Gas could have on them;

6. That Piedmont shall file with the Commission sixty (60) days from the date of this Order a detailed explanation of the possible impact that its receipt of Alternative Gas that is in compliance with the standards set forth in Appendix F, as amended and accepted in this Order, may have on the functioning of its LNG facilities;

7. That Piedmont shall file a detailed report of any complaints received from customers regarding Piedmont's receipt of Alternative Gas during the pilot period and the actions taken by Piedmont to resolve the complaint(s) no more than ten (10) business days from the date on which the complaint is received by Piedmont;

8. That Piedmont shall file with the Commission, beginning sixty (60) days from the date of this Order and monthly thereafter, after working with the Public Staff to develop an acceptable format, a report documenting daily quantity, heat content and Wobbe numbers reported daily to Piedmont by Alternative Gas suppliers; and

9. That Piedmont shall file a report on April 1 and November 1 each year during the pilot period that includes the following information: i) the number of suppliers of Alternative Gas; ii) the monthly volume of Alternative Gas received during the previous 6-month period; iii) a summary of any customer complaints received during the reporting period related to the receipt of Alternative Gas and any actions taken by Piedmont to resolve the complaints; and iv) the costs incurred by Piedmont to receive Alternative Gas that are not otherwise recovered under any receipt interconnection agreement.

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of June, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

Commissioner Charlotte A. Mitchell did not participate in this decision

DOCKET NO. G-9, SUB 698

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Piedmont Natural Gas Company, Inc., for Approval of Appendix F to its North Carolina Service Regulations	)))	ORDER ACCEPTING COMPLIANCE FILING IN PART AND REQUIRING REVISIONS

BY THE COMMISSION: On December 6, 2016, Piedmont Natural Gas Company, Inc. (Piedmont or the Company) filed a petition in the above-captioned docket requesting approval of a proposed Appendix F to its Service Regulations. In summary, the proposed Appendix F (Initial Version) included a definition of "Alternative Gas" and set forth the terms and conditions under which Piedmont will accept Alternative Gas onto its system and deliver or redeliver it to the Company's customers. Piedmont stated that the need for establishing such guidelines has arisen due to the potential for sourcing supplies of methane from non-traditional suppliers, including landfills, swine waste-to-energy facilities, and poultry waste-to-energy facilities.

On June 19, 2018, the Commission issued an Order Approving Appendix F and Establishing Pilot Program (Appendix F Order). In the Order, among other things, the Commission directed Piedmont to file within 60 days a revised version of Appendix F that complied with the requirements of the Order, and to provide other information requested by the Commission.

On July 16, 2018, North Carolina Pork Council (NCPC) filed a motion pursuant to N.C. Gen. Stat. § 62-90(a) requesting that the Commission extend the time within which to file notice of appeal and exceptions to the Commission's Appendix F Order from Thursday, July 19, 2018, to Monday, August 20, 2018. On July 17, 2018, the Commission issued an Order granting the requested extension of time to file appeal for all parties.

On August 9, 2018, NCPC filed a Motion for Reconsideration, requesting that the Commission revise the Appendix F Order.

On August 20, 2018, Piedmont filed a Compliance Filing and Motion for Clarification and/or Reconsideration (Compliance Filing). In summary, Piedmont submitted Attachment A, Appendix F to its North Carolina Service Regulations revised to comply with the Commission's directives set forth in the Appendix F Order, submitted other items as directed by the Appendix F Order, and asked for clarification and/or reconsideration of several aspects of its Appendix F Order.

On October 1, 2018, the Commission issued an Order Denying Motions for Reconsideration and Granting in Part Motion for Clarification (Reconsideration Order). That order denied the motions for reconsideration filed by NCPC and Piedmont. Further, it granted Piedmont's request to revise Appendix F: (1) to modify the timing of the filing of the semi-annual report required in Ordering Paragraph No. 9 of the Appendix F Order, and (2) to make Piedmont rather than the Alternative Gas suppliers responsible for measuring and reporting to the Commission on a monthly basis the daily quantities, heat content, and Wobbe value of the Alternative Gas received by Piedmont.

Compliances

In Ordering Paragraph No. 1 of the Commission's Appendix F Order, the Commission directed Piedmont to revise Appendix F to, among other things: (1) strike Piedmont's authority to allow a variance to the minimum heating value standard as low as 960 Btu/SCF, (2) revise the Nitrogen standard to the standard included in the Initial Version, (3) define "Total Inerts," and (4) revise the Total Inerts standard to the standard included in the Initial Version. The Commission finds that Piedmont has complied with those requirements of the Appendix F Order.

Revision of Piedmont's Interchangeability Standard

Ordering Paragraph No. 1 of the Commission's Appendix F Order directed Piedmont to revise the Interchangeability standard to include an appropriate range of Wobbe numbers, with a detailed explanation of any changes.

In Piedmont's December 6, 2016 petition, its original Interchangeability standard was shown as "WOBBE 1290 and 1370." In the Appendix F Order, the Commission concluded "that a range from a minimum Wobbe number to a maximum Wobbe number should be included in Appendix F and that the range should be such that customers' burners will not require adjustment." It directed Piedmont to clarify whether the listing of two discrete points instead of a range in the Initial Version of Appendix F was an oversight. If so, the Commission directed that Piedmont use an Interchangeability standard of Wobbe from 1290 to 1370. The Commission stated that if the original use of two discreet points was not an oversight, Piedmont should revise the Interchangeability standard to a range of Wobbe numbers that will allow for interchangeability. The Commission added, "If Piedmont submits a Wobbe number range that is lower than 1290 and/or higher than 1370, the Commission directs Piedmont to provide a detailed explanation for its basis for widening the range."

In its Compliance Filing, Piedmont affirmed that the use of two discreet Wobbe numbers was an oversight, and that it had intended to use a range of 1290 to 1370. However, Piedmont also proposed a revised Wobbe range of 1285 to 1400. The Company stated that it, "believes that Alternative Gas within this range should pose no threat to existing customers or to the ability of customer equipment to burn such gas." Further, Piedmont explained that the lower limit of 1285 was determined using a heat content of 980 Btu/SCF and a specific gravity of 0.58, which was described as "the highest specific gravity Piedmont has experienced to date for Alternative Gas delivered to Piedmont by Optima KV – the only Alternative Gas producer actually delivering gas to Piedmont."

The Commission had Piedmont's Compliance Filing before it as of August 20, 2018, and considered that information in its Reconsideration Order. In the Reconsideration Order, the Commission stated:

> As expressed in the Appendix F Order, the Commission was convinced that the Wobbe range of 1290 to 1370 recommended by Piedmont in its Initial Version of Appendix F was appropriate. The Commission remains convinced on this point. Further, the Commission concludes that there are no new facts or additional information that support accepting Piedmont's suggested minor modification to the Wobbe range approved in the Appendix F Order.

Reconsideration Order, at p. 8.

The above conclusion incorporated the Commission's consideration of the facts cited by Piedmont in its Compliance Filing in support of its revised Wobbe range of 1285 to 1400. Specifically, the Commission was not persuaded that the ability of customer equipment to burn Alternative Gas is a sufficient criteria. Rather, the Commission placed significant weight on Piedmont's statement that the use of Piedmont's original 1290 to 1370 Wobbe numbers would not require adjustments to customers' burners. Flammable gas outside of a 1285 to 1400 Wobbe range has the ability to burn in gas equipment, as long as the equipment is adjusted to accommodate it. However, the essence of interchangeability is the ability of a stream of gas to burn in gas equipment without requiring adjustments. Given Piedmont's long-standing role and experience in maintaining the proper combustibility of the gas that it delivers to its customers, the Commission placed significant weight on Piedmont's original 1290 and 1370 Wobbe numbers as being the appropriate Wobbe range. Further, as it did in the Reconsideration Order, the Commission concludes that Piedmont did not provide persuasive support for the premise that gas with a Wobbe number as low as 1285 could burn in customers' gas equipment without requiring adjustments.

<u>Reporting of Daily Heat Content and Wobbe Values</u>

Also in Ordering Paragraph No. 1 of the Commission's Appendix F Order, the Commission directed that Appendix F be revised to require that Alternative Gas suppliers report heat content and Wobbe numbers to Piedmont on a daily basis. In its Compliance Filing, Piedmont duly made that revision. It included in Attachment C a form for the monthly report of Alternative Gas quantities, heat content, and Wobbe values.

However, in the same filing, Piedmont stated that it would prefer to gather that information directly through its own instruments. The Commission's Reconsideration Order granted Piedmont's request that Piedmont be responsible for measuring and reporting to the Commission on a monthly basis the daily quantities, heat content, and Wobbe value of the Alternative Gas that it receives, and directed that Appendix F be revised accordingly.

The Commission accepts Attachment C as the acceptable format for the monthly report of Alternative Gas quantities received, heat content daily average, and Wobbe daily average, with one addition. It directs Piedmont to add a column on the monthly report for specific gravity calculated to three decimal places.

The Commission notes that, if the quality of Alternative Gas is to be kept within the Appendix F Gas Quality Standards, it is important that it be documented that Alternative Gas suppliers are aware of the quality of gas that they are delivering on a daily basis and particularly are aware of any variance outside of the Alternative Gas Quality Standards. The Commission will leave it to Piedmont to propose a way to make Alternative Gas suppliers aware when their gas is not in compliance and to document that notification, as discussed more fully below.

Termination of Obligation to Receive Gas

In the Appendix F Order, the Commission raised a question about the "Termination of Obligation to Receive Gas" section in Appendix F. In addition to protecting the system and its customers, this provision also functions essentially as a penalty provision to compel compliance. The Commission noted that "Piedmont must have the right to suspend its receipt under certain circumstances, particularly where there is risk to public health or the system." However, it also noted that "interrupting or suspending receipt of Alternative Gas is a severe penalty." The Commission added that the provision requiring verification with a laboratory test before a supplier could resume injecting Alternative Gas into Piedmont's system, "in the event of simple non-conformity with Appendix F standards, such as Heating Value or Interchangeability," was unnecessarily burdensome. As a result, the Commission directed Piedmont:

> [t]o revise Appendix F to include a more moderate provision to address minor variances from the Heating Value, Interchangeability, and such other basic standards that do not reasonably require verification by an independent laboratory. Such provision should both ensure, to the extent possible, that customers are not harmed by an Alternative Gas supplier's failing to meet the standards of Appendix F and should provide strong encouragement for Alternative Gas suppliers to consistently meet the standards.

Appendix F Order, at p. 15.

In its Compliance Filing, Piedmont responded:

> In Attachment A, Piedmont has modified the provisions under Subsequent Testing to provide that laboratory testing may not be required prior to reconnection if the event that caused interruption or suspension of a supplier's Alternative Gas stream

consists of a non-material and/or incidental deviation from the specific Alternative Gas Quality Standards applicable to heating value, interchangeability, total sulfur, carbon dioxide, water, or hydrogen sulfide, so long as such deviations are not recurring in nature and do not pose a threat to Piedmont's facilities or equipment, the facilities or equipment of Piedmont's customers, or to Piedmont's ability to provide continuous, safe, and reliable service to the public.

Piedmont made no change under the Termination of Obligation to Receive Gas section, but rather addressed the change under Subsequent Testing. Consequently, the Commission's concern about an Alternative Gas supplier being unfairly penalized by disconnection for a relatively minor variance remains. Therefore, the Commission directs that Piedmont address this issue under the Termination of Obligation to Receive Gas section. A possible resolution would be a sentence acknowledging the possibility of minor variances, and stating that Piedmont will provide the supplier with reasonable notice of the minor variances and specify a date by which the supplier must correct the variances or face disconnection by Piedmont. The Commission directs that Piedmont file with the Commission within 30 days its proposal for providing such notice of noncompliance.

The Commission also notes that in the proposed changes to the Subsequent Testing section Piedmont did not include certain other Alternative Gas Quality Standards, such as those for nitrogen and oxygen, in its list of standards subject to the modified penalty provision. The Commission wishes to give Piedmont and the other parties to this docket as much flexibility as possible. However, the Commission monitors interstate pipeline electronic bulletin boards (EBB) – particularly 1Line, the EBB of Transcontinental Gas Pipe Line (Transco) – and is aware of the information that is available from the type of gas chromatograph used by Transco. There does not appear to be any reason that an Alternative Gas component that is listed on a gas chromatograph should require laboratory testing in the event of a suspension of receipt as a result of non-compliance. Therefore, the Commission directs Piedmont to modify the Termination of Obligation to Receive Gas section to reflect that when minor non-compliances involving those components of the Appendix F Alternative Gas Quality Standards that are reported daily on the installed gas measuring equipment result in suspension or interruption of service, an independent laboratory test will not be required prior to the resumption of service. Furthermore, Piedmont shall, within 30 days, make a filing explaining why it limited the components in the Alternative Gas Quality Standards not subject to laboratory testing to the ones included under Subsequent Testing in its Compliance Filing.

With the modifications requested above, the Commission will accept as part of the Pilot Program the continued reliance on disconnection as the only remedy for violations of Appendix F. The Commission encourages all parties to work diligently to ensure that Piedmont's Alternative Gas Quality Standards are consistently met, and it expects the disconnection remedy to be employed by Piedmont with appropriate discretion.

Customer Notification

In the Appendix F Order, the Commission noted that the impact of Alternative Gas on customers was key to determining whether a material change in Piedmont's service had occurred. The Commission stated:

> Therefore, in order to evaluate impact on customers, the Commission directs Piedmont to provide written notice to customers located on its distribution pipeline that could be impacted by Alternative Gas with respect to the impact that Alternative Gas could have on them. Such notice should include what to look for as an indication that the customer's equipment and appliances may need adjustment and how to contact Piedmont to obtain additional information.

Appendix F Order, at p. 15.

The Commission ordered Piedmont to work with the Public Staff to develop a notice to be provided to customers located on its distribution pipeline that could be impacted by Alternative Gas with respect to the impact that Alternative Gas could have on them.

Piedmont submitted Attachment D as the proposed form of customer notice agreed to by Piedmont and the Public Staff. While the notice submitted in Attachment D may be a good first step, it is not fully responsive to Ordering Paragraph No. 5 of the Commission's Appendix F Order, or the discussion about the customer notice in the body of the Order. The notice in Attachment D informs customers of the Commission's approval of quality standards, describes Alternative Gas, states that Piedmont is currently receiving Alternative Gas from a supplier near Kenansville, and extols the virtues of Alternative Gas. Beyond that, it simply states, "We do not anticipate any problems associated with our receipt of alternative gas and you should not notice any difference in the quality of service you have traditionally received from Piedmont."

The Commission notes that Piedmont's Attachment D customer notice describes the Commission-approved standards as being "...similar to standards applicable to production from traditional underground natural gas sources." That statement may be accurate as far as it goes, but it falls short of adequate notice because it does not inform the customer that such traditional underground gas can vary in quality, but is blended before being delivered. Therefore, the Commission directs that the phrase "which is similar to standards applicable to production from traditional underground natural gas sources" be stricken from the Attachment D notice.

The Commission recognizes that Piedmont is currently receiving Alternative Gas from only one supplier and the volumes from that supplier may currently be adequately blended with pipeline gas so that no impacts will be evident. Nevertheless, the Commission deems it appropriate for Piedmont to add some information to its customer notice about what to look for as a sign that Alternative Gas may be affecting the operation of the customer's equipment. As an example, the customer notice might state:

> We do not anticipate any problems associated with our receipt of alternative gas and you should not notice any difference in the quality of service you have traditionally received from Piedmont. However, if you do notice some difference

in the operation of you gas appliances, such as a constantly flickering flame, or an unusually orange or yellow flame for a period of time, please contact Piedmont at...

The Commission directs that Piedmont revise the Attachment D notice to conform with the Commission's directives above, and file the revised version within 30 days.

Impacts of Receipt of Alternative Gas on LNG Operations

In Ordering Paragraph No. 6 of the Appendix F Order, the Commission directed Piedmont to file with the Commission a detailed explanation of the possible impact that its receipt of Alternative Gas that is in compliance with Appendix F may have on the functioning of its LNG facilities. In compliance, Piedmont filed Attachment E, "Statement of Potential Impacts of Alternative Gas Receipts on Piedmont LNG Facilities." Piedmont described the impact that five components -- mercaptan, nitrogen, oxygen and toluene content, and gas temperature -- included in the Alternative Gas Quality Standards could have as "a low to medium impact on Piedmont LNG operations." Piedmont stated:

> Due to the critical importance and significant investment associated with these assets, Piedmont will not allow Alternative Gas facilities to be sited at locations that would result in quantities of such gas reaching its LNG sites at levels that would threaten the integrity of the liquefaction equipment. Piedmont will utilize system modeling tools to ensure the output of proposed Alternative Gas facilities does not impact its LNG operations.

The Commission appreciates Piedmont's candid assessment of this issue and approves its proposed solution.

Plan for Monitoring and Evaluating CGAs

In the Appendix F Order, the Commission ordered that Piedmont file within 60 days a detailed explanation of how it plans to monitor and evaluate its "common gas areas" (CGAs) with the addition of receipt points for Alternative Gas supplies, and how it will modify its CGAs as necessary to ensure that no customers are adversely impacted. Piedmont's report on CGA-related matters was attached to its Compliance Filing as Attachment F.

In Attachment F, Piedmont stated that it will use system modeling to assess heat content variances arising from Alternative Gas delivered at new receipt points. The Company stated:

> The modeling considers the amount of Alternative Gas relative to the flow of other, traditional natural gas sources into and across Piedmont's system in order to provide variances in the heat content of gas delivered to Piedmont's customers.

It further stated that:

> Piedmont's modeling indicates that no customer has been or will be materially impacted with respect to the heat content of the Alternative Gas received into Piedmont's system at Kenansville, NC at design flow rates.

A footnote in Piedmont's reply comments in this docket stated:

> Piedmont modeling for the two pending Alternative Gas interconnection arrangements indicates that some customers may receive up to 100% Alternative Gas under certain operating conditions.

Piedmont Reply Comments, fn. 8. The Commission interpreted the footnote to mean that customers downstream of Optima KV's Kenansville facility would see 100% Alternative Gas under some circumstances. Optima KV is the only Alternative Gas facility currently in operation. Piedmont's clarification that the Alternative Gas received into Piedmont's system from Optima KV at design flow rates would not materially impact the heat content of gas billed to downstream customers has the effect of deferring the need to address significant differences between the heat content of Alternative Gas and pipeline gas. Further, there does not appear to be an immediate need to establish a new CGA solely for measurement of the Appendix F standards of the Optima KV input.

In addition, Piedmont stated that "immaterial variances in heat content should not be addressed, since utility ratemaking and utility metering (absent a chromatograph on every customer meter) are not designed for perfect accuracy." The Commission agrees. It recognizes that avoiding burdensome administration and unjustified costs is a fundamental principal of utility ratemaking. In its January 25, 1990 order in Docket No. G-100, Sub 52, the Commission responded to a petition to require that bills be adjusted for atmospheric pressure. In that docket, the Commission stated, "any benefits derived from attempting to compensate for all potential measurement errors would be quickly offset by the added financial burden on [the] customers." Whether variances arise from measurement errors or differences in gas quality, there is a need to balance absolute accuracy in billing with reasonable costs.

Piedmont stated that its modeling indicates that the Alternative Gas received into its system at Kenansville will not cause a variance in heat content of more than 2% for any customer. It pointed out that gas meters are not designed for perfect accuracy and a 2% tolerance level is "included in approved meter testing protocols of both natural gas and electric utilities." It asserted that "variations within that range from Alternative Gas should not, in Piedmont's view, be considered meaningful or require adjustment." Piedmont references the standard of a 2% variance in meter accuracy as support for a 2% variance in heat content. The Commission takes note of the acceptable magnitude of meter accuracy. However, it also notes that a variance in metering accuracy could either suppress or amplify differences in the heat factor used to bill a customer within a CGA, and the actual content of the gas received by that customer.

The Commission has previously addressed the issue of variances between the heat content delivered to a customer and the heat-content billing factor used to bill that customer. In Public Service Company of North Carolina, Inc.'s (PSNC's) most recent general rate case, in Docket No. G-5, Sub 565, PSNC proposed to use a single, average heat-content adjustment factor to bill all of PSNC's North Carolina customers. PSNC witnesses testified that although PSNC was now receiving interstate gas from the south and the north, the difference in heat content was not significant.

The testimony in that PSNC rate case is consistent with Piedmont's statements in this docket that Transco's heat content does not vary much from 1030 Btu/SCF. Also, Piedmont's response to Data Request No. 1 from NCPC in this docket showed actual heat content data at Transco's Station 150 from October 1, 2016 through December 13, 2016. That Data Response showed a maximum heat content of 1051 Btu/SCF, a minimum of 1027 Btu/SCF, and an average of 1031 Btu/ SCF. NCPC Comments, Attachment 2.

In the PSNC rate case, the Commission did not determine how much variation is acceptable between the heat content delivered to a customer and the heat content factor used to bill that customer. However, since PSNC also depends heavily on Transco for its gas supply, the range of heat content values displayed in Piedmont's response to NCPC's data request is representative of the magnitude of variances in heat content that the Commission, in PSNC's rate case, agreed do not require bill adjustments. The Commission effectively recognized in the PSNC docket that, as Piedmont stated, "immaterial variances in heat content should not be addressed."

While the Commission recognizes that some variation between heat content billing factors and the actual heat content delivered is acceptable, it also notes that, with regard to the introduction of Alternative Gas, Piedmont's ratepayers should not have to pay for an unacceptable change in heat content or other attributes that might create added costs. Piedmont has stated that it intends to use CGAs to protect against such a result. The Commission agrees that Piedmont's decision to use eleven CGAs while receiving pipeline gas represents a commendably diligent effort to bill its customers fairly. However, comments in this docket made clear that at least some Alternative Gas producers would struggle to meet the low end of Piedmont's Alternative Gas Quality Standard Heating Value range. Further, as Piedmont made clear, there was relatively little variation in the heat content of pipeline gas with about 1030 Btu/SCF as the average value. Nevertheless, whether CGAs can effectively detect and measure a shifting null point between pipeline gas and low heat-content Alternative Gas without additional heat content measurements remains to be seen. This is one of the areas of uncertainty in which the Appendix F Pilot Program should help the Commission and parties gain an understanding. Pursuant to N.C. Gen. Stat. § 62-33, the Commission will work with Piedmont and the parties to better understand how the Company establishes its CGAs and what can be done to use CGAs to address how to ensure that customers are properly billed for natural gas containing Alternative Gas.

Additional Proposed Revision

In its Compliance Filing, Piedmont identified an omission in its Appendix F that it proposed to correct. As reflected on Attachment A, on page 2 of Appendix F under initial testing, Alternative Gas suppliers are required to provide the results of three consecutive lab tests of their gas performed no less than 30 days apart following Piedmont's initial receipt of Alternative Gas from a supplier. However, no upper limit as to when these test results must be provided was listed in Appendix F. If this loophole was utilized by a supplier, it would effectively eliminate the requirement to provide three consecutive lab tests following Piedmont's initial receipt of gas from such supplier. As a result, Piedmont proposed an upper limit of 45 days between such tests, and that proposed language is reflected on page two of Attachment A under the Testing Requirements section. Piedmont requested Commission authorization to include this change in its Appendix F. The Commission finds good cause to authorize Piedmont to include that change in Appendix F.

IT IS, THEREFORE, ORDERED as follows:

1. That the Interchangeability standard in Appendix F shall be a range of Wobbe numbers between 1280 and 1370, inclusive;

2. That Attachment C to Piedmont's Compliance Filing shall be modified to add a column that shows specific gravity calculated to three decimal places;

3. That within 30 days, Piedmont shall propose a modification to Appendix F that will describe a proposed notice and procedure by which an Alternative Gas supplier and the Commission will be promptly notified when the supplier is out of compliance with the Appendix F Alternative Gas Quality Standards, be given a specific date by which the variance must be corrected to avoid disconnection by Piedmont, and how such notification will be documented;

4. That the Termination of Obligation to Receive Gas provision of Appendix F shall be revised to reflect that when minor non-compliances involving those components of the Appendix F Alternative Gas Quality Standards which are reported daily on the installed gas measuring equipment result in suspension or interruption of service, an independent laboratory test will not be required prior to the resumption of service. Furthermore, Piedmont shall, within 30 days, file an explanation as to why it limited the components in the Alternative Gas Quality Standards not subject to laboratory testing to the ones included under Subsequent Testing in its Compliance Filing;

5. That Attachment D of Appendix F shall be revised as directed in the body of this Order and filed with the Commission within 30 days;

6. That Appendix F, Attachment A, page 2, shall be, and is hereby, revised to include an upper limit of 45 days between consecutive independent laboratory tests.

ISSUED BY ORDER OF THE COMMISSION.
This the 30th day of October, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

Commissioners Lyons Gray and Charlotte A. Mitchell did not participate in this decision

DOCKET NO. G-9, SUB 698

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Application of Piedmont Natural Gas	)	ERRATA ORDER
Company, Inc., for Approval of Appendix F	)	
to its North Carolina Service Regulations	)	

BY THE COMMISSION: On October 30, 2018, the Commission issued an Order Accepting Compliance Filing in Part and Requiring Revisions (Compliance Order) in the above-captioned docket. It has come to the Commission's attention that Ordering Paragraph No. 1 of the Compliance Order incorrectly stated the lower end of the approved range of Wobbe numbers as 1280, instead of the intended 1290. Therefore, the Commission finds good cause to correct Ordering Paragraph No. 1 of the Compliance Order by revising it to state as follows:

1. That the Interchangeability standard in Appendix F shall be a range of Wobbe numbers between 1290 and 1370, inclusive.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 2nd day of November, 2018.

NORTH CAROLINA UTILITIES COMMISSION
A. Shonta Dunston, Acting Deputy Clerk

DOCKET NO. G-40, SUB 142

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Frontier Natural Gas Company – Violations of Title 49, Part 192, Subpart O, Code of Federal Regulations	)	ORDER APPROVING MODIFICATION TO AGREEMENT AND STIPULATION OF SETTLEMENT

BY THE COMMISSION: On October 12, 2017, the North Carolina Utilities Commission – Pipeline Safety Section (Safety Staff) filed an Agreement and Stipulation of Settlement in this proceeding on behalf of itself and Frontier Natural Gas Company (Settlement) pursuant to which Frontier and the Safety Staff agreed to a resolution of all disputes between them in this docket. On October 31, 2017, the Commission approved the Settlement.

On May 31, 2018, Frontier filed a request for Approval of Modification to Agreement and Stipulation of Settlement. In its motion, Frontier states that the Settlement required Frontier, in consultation with Safety Staff, to perform an in-line inspection ("ILI") of a representative portion of its transmission system utilizing smart-pig technology and to also perform an internal corrosion direct assessment ("ICDA") for the Greenway and West Park segments of its transmission line by dates set forth in the Settlement. Frontier states that following approval of the Settlement and further discussions between Frontier and Safety Staff, Safety Staff and Frontier reached agreement that Frontier's ILI would include the Greenway and West Park sections of its transmission system. Frontier's ILI was conducted April 9, 2018 through April 20, 2018 and included the Greenway and West Park sections of its transmission system. Frontier states that inasmuch as an ILI inspection of the Greenway and West Park sections of its transmission system provides much more (and more granular) information about the condition of those segments of Frontier's transmission system than an ICDA would reveal, the Safety Staff and Frontier have agreed that an ICDA of those segments is no longer necessary. Thus, Frontier requests that the Commission approve the Amended Stipulation of Settlement attached to the Motion effectuating such agreement.

Upon consideration of the entire record in this proceeding, the Commission finds and concludes that approval of the Amended Stipulation of Settlement dated and filed on May 31, 2018, which modifies the Agreement and Stipulation of Settlement dated October 12, 2017, is in the public interest.

IT IS, THEREFORE, ORDERED that the May 31, 2018 Amended Stipulation of Settlement filed with the Commission is hereby approved.

ISSUED BY ORDER OF THE COMMISSION.
This the 11th day of September, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. SP-5436, SUB 1
DOCKET NO. E-22, SUB 559

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Verified Joint Notice and Request for Approval to Transfer the Certificate of Public Convenience and Necessity to Construct a 74.9-MW Solar Facility in Halifax County, North Carolina, from Chestnut Solar, LLC, to Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina	)))))))	ORDER APPROVING TRANSFER OF CERTIFICATE SUBJECT TO CONDITIONS

BY THE COMMISSION: On April 24, 2018, in Docket No. SP-5436, Sub 0, the Commission issued a certificate of public convenience and necessity (CPCN) to Chestnut Solar, LLC (Chestnut), for the construction of a 74.9-MW_{AC} solar photovoltaic electric generating facility in Halifax County, North Carolina.

On August 23, 2018, Chestnut and Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina (DENC) (collectively, the Applicants), filed a verified joint notice and request for approval (Joint Notice) to transfer the CPCN from Chestnut to DENC. DENC is an operating subsidiary of Dominion Energy, Inc.

The Applicants requested expedited approval of the transfer so that the Chestnut facility can achieve commercial operation under DENC's ownership while allowing sufficient time for the Chestnut facility to be constructed and construction milestones to be met in accordance with the Asset Purchase Agreement entered into between Chestnut and DENC.

According to the Joint Notice, DENC plans to acquire the Chestnut facility and its associated rights and assets. DENC plans to sell the entire energy output of Chestnut into the PJM Interconnection, L.L.C. (PJM) market and sell 100% of the Renewable Energy Certificates (RECs) and environmental attributes (EAs) to a third party customer (Customer) that is currently served by Virginia Electric and Power Company in its Virginia service territory.

Applicants stated that construction has not started on the Chestnut facility, and that interconnection service to the facility will be provided pursuant to an interconnection service agreement (ISA) previously entered into between and among PJM, Chestnut, and DENC. Applicants stated that the ISA was filed with the Federal Energy Regulatory Commission (FERC) on May 30, 2017, accepted by FERC on July 20, 2017, and allows for up to 74.9 MW of solar generation to be connected, which is expected to occur November 1, 2019.

In addition, Applicants stated that the original intent of Chestnut was to enter into a power purchase agreement with DENC or another buyer for sale of the output. DENC selected the Chestnut facility as the best option that would enable it to provide RECs and EAs to the Customer in a timely and economical manner. On August 3, 2018, the Applicants executed an Asset Purchase Agreement (APA) for the Chestnut facility and related assets. DENC will transfer 100%

of the RECs associated with Chestnut's output to the Customer. RECs will be tracked and retired using the PJM Environmental Information Services Generation Attribute Tracking System or other similar tracking system. DENC will not use the RECs associated with the Chestnut facility to comply with its own obligations under the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (REPS), nor will it use energy or RECs acquired for its own REPS compliance for the Customer.

Applicants stated that the electric output of the Chestnut facility will be sold into PJM under DENC's market-based rate authorization for wholesale sales of electric energy, and that DENC's purchase and operation of the Chestnut facility will not impact North Carolina customers, who will be held harmless from any costs associated with the Chestnut facility, as the Chestnut facility will be "ring fenced" so that none of its costs are included in DENC's rate base or cost of service for ratemaking purposes.Specifically, all costs incurred by DENC pursuant to the APA and Engineering, Procurement, and Construction Agreements, or in the potential provision of RECs and EAs to the Customer, will be directly assigned to the Customer through the rate it pays for the RECs and EAs. Further, DENC will directly assign or allocate costs and benefits as necessary to ensure that its North Carolina customers are in the same position they would have been had DENC not acquired the Chestnut facility or met the needs of the Customer as proposed.

The Public Staff presented this matter at the Commission's Regular Staff Conference on October 15, 2018. The Public Staff stated that it reviewed the Joint Notice and believes DENC's accounting procedures and internal controls can identify costs associated with the Chestnut facility and isolate these costs from the cost of serving DENC's North Carolina retail ratepayers, including costs in DENC's fuel rider. The Public Staff stated that these costs can be appropriately reviewed during the course of applicable ratemaking or other future proceedings.

Based on its review, the Public Staff concluded that the proposed transfer of the CPCN from Chestnut to DENC is justified by the public convenience and necessity and should be approved subject to certain conditions. The conditions are the same as those included in the Commission's Order Approving Transfer of Certificate Subject to Conditions for Pecan Solar, LLC, and Johannes Gutenberg Solar, LLC, issued on December 8, 2017, in Docket No. E-22, Sub 548. The Public Staff stated that the conditions are sufficient to ensure that DENC's North Carolina retail ratepayers will be held harmless from any costs associated with DENC's ownership and operation of Chestnut as proposed in the Joint Notice. The conditions recommended by the Public Staff to be imposed on the transfer of the certificate for the Chestnut facility are the following:

1. (Accounting Conditions) DENC shall utilize appropriate mechanisms in its accounting system and internal controls to identify, capture, and report all costs associated with the Chestnut facility in sufficient detail such that these costs are excluded from its North Carolina retail cost of service.

2. (Cost of Service Conditions) DENC shall allocate system level costs, including the costs associated with the Chestnut facility, to the Customer such that DENC's ownership and operation of the Chestnut facility will have no impact on the costs allocated to its North Carolina retail operations. This allocation procedure shall be used consistently in all DENC general rate

case and rider proceedings such that there will be no impact on DENC's North Carolina retail ratepayers as a result of DENC's ownership or operation of the Chestnut facility.

3. (Fuel Cost Conditions) DENC shall exclude from its fuel factor calculations any impacts of the Chestnut facility on total system energy volumes and system fuel costs such that DENC's ownership of the Chestnut facility will have no impact on its North Carolina retail fuel factors.

4. (REPS Conditions) DENC shall transfer all of the RECs earned by the Chestnut facility to the Customer, shall not apply the RECs associated with the Chestnut facility to its own REPS compliance obligation, and shall not seek to recover any costs associated with providing this service to the Customer from its North Carolina retail cost of service, including through its Rider RP and Rider RPE.

5. (Reporting Conditions) Upon commencing operation of the Chestnut facility, and annually thereafter, DENC shall file documentation in conjunction with its annual cost of service filings showing that DENC's North Carolina ratepayers are held harmless from any impacts resulting from DENC's ownership and operation of the Chestnut facility.

Based on the foregoing and the record in this matter, the Commission finds that the proposed transfer of the CPCN from Chestnut to DENC as proposed in the Joint Notice is justified by the public convenience and necessity and should be approved, subject to the conditions listed above.

IT IS, THEREFORE, ORDERED as follows:

1. That the transfer of the CPCN from Chestnut to DENC is approved.

2. That this approval is subject to Condition Nos. 1 through 5 as set forth above.

3. That DENC shall file a motion with the Commission informing the Commission of the date on which DENC's acquisition of the Chestnut facility is consummated and requesting a transfer of the CPCN to DENC.

ISSUED BY ORDER OF THE COMMISSION.
This the 16th day of October, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk Commissioner

Jerry C. Dockham did not participate in this decision.

TRANSPORTATION – COMMON CARRIER CERTIFICATE

DOCKET NO. T-4704, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Empire Moving and Storage Inc, 210 Loft Lane,	)	
Unit 127, Raleigh, North Carolina 27609 –	)	ORDER RULING ON
Application for Certificate of Exemption to	)	APPLICANT'S FITNESS
Transport Household Goods	)	

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 N. Salisbury Street, Raleigh, North Carolina, on Wednesday, May 23, 2018, at 10:00 a.m.

BEFORE: Commissioner Charlotte A. Mitchell, Presiding; Commissioners Jerry C. Dockham and Lyons Gray

APPEARANCES:

For Empire Moving and Storage Inc:

Fabio Ortiz, Esq., Fabio Ortiz Law Firm, PLLC, 1031 Dresser Court, Raleigh, North Carolina 27609

BY THE COMMISSION: On January 23, 2018, Empire Moving and Storage Inc (Empire or Applicant), filed an application with the Commission pursuant to G.S. 62-261.8(1) and Rule R2-8.1 of the Rules and Regulations of the North Carolina Utilities Commission for a certificate of exemption (certificate) to transport household goods by motor vehicle for compensation within North Carolina. The application named Edgar Joshua Brickley as the sole principal of the company.

On February 6, 2018, the certified criminal history record check for Edgar Joshua Brickley was filed with the Commission as required by G.S. 62-273.1 and Rule R2-8.1(a)(3).

On February 7, 2018, the protest deadline, established in accordance with Rule R2-8.1(c), passed without the Commission's receiving a protest.

On April 10, 2018, the Commission issued an Order Scheduling Application for Hearing on May 23, 2018, at 10:00 a.m., to address questions regarding the Applicant's application and fitness. The Order also provided that the Public Staff – North Carolina Utilities Commission (Public Staff) could participate in the hearing on behalf of the using and consuming public.

On May 10, 2018, Lucy Edmondson, Staff Attorney for the Public Staff, filed notice on behalf of the Public Staff to inform the Commission that the Public Staff would not participate in the hearing.

On May 23, 2018, the hearing was held in Raleigh, as scheduled. Mr. Brickley was represented before the Commission by counsel. Mr. Brickley is the Applicant's sole principal, appeared and testified in support of the application and responded to questions from the Commission. Mr. Brickley also offered testimony from his sister, Eugenia Grace Brickley, in support of the application.

Based upon the information contained in the application, the testimony received at the hearing, and the entire record in this matter, the Commission makes the following:

FINDINGS OF FACT

1. On January 23, 2018, Edgar Joshua Brickley, on behalf of Empire Moving and Storage Inc, filed an application with the Commission for a certificate to transport household goods by motor vehicle for compensation within North Carolina. Mr. Brickley is the sole principal of the business located in Raleigh, North Carolina. Mr. Brickley is properly before the Commission seeking a certificate pursuant to G.S. 62-261(8) and Rule R2-8.1 to transport household goods by motor vehicle for compensation within North Carolina.

2. The Commission regulates public utilities in the state of North Carolina, including household goods movers.

3. Mr. Brickley has worked with several companies since graduating from high school. He has worked for Prime Energy Group, Budget Movers Express, and D.H. Griffin Construction Company.

4. Mr. Brickley possesses more than ten years of moving experience. Most of his experience involves his work with Budget Movers Express.

5. Mr. Brickley has learned from his prior adverse experiences. Through his experiences, he learned that he needed to make improvements in his life so that he can be a better father to his son and become successful in his moving business.

6. Mr. Brickley has participated in several rehabilitation programs in an effort to improve his life.

7. Mr. Brickley incorporated Empire Moving and Storage Inc (Empire), in January 2018. Empire's office is located at 201 Loft Lane, Raleigh, North Carolina 27609.

8. Eugenia Grace Brickley is Edgar Joshua Brickley's younger sister. She testified at the hearing as a character witness in support of her brother's fitness and a certificate for Empire Moving and Storage.

9. Mr. Brickley has family support from his sister and adoptive parents.

10. Mr. Brickley is committed to operating Empire so that it is fully compliant and does not violate any laws and/or Commission rules.

DISCUSSION OF EVIDENCE AND CONCLUSIONS

On May 23, 2018, Mr. Brickley appeared before the Commission to address his fitness to engage in the business of moving households goods for compensation within the state of North Carolina. Based on the evidence of record, the Commission finds that he has satisfactorily answered questions regarding his experience in the moving industry, background, and overall fitness to receive a certificate.

Mr. Brickley has approximately ten years of experience in the moving business.[1] He obtained most of his moving experience while working with Budget Movers Express (Budget). According to Mr. Brickley, while employed by Budget, he moved one bedroom to three bedroom homes.[2] He performed most of the moves on the weekends. While at Budget, he learned how to drive a truck, pack customers' household goods, wrap furniture with blankets, and coordinate travel times so that the goods arrive safely.[3] Budget was primarily a part-time job for Mr. Brickley.

Mr. Brickley worked full-time for Prime Energy Group (Prime Energy), at or around the same time he worked part-time for Budget. Prime Energy is a spray foam installation company located in Raleigh, North Carolina.[4] As an employee of Prime Energy, Mr. Brickley interacted with potential customers, assisted customers in understanding the company's product, and made sure the customers were satisfied with the product.[5]

Finally, Mr. Brickley briefly worked for D.H. Griffin Construction Company (D.H. Griffin). He worked for D.H. Griffin for a year before the economy collapsed in 2008.[6] At D.H. Griffin, he did whatever the company needed him to do. His responsibilities ranged from plumbing to nailing.[7] He was eventually laid off due to the instability of the economy and the lack of work for the construction company.

After many years working for others and earning insufficient income, Mr. Brickley decided to start his own moving company. Mr. Brickley incorporated Empire Moving and Storage Inc (Empire), in January 2018.[8] Mr. Brickley believes that the income he earns from Empire can provide him with the opportunity to improve his life and allow him to care for his son. In preparation to begin operations, Empire has purchased a GMC box truck and rented a small office in which to conduct its business.[9] Empire has not yet performed any moves or hired a staff.[10]

[1] Transcript at 39, 46.
[2] Id. at 37.
[3] Id. at 45.
[4] Id. at 19.
[5] Id. at 28.
[6] Id. at 35.
[7] Id. at 50.
[8] Id. at 39.
[9] Id. at 40.
[10] Id.

The record shows that Mr. Brickley has matured from his adverse experiences in his past. His younger sister, Eugenia Grace Brickley, testified that she has noticed the maturation in her brother. She realizes that he has become more focused.[1] Ms. Brickley also testified that her brother is finally taking control of his life by applying for a certificate from the Commission.[2] She recognizes that this opportunity will allow her brother to better himself and the life of his son.[3] She testified that she realizes that her brother has now taken ownership of his potential success and has addressed his behavioral issues.[4]

Mr. Brickley attributes the change in his behavior to his willingness to seek assistance and help with his problems. He recognized that he has had some issues which he needed to address. He actively sought counseling and has participated in rehabilitation programs. He indicated that his involvement with these rehabilitation programs has had a positive impact on his efforts to move his life forward, so that he can become a more productive person.

Mr. Brickley testified that he is committed to making Empire successful by providing quality service to the using and consuming public. He also testified that he is committed to operating Empire so that it is fully compliant and does not violate any laws and/or Commission rules.[5] Empire is registered with the North Carolina Secretary of State and is current on its tax obligations to the North Carolina Department of Revenue.[6] Empire does not possesses a Federal Motor Carrier Number[7], which would allow it to perform intrastate moves.[8] At this time, however, Empire will only perform intrastate household goods moves within the state.

Mr. Brickley further testified that he understands that he is expected to work with customers to minimize the possibility of disputes and/or complaints about his service or broken household goods.[9] Mr. Brickley is confident that he can maintain a conflict free relationship with his customers. He informed the Commission that he has never had a problem or conflict with customers in any of his previous places of employment. He testified that he has never had any problems with any customers or co-workers.[10] In order to avoid conflicts with his customers, Mr. Brickley testified that will adopt the position to "always please the customer."[11]

The record shows that Mr. Brickley has a supportive family network. His sister supports his efforts to improve his life. His adoptive parents, who live and are employed in Raleigh, also provide important support for Mr. Brickley. Mr. Brickley is a single parent with a five year old

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1 Id. at 52.

2 Id. at 48.

3 Id.

4 Id.

5 Trans. at 29.

6 Id.

7 A federal motor carrier number authorizes the holder to perform interstate moves.

8 Trans. at 10.

9 Id. at 41.

10 Id. at 29.

11 Id.

son. His adoptive parents assist with his son's physical and educational needs.[1] The support from his adoptive parents has made it possible for him to pursue a certificate from the Commission.

Based upon the foregoing and the evidence of record, the Commission finds and concludes that Edgar Joshua Brickley has sufficiently addressed the Commission's questions regarding his fitness, willingness and ability to engage in the business of moving households goods for compensation within the state of North Carolina, has demonstrated reasonable and adequate knowledge of the households goods moving industry, has shown an ability and intent to follow the applicable statutes and Commission rules, and has demonstrated a commitment to provide satisfactory service to the using and consuming public. Therefore, the Commission concludes that his fitness **should not be** a basis for denying Empire Moving and Storage Inc, a certificate.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 23rd day of July, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

DOCKET NO. T-4704, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Empire Moving and Storage, Inc.,	)	
210 Loft Lane, Unit 127, Raleigh, North	)	ORDER GRANTING
Carolina, 27609 – Application for Certificate	)	CERTIFICATE OF EXEMPTION
of Exemption	)	

BY THE COMMISSION: On January 23, 2018, in the above-captioned docket, Empire Moving and Storage, Inc. (Applicant), pursuant to G.S. 62-261.8(1) and Commission Rule R2-8.1 filed an application with the Commission for a certificate of exemption. No protests were filed to the application. The application included the required confidential SBI and FBI criminal history records check.

On April 10, 2018, the Commission issued an Order Scheduling Application for Hearing to address questions regarding the Applicant's application and fitness.

On May 10, 2018, the Public Staff – North Carolina Utilities Commission notified the Commission that it did not intend to participate in the hearing.

[1] Id. at 20.

The hearing was held in Raleigh, North Carolina on Wednesday, May 23, 2018, as scheduled. The Applicant was represented by counsel. Mr. Brickley is the Applicant's sole principal, appeared and testified in support of the application, and responded to questions from the Commission. Applicant also offered testimony from his sister, Eugenia Grace Brickley, in support of the application.

On July 23, 2018, the Commission issued an Order Ruling on Applicant's Fitness concluding that the Applicant has shown to the satisfaction of the Commission that he possesses adequate knowledge of the household goods moving industry, an ability to follow the statutes and Commission rules, and a desire to provide satisfactory service to the using and consuming public.

Upon consideration of the application for a certificate of exemption filed with the Commission on January 23, 2018, the Commission's July 23, 2018 Order, and the entire record in this docket, the Commission finds and concludes that the Applicant should be granted a certificate of exemption to transport household goods, and has complied with the terms and conditions attached to the certificate of exemption:

1. Applicant is fit, willing, and able to properly perform the service of household goods transportation within North Carolina, is familiar with the moving industry, and has a reasonable and adequate knowledge of the rules and regulations governing the moving industry, including safety requirements as enforced by the North Carolina Division of Motor Vehicles.

2. Applicant will abide by the tariff requirements as established by the Commission and adopted in Maximum Rate Tariff No. 1.

3. Applicant is financially solvent and able to furnish adequate service on a continuing basis by maintaining the required insurance protection, maintaining safe, dependable equipment, and being able to settle any damage claims which may arise.

4. Applicant will maintain and has on file with the North Carolina Division of Motor Vehicles liability and cargo insurance coverage as required by law and Commission rules and regulations.

5. Applicant will maintain and has on file with the Commission's Operations Division a certificate of general liability insurance coverage in the minimum amount of $50,000.

IT IS, THEREFORE, ORDERED as follows:

1. That the application for certificate of exemption filed by Empire Moving and Storage, Inc., be, and the same is hereby, granted, and that the Applicant is hereby authorized to transport household goods between all points and places within North Carolina.

2. That the Applicant shall maintain its books and records in such a manner that all of the applicable items of information required in the prescribed Annual Report to the Commission can be used by the Applicant in the preparation of such Annual Report. A copy of the Annual Report form shall be furnished upon request made to the Public Staff – North Carolina Utilities Commission, Transportation Rates Division.

3. That the Applicant shall maintain its books and records in such a manner that all of the applicable items of information requested in its prescribed quarterly Public Utilities Regulatory Fee Report can be used by the Applicant in the preparation of such report and payment of quarterly regulatory fee. Any questions regarding the regulatory fee report and/or regulatory fee should be directed to the Commission's Fiscal Management Division at 919-733-5265.

4. That all vehicles, whether owned or leased, and used by the Applicant in its household goods operations must be identified with Applicant's name, city, state, and certificate of exemption number on both sides of each vehicle in letters not less than three (3) inches high. Such vehicles must also be identified with Applicant's certificate of exemption number on the left upper quadrant of the rear of each vehicle in letters not less than three (3) inches high.

5. That the Applicant shall attend a Maximum Rate Tariff (MRT) Seminar no later than three (3) months from the date of this Order.

6. That this Order shall constitute a certificate of exemption until formal Certificate of Exemption No. C-2900 has been issued and transmitted to the Applicant, along with a copy of Maximum Rate Tariff No. 1.

ISSUED BY ORDER OF THE COMMISSION.
This the 23rd day of July, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

DOCKET NO. T-4704, SUB 0
DOCKET NO. T-4704, SUB 1

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Empire Moving and Storage, Inc.,)
210 Loft Lane, Raleigh, North Carolina) ORDER APPROVING
27609 – Application for Sale and Transfer) SALE AND TRANSFER
of Certificate No. C-2900)

THE COMMISSION: On August 17, 2018, a joint application was filed, with the Commission, in the above-captioned dockets, by Mr. Fabio Ortiz, Esq., for and on behalf of Edgar Brickley, owner of Empire Moving and Storage, Inc., Raleigh, North Carolina, as transferee, and on behalf of Eugenia Brickley, purchaser of Empire Moving and Storage, Inc., Raleigh, North Carolina, as transferor, seeking authority to sell and transfer Certificate No. C-2900, together with the operating authority contained therein, from said transferor to said transferee.

No protests were filed to the application within the 15-day protest period and the required insurance filings in the name of Empire Moving and Storage, Inc., have been filed.

TRANSPORTATION – COMMON CARRIER CERTIFICATE

Upon consideration of the record in these dockets as a whole, the Commission finds and concludes, that the request for the sale and transfer of Certificate No. C-2900 should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That the application for the sale and transfer of Certificate No. C-2900, together with the operating authority contained therein, from Edgar Brickley, owner of Empire Moving and Storage, Inc., to Eugenia Brickley, purchaser of Empire Moving and Storage, Inc., be, and the same is hereby, approved.

2. That Empire Moving and Storage, Inc., shall maintain its books and records in such a manner that all of the applicable items of information required in the prescribed Annual Report to the Commission can be used in the preparation of such Annual Report. A copy of the Annual Report form shall be furnished upon request made to the Public Staff – North Carolina Utilities Commission, Transportation Rates Division at 919-733-7766.

3. Empire Moving and Storage, Inc., shall maintain its books and records in such a manner that all of the applicable items of information requested in its prescribed quarterly Public Utilities Regulatory Fee Report can be used in the preparation of such report and payment of the quarterly regulatory fee. Any questions regarding the regulatory fee report and/or regulatory fee should be directed to the Commission's Fiscal Management Division at 919-733-5265.

4. That all vehicles, whether owned or leased, and used by Empire Moving and Storage, Inc., in its household goods operations must be identified with Empire Moving and Storage, Inc.'s name, city, state, and certificate of exemption number on both sides of each vehicle in letters not less than three (3) inches high. Such vehicles must also be identified with Empire Moving and Storage, Inc.'s certificate of exemption number on the left upper quadrant of the rear of each vehicle in letters not less than three (3) inches high.

5. That Empire Moving and Storage, Inc., shall attend a Maximum Rate Tariff (MRT) seminar no later than three (3) months from the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 5th day of September, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

DOCKET NO. T-4149, SUB 11
DOCKET NO. T-4074, SUB 11
DOCKET NO. T-4657, SUB 5
DOCKET NO. T-4672, SUB 4
DOCKET NO. T-4710, SUB 2

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. T-4149, SUB 11 In the Matter of Proposal of SG of Raleigh, LLC, d/b/a All My Sons Moving & Storage of Raleigh to Use an Electronic Bill of Lading DOCKET NO. T-4074, SUB 11 In the Matter of Proposal of Bournias, LLC, d/b/a All My Sons Moving and Storage to Use an Electronic Bill of Lading DOCKET NO. T-4657, SUB 5 In the Matter of Proposal of All My Sons of South Raleigh, LLC, to Use an Electronic Bill of Lading DOCKET NO. T-4672, SUB 4 In the Matter of Proposal of All My Sons of Charlotte South, LLC, to Use an Electronic Bill of Lading DOCKET NO. T-4710, SUB 2 In the Matter of Proposal of All My Sons of Greensboro, LLC, to Use an Electronic Bill of Lading	ORDER APPROVING ELECTRONIC BILL OF LADING PROPOSAL

BY THE COMMISSION: On February 23, 2018, the Commission issued an Order Granting Petition Allowing Use of Electronic Bill of Lading and Adopting Procedure for Certificated Movers to Follow in Seeking Approval to Implement Electronic Bill of Lading for Their Specific Company in Docket Nos. T-4657, Sub 1 and T-100, Sub 49. Ordering Paragraph No. 2 of the Order instructed any Commission-certified household goods moving company seeking to use electronic bill of lading (BOL) to submit its proposal including its electronic document retention plan to the Transportation Division of the Public Staff. The Public Staff was requested to review each proposal and file a letter, memorandum, or comments recommending approval or disapproval with the Commission.

On March 23, 2018, SG of Raleigh, LLC, d/b/a All My Sons of Raleigh Moving & Storage (All My Sons of Raleigh) submitted its proposal to use an electronic BOL along with its electronic document retention plan to the Transportation Division of the Public Staff. All My Sons of Raleigh also requested approval of the same electronic BOL software on behalf of the following franchises: Bournias, LLC, d/b/a All My Sons Moving and Storage (Docket No. T-4074), All My Sons of South Raleigh, LLC, (Docket No. T-4657), All My Sons of Charlotte South, LLC, (Docket No. T-4672), and All My Sons of Greensboro, LLC (Docket No. T-4710). Each franchise would have its respective Commission-approved name appear on its electronic BOL.

On May 24, 2018, the Public Staff filed a letter concerning the March 23, 2018 electronic BOL proposal. The Public Staff concluded that the electronic BOL proposal submitted on behalf of the five All My Sons franchises satisfies the requirements for electronic BOLs as set out in the Commission's February 23, 2018 Order and recommended approval.

The Public Staff also recommended that if approval is granted, these five All My Sons franchises should be listed on Page 9-A of the MRT.

After careful consideration of the information provided and the recommendation of the Public Staff, the Commission finds good cause to grant approval of the electronic BOL proposal submitted by the five All My Sons franchises and therefore these five All My Sons franchises should be listed on Page 9-A of the MRT.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 31st day of May, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

WATER AND SEWER – CERTIFICATE

DOCKET NO. W-218, SUB 504

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Aqua North Carolina, Inc. for Approval of a Long-Term Debt Agreement and Refinancing of Debt Maturities Pursuant to G.S. 62-153, G.S. 62-161, and Commission Rule R1-16	)))))	ORDER APPROVING ISSUANCE OF PROMISSORY NOTE

BY THE COMMISSION: On June 25, 2018, Aqua North Carolina, Inc. (Aqua NC or Company) filed a verified Application pursuant to G.S. 62-153, G.S. 62-161, and Commission Rule R1-16 for authorization to issue additional debt in accordance with an unsecured note to Aqua America, Inc. (Aqua America or Parent), similar to the approvals issued by the Commission on: July 18, 2017, in Docket No. W-218, Sub 461; on November 13, 2015, in Docket No. W-218, Sub 422; on May 8, 2012, in Docket No. W-218, Sub 337; on June 18, 2009, in Docket No. W-218, Sub 297; and on December 21, 2010, in Docket No. W-218, Sub 320. In addition, the Company requests approval to refinance certain debt that will mature on December 31, 2018.

Based upon the verified Application and the Commission's entire files and records in this matter, the Commission now makes the following:

FINDINGS OF FACT

1. Aqua NC is a public utility operating in North Carolina providing water and wastewater utility service to the public for compensation. The Company provides utility service to approximately 80,300 water customers and approximately 18,500 wastewater customers in North Carolina under authority granted by the Commission.

2. The Company is a direct, wholly-owned subsidiary of Aqua America, a Pennsylvania corporation.

3. On July 18, 2017, the Commission approved Aqua NC's request in Docket No. W-218, Sub 461 to execute a note to Aqua America for long-term debt in the principal amount up to $85,968,398.

4. Aqua NC now proposes to add additional debt in an amount not to exceed $15,000,000, for an aggregate total pushdown debt balance of $100,968,398.

5. Pursuant to G.S. 62-153, G.S. 62-161, and Commission Rule R1-16, the Company requests approval to replace the earlier note that was the subject of Commission approval in Docket No. W-218, Sub 461 with the issuance of additional debt in the form of an unsecured note, as shown in *Exhibit A* to the Verified Application. The Company asserts that the proposed issuance (i) is for a lawful object within the corporate purposes of Aqua NC as a public utility; (ii) is compatible with the public interest; (iii) is necessary, appropriate for, and consistent with the proper performance by Aqua NC of its service to the public; (iv) will not impair Aqua NC's ability

to perform that service; and (v) is reasonably necessary and appropriate for the purposes for which it is issued.

6. In the event of Commission approval, Aqua America will cancel the promissory note in the amount of $85,968,398, which was approved in Docket No. W-218, Sub 461.

7. A provision in the Commission-approved note allows prepayment of the principal plus any outstanding interest. Thus, the debt can be paid off at any time during the term of the note without penalty. In addition, the interest rates in the note reflect the coupon rates with no adjustment for premiums or discounts. The debt was issued at par. A portion of the debt issuance costs related to Aqua NC debt will be amortized over the life of the loan by the Company. An estimate of the expenses associated with the transactions is attached to the Verified Application as *Exhibit B.*

8. The Company asserts that there are significant advantages to this approach. Aqua America is well-known in the financial markets and the costs of completing this transaction at the corporate level are less than they would be at the state level.

9. The Application submits that this debt issued by Aqua NC's parent company, Aqua America, is for the benefit of Aqua NC ratepayers and thus is compatible with the public interest. Aqua America can borrow debt at lower rates than its North Carolina subsidiary could if Aqua NC were to attempt to issue debt on its own as a "stand-alone" company. Aqua NC ratepayers directly benefit from the issuance of this note due to the lower interest rates afforded to the Parent. The result is a reduction in the overall weighted cost of debt in North Carolina.

10. The purpose of borrowing capital for North Carolina is to fund rate base additions, to maintain existing facilities, and to fund the working capital and investment capital requirements of Aqua NC. A listing of the relevant projects is attached to the verified Application as *Exhibit C.*

11. In addition to the Application to add debt to the Commission-approved note, the Company respectfully requests approval to refinance $4,158,634 of debt that will mature on or before December 31, 2018. The replacement debt results in a one hundred sixty-six (1.66%) basis point reduction compared to the weighted average interest rate of the maturing debt as shown in *Exhibit G.*

12. Certain terms of the note and provisions were summarized by Aqua NC as follows:

AGGREGATE PRINCIPAL AMOUNT:

The principal sum of up to one hundred million nine hundred sixty-eight thousand three hundred ninety-eight dollars and no cents ($100,968,398) in more than one separate series.

WATER AND SEWER – CERTIFICATE

AQUA NORTH CAROLINA, INC.

LONG-TERM DEBT SCHEDULE

Structure	Interest Rate	Issue Date	Maturity Date	Amount
Senior Unsecured Notes	3.41%	11/03/16	11/03/38	3,002,538
Senior Unsecured Notes	4.87%	07/31/03	07/31/20	4,860,925
Senior Unsecured Notes	4.87%	07/31/03	07/31/23	4,041,604
Senior Unsecured Notes	5.20%	02/03/05	02/03/20	2,800,586
Senior Unsecured Notes	5.63%	02/28/07	02/28/22	3,685,069
Senior Unsecured Notes	5.85%	02/28/07	02/28/37	3,299,664
Senior Unsecured Notes	5.40%	05/20/08	05/20/21	765,000
Senior Unsecured Notes	5.54%	12/27/06	12/31/18	2,210,263
Senior Unsecured Notes	4.72%	12/17/09	12/17/19	22,639,371
Senior Unsecured Notes	4.62%	06/24/10	06/24/21	1,100,000
Senior Unsecured Notes	4.83%	06/24/10	06/24/24	1,100,000
Senior Unsecured Notes	5.22%	06/24/10	06/24/28	11,450,836
Senior Unsecured Notes	3.57%	06/14/12	06/14/27	14,435,409
Senior Unsecured Notes	3.59%	05/20/15	05/20/30	11,631,300
Senior Unsecured Notes	3.57%	11/03/16	11/03/41	13,945,833
Total				100,968,398

13. The following Exhibits were appended to the verified Application and made a part thereof:

Exhibit A: Promissory Note between Aqua America and Aqua NC.
Exhibit B: Estimate of the expenses to be incurred in connection with the pledging of assets, the issuance and sale of securities, or the assumption of liabilities.
Exhibit C: Purpose or purposes to which the proceeds obtained are to be used.
Exhibit D: Aqua NC's balance sheet and income statements as of March 31, 2018.
Exhibit E: Please see the following link for Aqua America SEC filings: http://ir.aquaamerica.com/sec.cfm.
Exhibit F: Aqua NC's Cash Flow Statement for the Year Ended March 31, 2018.
Exhibit G: Debt Refinancing.
Exhibit H: Proposed Order Approving Verified Application for Approval of Long-Term Debt Agreement and Refinancing of Debt Maturities.

WHEREUPON, the Commission now reaches the following:

CONCLUSIONS

Based upon the foregoing Findings of Fact and the entire record in this proceeding, the Commission is of the opinion and so finds and concludes that the long-term debt transaction proposed herein:

- (i) Is for a lawful object within the corporate purposes of Aqua NC as a public utility;
- (ii) Is compatible with the public interest;
- (iii) Is necessary, appropriate for, and consistent with the proper performance by the Company of its service to the public as a utility;
- (iv) Will not impair Aqua NC's ability to perform its public utility service; and
- (v) Is reasonably necessary and appropriate for the purposes for which issued.

IT IS, THEREFORE, ORDERED that the verified Application filed by Aqua North Carolina, Inc. in this docket on June 25, 2018, is hereby approved and the Company is hereby authorized, empowered and permitted to: (1) make, execute and deliver to Aqua America a note for long-term debt in an amount not to exceed $100,968,398 principal amount; (2) refinance $4,158,634 of debt that will mature on or before December 31, 2018; and (3) take such actions as are reasonable and necessary to effectuate all transactions described in the Company's verified Application and Exhibits appended thereto.

IT IS FURTHER ORDERED that the Commission's approval in this docket does not restrict the Commission's regulatory authority to review and adjust, if the Commission deems it appropriate to do so, Aqua NC's cost of capital and/or expense levels for ratemaking purposes in the Company's next general rate case.

ISSUED BY ORDER OF THE COMMISSION
This 18th day of July, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. W-1274, SUB 5
DOCKET NO. W-1274, SUB 6

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. W-1274, SUB 5 In the Matter of Timothy F. Phelan, Post Office Box 598, Lake Junaluska, North Carolina 28745, Complainant v. Lake Junaluska Assembly, Inc., Respondent DOCKET NO. W-1274, SUB 6 In the Matter of Walt Logan, 1819 Follow Thru Road N, St. Petersburg, Florida 33710, Complainant v. Lake Junaluska Assembly, Inc., Respondent	ORDER RULING ON LAKE JUNALUSKA ASSEMBLY, INC., STATUS AS A PUBLIC UTILITY

BY THE COMMISSION: On October 11, 2017, Timothy F. Phelan (Complainant), filed a complaint with this Commission against Lake Junaluska Assembly, Inc. (Lake Junaluska), alleging that the organization is no longer eligible for exemption from Commission regulation and must file for a certificate of public convenience and necessity (CPCN). The complaint was assigned to Docket No. W-1274, Sub 5 and served on Lake Junaluska.

On October 18, 2017, Walt Logan (Complainant), filed a complaint with this Commission against Lake Junaluska alleging that the organization refuses to make available financial information regarding its operation of utility services and should no longer be exempt from Commission regulation. The complaint was assigned to Docket No. W-1274, Sub 6 and served on Lake Junaluska.

On October 24, 2017, Lake Junaluska, by and through counsel, filed a Motion to Consolidate Dockets and Extension of Time in the above-captioned proceedings.

On November 1, 2017, Lake Junaluska filed a response to the two complaints requesting that the Commission find that no adequate basis is established in the complaints sufficient to warrant revocation of the exemption from regulation previously granted by the Commission, but that Lake Junaluska be allowed to submit itself to regulation by the Commission with regard to its provision of water and wastewater services.

On November 2, 2017, the Commission issued an Order Consolidating Dockets for Disposition and Serving Response. Lake Junaluska's response was served on all parties including the Public Staff - North Carolina Utilities Commission (Public Staff) for further comment, if any.

On November 16, 2017, Complainant Phelan filed his reply agreeing with Lake Junaluska's decision to request that its water and wastewater services be regulated by the Commission. Mr. Phelan also states his belief that "there is a potential shortcoming in the current governance arrangements" of the water system and denies that "he or any other complainant oppose investments being made in the infrastructure."

On November 17, 2017, Complainant Logan filed his reply also agreeing that Lake Junaluska's grant of exemption from the Commission should be revoked. Mr. Logan, however, indicates that Lake Junaluska's response still fails to address the issue of providing residents the financial information that has previously been requested. He seeks a rate hearing in Waynesville, North Carolina, to determine if the current rates are appropriate or if adjustments are necessary.

The Commission has reviewed the entire record in these proceedings and finds that on December 19, 2007, the Commission issued an order granting an initial franchise to Southeastern Jurisdictional Administrative Council, Incorporated, d/b/a Lake Junaluska Assembly[1] to provide utility service for the Lake Junaluska Assembly in Haywood County and establishing rates. Lake Junaluska owns and operates the water distribution and wastewater collection systems and resells service provided by the Town of Waynesville to the residents of the Lake Junaluska Assembly community. Lake Junaluska currently provides water utility service to 860 customers and wastewater treatment service to 828 customers. Lake Junaluska, itself, was incorporated in 1938, but development of the community had begun in 1912. Lake Junaluska applied for the franchise in June 2007 at the behest of the North Carolina Department of Environment and Natural Resources, now the Department of Environmental Quality.

The Junaluska Assembly Community Council, created in 2005, establishes and approves the rates, terms and conditions on which water and wastewater services are furnished to Lake Junaluska customers. The Council is comprised of seven (7) residents elected from the Lake Junaluska Assembly community. Only residents of the Lake Junaluska Assembly community are eligible to be elected to the Council, and all persons receiving service from Lake Junaluska are eligible to vote in electing the members of the Council board. Many of the residents of the Lake Junaluska Assembly community were retired clergy or other individuals with professional or employment associations with the United Methodist Church. In recent years, the make-up of the community has changed as more and more property owners have no association with the United Methodist Church.

[1] Southeastern Jurisdictional Administrative Council, Incorporated, subsequently merged with and into Lake Junaluska Assembly, Incorporated, in 2008.

WATER AND SEWER – COMPLAINT

On June 23, 2009, Lake Junaluska filed a petition in Docket No. W-1274, Sub 4 for exemption from regulation pursuant to G.S. 110.5, which states:

> The Commission may exempt any water or sewer utilities owned by nonprofit membership or consumer-owned corporations from regulation under this Chapter, subject to those conditions the Commission deems appropriate, if:
> (1) The members or consumer-owners of the corporation elect the governing board of the corporation pursuant to the corporation's articles of incorporation and bylaws; and
> (2) The Commission finds that the organization and the quality of service of the utility are adequate to protect the public interest to the extent that additional regulation is not required by the public convenience and necessity.

In its petition, Lake Junaluska argued:

> The structure of [Lake Junaluska] and the [Council], all within the sphere of the United Methodist Church, is such that the Lake Junaluska Assembly community, through the [Council], meets the requirements of G.S. 62-110.5. The Commission should exempt [Lake Junaluska] from regulation under Chapter 62, subject to any reasonable condition the Commission deems appropriate.
>
> [Lake Junaluska] is operating efficiently and the residents of the Lake Junaluska Assembly community elect the [Council] Board pursuant to its Constitution and By-laws. [Lake Junaluska] is willing to accept such any reasonable condition the Commission deems appropriate, including that [Lake Junaluska's] request for exemption from regulation be granted subject to revocation if, after notice and an opportunity to be heard, the Commission finds that circumstances have changed to the extent that the public convenience and necessity require regulation in order to protect the public interest. ...
>
> The organizational structure described above, and the quality of services provided by [Lake Junaluska], and [Lake Junaluska's] goal of giving "oversight and care to the Lake Junaluska Campus [and] Residential Community" are adequate to protect the public interest to the extent that additional regulation is not now required by the public convenience and necessity.

On August 18, 2011, on the basis of the above representations, the recommendation of the Public Staff, and the lack of complaint by any customers, Lake Junaluska was granted the requested exemption from regulation as the Commission found that Lake Junaluska met the requirements for its provision of water and wastewater to be exempted from regulation pursuant to G.S. 62-110.5.

A number of residents in the Lake Junaluska Assembly community have since voiced concerns regarding the management and operation of the water and wastewater systems. Lake Junaluska has historically experienced problems accounting for the water which it purchases. Lake Junaluska attributes its water related problems with the age of the system and the need for improvements in the infrastructure. The complaints recently filed with the Commission concern the operation of the Council in setting the rates for water and wastewater service provided to the

Lake Junaluska Assembly community. The complaints challenge Lake Junaluska's operation of the utility service and request that the Commission revoke the exemption from regulation. These complaints [IMPLICITLY] call into question whether "the organization and the quality of service of the utility are adequate to protect the public interest" and justify the exemption from regulation granted pursuant to G.S. 62-110.5. After reviewing the complaints filed with the Commission, Lake Junaluska, although disputing the merits of the complaints filed against it, consents to the Commission's regulation of its water and wastewater services and agrees to file a CPCN.

Based on the foregoing, the Commission finds and concludes that the organization and the quality of service of the utility are no longer adequate to protect the public interest that the exemption granted to Lake Junaluska's in Docket No. W-1274, Sub 4 on August 18, 2011, should be revoked, and that the public utility should again be regulated by the Commission. Lake Junaluska shall have 120 days within which to file an application with the Commission for a CPCN. The Commission finds and concludes that because Lake Junaluska consents to be subject to Commission regulation and agrees to file an application for a CPCN, a hearing is not necessary in this matter. Finally, the Commission finds and concludes that while Lake Junaluska's application for a CPCN is pending no customer should be disconnected without prior approval from the Commission.

IT IS, THEREFORE, ORDERED as follows:

1. That the exemption granted to Lake Junaluska in Docket No. W-1274, Sub 4 on August 18, 2011, is hereby revoked;

2. That Lake Junaluska is a water and wastewater public utility subject to regulation by the Commission;

3. That Lake Junaluska shall file an application for a CPCN with the Commission within 120 days of the date of this Order;

4. That Lake Junaluska shall not discontinue water and/or wastewater service to any current customers while its CPCN application is pending without prior approval of the Commission; and

5. That this Order shall be served on Complainants and Respondent by both electronic mail (email), delivery confirmation requested and United States certified mail, return receipt requested and on the Public Staff by email, delivery confirmation requested.

ISSUED BY ORDER OF THE COMMISSION.
This the 23rd day of April, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

WATER AND SEWER – COMPLAINT

DOCKET NO. W-1316, SUB 0
DOCKET NO. W-1316, SUB 1
DOCKET NO. W-1316, SUB 2

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. W-1316, SUB 0 In the Matter of Fred and Vonis Waugh, 8355 Brookfield Road, Connelly Springs, North Carolina 28612, Complainants v. Pine Mountain Property Owners Association, Inc., Respondent DOCKET NO. W-1316, SUB 1 In the Matter of Burke Mountain Southeast, LLC, Complainant v. Pine Mountain Property Owners Association, Inc., Respondent DOCKET NO. W-1316, SUB 2 In the Matter of Keith and Linda Shifflett, 8550 Faraway Drive, Connelly Springs, North Carolina 28612, Complainants v. Pine Mountain Property Owners Association, Inc., Respondent	ORDER RULING ON PINE MOUNTAIN PROPERTY OWNERS' ASSOCIATION, INC., STATUS AS A PUBLIC UTILITY

BY THE COMMISSION: On April 12, 2017, the Commission issued an Order Consolidating Dockets and Requesting that the Public Staff conduct an investigation in the above-captioned proceedings.

After conducting an investigation of the issues, including interviewing the involved parties, inspecting the utility's assets and learning of the utility's initial service plans, on May 25, 2017, the Public Staff filed with the Commission its Investigation Report and Recommendations. The Public Staff reports that the Pine Mountain Property Owners' Association, Inc. (POA), provides water and wastewater utility service for compensation to commercial customers who are not POA members, namely, the Gateway Mountain Springs Chapel and Conference Center (including the restaurant) and the Second Tee (formerly the Developer's sales office). In addition, the POA provides water utility service for compensation to a residential customer in Cleveland County who is not a POA member. The Public Staff recommends: 1) that the Commission issue an Order finding that the POA is a water and wastewater public utility subject to regulation by the Commission and requiring the POA to file an application for a certificate of public convenience and necessity (CPCN) within 120 days of the Commission Order; and 2) that the Commission issue an interim Order stating the POA shall not discontinue water and/or wastewater service to any current customers pending the Commission's Order finding the POA is a public utility subject to regulation by the Commission.

On May 26, 2017, the Commission issued an Order Serving the Public Staff's Report and Recommendations Requesting Comments from the Parties.

On June 21, 2017, Complainants Fred and Vonis Waugh, owners of the Gateway Mountain Springs Chapel and Conference Center, filed comments with the Commission requesting that the Commission accept the Public Staff's recommendations.

On June 30, 2017, Complainants Ray Hollowell and Burke Mountain Southeast, LLC, filed comments with the Commission also agreeing with the Public Staff's recommendations and requesting that the Commission act on the Public Staff's recommendations.

On July 14, 2017, the Commission issued an Order Serving Complainants' Comments to Respondent.

On July 20, 2017, Respondent POA filed its Response to the Public Staff's Investigation Report and Recommendations. In its Response, POA does not contest the Public Staff's conclusion that the POA is a public utility pursuant to G.S. 62-3(23)a.2, as the POA provides water and wastewater utility service for compensation to the commercial customers not POA members. In addition, the POA provides water utility service for compensation to a residential customer not a POA member in Cleveland County.

Additionally, the POA concurs with the Public Staff's recommendation and agrees that the Commission should issue an Order or Orders in these dockets:

(a) finding that the POA concurs with the recommendations of the Public Staff and agrees that the Commission should issue an Order or Orders in these dockets consistent with the findings made by the Public Staff including that the POA is a water and wastewater public utility required to be regulated by the Commission;

(b) requiring the POA to file an application for a CPCN within 120 days of the date of the Commission Order; and

(c) stating, by interim Order, that the POA shall not discontinue water and/or wastewater service to any current customers pending the Commission's Order finding that the POA is a public utility subject to regulation by the Commission.

On July 26, 2017, the Commission issued an Order Serving POA's Response to the Public Staff's Investigation Report and Recommendations.

The Commission has reviewed the record, including all the pleadings submitted by the parties and finds and concludes that the POA is a public utility pursuant to G.S. 62-3(23)a.2 since the POA provides water and/or wastewater utility service for compensation to customers that not POA members. The Commission further finds and concludes that the POA agrees with and adopts the recommendations set forth by the Public Staff in its Investigation Report filed with the Commission on May 25, 2017. None of the Complainants oppose the Public Staff's findings and POA's intention to accept the Public Staff's recommendations. Finally, the Commission finds and concludes that because the POA consents that it is a public utility and agrees to file an application for a CPCN there is no need for a hearing in this matter.

IT IS, THEREFORE, ORDERED as follows:

1. That the POA is a water and wastewater public utility subject to regulation by the Commission;

2. That POA shall file with the Commission an application for a Certificate of Public Convenience and Necessity within 120 days of the date of this Order;

3. That the POA shall not discontinue water and/or wastewater service to any current customers pending the POA filing an application for a CPCN from the Commission; and

4. That this Order shall be served on Complainants and Respondent by both electronic mail (email), delivery confirmation requested and United States certified mail, return receipt requested and on the Public Staff by email, delivery confirmation requested.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of February, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

DOCKET NO. W-864, SUB 14
DOCKET NO. W-1314, SUB 1

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. W-864, SUB 14 In the Matter of Complaint and Petition by Public Staff for Revocation of Franchise of Webb Creek Water and Sewage, Inc. DOCKET NO. W-1314, SUB 1 In the Matter of Application of Pluris Webb Creek, LLC, for a Certificate of Public Convenience and Necessity to Provide Sewer Utility Service in the Areas Presently Served by Webb Creek Water and Sewage, Inc. in Onslow County, North Carolina.	)	ORDER RESCINDING ORDER REQUIRING THE FILING OF A JOINT PROPOSED ORDER AUTHORIZING PLURIS TO PROVIDE TEMPORARY WASTEWATER UTILITY SERVICE TO THE PINES MOBILE HOME PARK

BY THE PRESIDING COMMISSIONER: On June 7, 2017, in Docket No. W-864, Sub 14, the Public Staff – North Carolina Utilities Commission (Public Staff) filed a Complaint and Petition for Revocation (Petition for Revocation) of Franchise for Webb Creek Water and Sewage, Inc. (Webb Creek), for the Webb Creek wastewater utility system in Onslow County, North Carolina. In support of its Petition for Revocation, the Public Staff stated the franchise should be revoked pursuant to G.S. 62-112(b), due to the willful failure of Webb Creek to comply with provisions of the Public Utilities Act Chapter 62, and the Rules and Regulations of the Commission.

On July 31, 2017, the Commission issued an Order Scheduling Hearing and Requiring Notice. (Order). In the Order, the Commission scheduled an evidentiary hearing on the Public Staff's Petition for Revocation on September 6, 2017, at 9:30 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina.

On that date and at that time the Commission convened the evidentiary hearing and received evidence from the Public Staff as to the grounds that Webb Creek's certificate should be revoked. During the hearing, the Public Staff indicated that, the Commission-appointed emergency operator for the Webb Creek wastewater system,[1] Pluris Webb Creek, LLC (Pluris), had filed, on June 13, 2017, in Docket No. W-1314, Sub 1, an Application for a Certificate of Public Convenience and Necessity (CPCN Application), which if granted, would authorize it to provide sewer utility service in its own right in the current territory served by Webb Creek. After receiving

[1] On August 8, 2016, in Docket No. W-864, Sub 11, the Commission issued an Order Appointing Emergency Operator, Approving Increased Rates, and Requiring Customer Notice.

said evidence, however, the Commission suspended the revocation hearing and ordered that the Petition for Revocation be rescheduled in conjunction with a hearing which was yet to be scheduled for Pluris' CPCN Application because of the Commission's concern that there were certain overlapping issues between the Petition for Revocation and the CPCN Application. Based upon the aforementioned, the Presiding Commissioner found that good cause existed to reconvene the Revocation Hearing in Docket No. W-864, Sub 14, and to schedule said hearing in conjunction with an evidentiary hearing on the CPCN Application in Docket No. W-1314, Sub 1. Further, the Presiding Commissioner found that good cause existed to schedule both hearings on Thursday, December 7, 2017, at 9:30 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina. The Commission thereafter issued an Order Reconvening Hearing, Scheduling Hearing and Requiring Notice (the Order Reconvening Hearing). The Order Reconvening Hearing required:

> 5. That a copy of this Order shall be mailed with sufficient postage or shall be hand delivered by Pluris, the Webb Creek Emergency [Operator], to all customers served by Webb Creek within five business days following the date of this Order. Further that Pluris shall submit the Attached Certificate of Service to the Commission, properly signed and notarized, within seven days of completing such requirement.
>
> 6. That a copy of this Order shall be mailed by the Public Staff, certified mail and by first class mail with sufficient postage, no later than the five business days after the issuance of this Order, to:
>
> Mr. J. Hal Kinlaw, Jr. (#62496-056)
> Registered Agent for Webb Creek Water and Sewage, Inc.
> FCI Ashland
> Post Office Box 6001
> Ashland, KY 41105

On November 22, 2017, in accordance with the provisions of the Order Reconvening Hearing, the Public Staff prefiled the testimony of James Gregson, Interim Director, Division of Water Resources, Department of Environmental Quality, and Charles Junis, P.E., Utilities Engineer, Public Staff, Water, Sewer, and Communications Division. Also, on that date and in accordance with the provisions of the Order Reconvening Hearing, Pluris prefiled the testimony of Maurice Gallarda, the Managing Member of Pluris Holdings, LLC.

On November 27, 2017, the Commission began evidentiary hearings in Docket No. E-2, Sub 1142, in the Matter of the Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina (DEP Rate Hearing). Because the DEP Rate Hearing was expected to carry over into and through the week of December 4, 2017, the Presiding Commissioner found that good cause existed to cancel the December 7, 2017 hearings in these matters and reschedule those hearings on Monday, January 8, 2018, at 1:30 p.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina. By Order dated December 4, 2017, the Commission issued an Order Cancelling Hearings on December 7, 2017 and Rescheduling Those Hearings on January 8, 2018. The Rescheduling Order required:

> 3. That a copy of this Order shall be mailed with sufficient postage or shall be hand delivered by Pluris, the Webb Creek Emergency [Operator], to all customers served by Webb Creek within five business days following the date of this Order. Further that Pluris shall submit the Attached Certificate of Service to the Commission, properly signed and notarized, within seven days of completing such requirement.
>
> 4. That a copy of this Order shall be mailed by the Public Staff, certified mail and by first class mail with sufficient postage, no later than the five business days after the issuance of this Order, to:
>
> Mr. J. Hal Kinlaw, Jr. (#62496-056)
> Registered Agent for Webb Creek Water and Sewage, Inc.
> FCI Ashland
> Post Office Box 6001
> Ashland, KY 41105

On December 22, 2017, pursuant to G.S. 62-116(a), Pluris filed a Supplemental Request to its CPCN Application (Supplemental Request) for authority to also serve Pines Mobile Home Park (Pines MHP). In support of the Supplemental Request, Pluris indicated it was requesting a CPCN to serve the Pines MHP, an area currently being served by Pines Utilities, Inc. pursuant to a CPCN issued in Docket No. W-822 Sub 0, and attached a map of the portion of The Pines Development[1] which is the subject of the Supplemental Request. Further, Pluris indicated that the Pines MHP was located outside of the Webb Creek service area.

On January 5, 2018, the Public Staff filed the testimony of Windley E. Henry, Accounting Manager of the Water, Sewer, and Communications Section, Accounting Division, and the supplemental testimony of Charles Junis, which addressed, in part, the Supplemental Request. Also, on that date, Pluris filed the supplemental testimony of Maurice Gallarda in support of the Supplemental Request to serve the Pines MHP.

On January 8, 2018, the Commission convened the hearings as scheduled. The aforementioned evidence was presented and received from the Public Staff and Pluris. Neither Webb Creek nor Mr. Kinlaw was present. Neither presented any testimony or evidence. At the conclusion of the hearing, the Presiding Commissioner, among other things, directed the Pluris and the Public Staff to file a joint proposed order by January 19, 2018, allowing Pluris to provide temporary service to the Pines MHP and approving rates. This Order was in error and shall and must be rescinded for the following reasons.

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[1] The Pines Development in Onslow County, North Carolina consists of the Pines MHP with 170 units, 34 existing single-family residences in areas known as Eastport I and Timber Ridge, Section III-B&C, and other lots to be developed as single-family residences. The next phase of the Pines Development will consist of 44 new homes in Eastport Section III, Phase 1.

G.S. 62-116(a) provides in pertinent part, that "[u]pon the filing of an application in good faith for a franchise, the Commission may in its discretion, after notice by regular mail to all parties holding franchises authorizing similar services within the same territory and upon a finding that no other adequate existing service is available, pending its final decision on the application, issue to the applicant appropriate temporary authority to operate under such just and reasonable conditions and limitations as the Commission deems necessary or desirable to impose in the public interest[.]" By the clear terms of the statute, the Commission does not acquire jurisdiction to issue an order authorizing Pluris to provide temporary service to Pines MHP unless a good faith application has been filed requesting that it be allowed to provide such service in that specific territory. No such application has been filed in Docket No. W-1314, Sub 1.

As noted above, in its pleading Pluris requested that the Commission allow it to supplement its CPCN application that it has filed in this docket and add the service territory that it now requests.[1] Assuming arguendo that the Commission was inclined to do so, the Commission would nevertheless be precluded from issuing the order herein requested because the Commission has not satisfied the statutory and constitutional requirements that notice be provided to the customers in Pines MHP and to PUI[2], nor has the Commission satisfied the constitutional requirement that Pine Utilities, Inc. be given the opportunity to be heard before the Commission concerning the matter of allowing Pluris to serve customers that Pines Utilities, Inc. is obligated to serve pursuant to its CPCN. See G.S. 62-42.

In its supplemental testimony filed on January 5, 2018, Pluris indicated that on January 3, 2018, Pluris entered into a Utility Asset Purchase Agreement with PUI wherein those parties agreed, subject to Commission approval and certain other conditions, that Pluris would acquire all of PUI's utility assets and franchise. Before the Commission can act on any matters affecting PUI, Pluris is required to file with the Commission a transfer application with PUI designating the specific territory that it will be serving after the acquisition and requesting approval of rates. Pluris cannot, as it has attempted to do here, attach an unrelated request for temporary operating authority to serve the Pines MHP to Docket No. W-1314, Sub 1, an application for a CPCN to provide sewer utility service to customers in the existing Webb Creek service area. The Commission understands that Pluris plans to serve or is presently serving PUI's customers in the Pines MHP with Webb Creek's existing wastewater treatment plant. Further, based upon the testimony received in these dockets, the Commission is aware that Pluris hopes to build a new membrane bio-reactor (MBR) wastewater plant in the future to provide wastewater utility service to the Webb Creek and the

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[1] The Commission's CPCN application permits Pluris to request Commission authority to serve multiple subdivisions or service areas in one application. However, in order for the Commission to authorize such service pursuant to a single application, the Applicant must list "each subdivision or service area" in which authorization is being requested by the Applicant in the application. See Commission Form Revised 6/04: Application for a Certificate of Public Convenience & Necessity and For Approval of Rates. See also, Commission Form Revised 6/04: Application for Transfer of Public Utility Franchise and for Approval of Rates which has the same requirements. In Pluris' CPCN application form filed in this proceeding, Pluris only lists "Webb Creek (existing)" as the subdivision or service area for which it is requesting permission to serve. Pines MHP is not listed in the application as a requested service area.

[2] Because the CPCN application indicated that Pluris would only serve customers in the Webb Creek service, notice of these hearings was only provided to Webb Creek customers and Webb Creek. No notice was provided to the Pines MHP customers or PUI.

Pines MHP service areas, as well as, other portions of The Pines Development service area.[1] However, the Commission is of the opinion, and therefore finds and concludes that with respect to Pluris' Supplemental Request, proper procedure must be followed.

Thus, for the reasons set forth herein, the Order directing Pluris and the Public Staff to file a joint proposed order authorizing Pluris to provide temporary service to the Pines MHP was issued in error. The Order is hereby rescinded.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the __1st__ day of February, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. W-864, SUB 14
DOCKET NO. W-1314, SUB 1

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. W-864, SUB 14 In the Matter of Complaint and Petition by Public Staff for Revocation of Franchise of Webb Creek Water and Sewage, Inc. DOCKET NO. W-1314, SUB 1 In the Matter of Application of Pluris Webb Creek, LLC, for a Certificate of Public Convenience and Necessity to Provide Sewer Utility Service in the Service Areas Presently Served by Webb Creek Water and Sewage, Inc., in Onslow County, North Carolina	)	ORDER REQUIRING SPECIFIC CONDITIONS TO BE SATISFIED CONCERNING THE GRANTING OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO PLURIS WEBB CREEK, LLC

[1] Pluris has previously sought and received Commission permission to provide temporary service to customers in a portion of The Pines Development. See Docket No. W-1314, Sub 0. In that instance, Pluris filed a separate CPCN application designating the specific service area requested, the matter was scheduled for a public hearing, subject to cancellation if no significant protests were received, and customer notice was provided.

WATER AND SEWER – COMPLAINT

HEARD: Wednesday, September 6, 2017, at 9:30 a.m. and Monday, January 8, 2018, at 9:30 a.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina 27603

BEFORE: Commissioner Daniel G. Clodfelter, Presiding, Commissioner ToNola D. Brown-Bland and Commissioner James G. Patterson

APPEARANCES:

For the Using and Consuming Public:

William Grantmyre, Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

For Pluris Webb Creek, LLC:

Daniel C. Higgins, Burns, Day & Presnell, P.A., PO Box 10867, Raleigh, North Carolina 27605

BY THE COMMISSION: On June 7, 2017, the Public Staff filed a Complaint and Petition for Revocation of Franchise in Docket No. W-864, Sub 14 requesting that the Commission revoke the franchise and certificate of public convenience and necessity (CPCN) previously issued to Webb Creek Water and Sewage, Inc. (Webb Creek).

After the Public Staff filed its Petition for Revocation, Pluris Webb Creek, LLC (Pluris) subsequently filed an Application, in Docket No. W-1314, Sub 1, requesting that Pluris be issued a certificate of public convenience and necessity authorizing it to serve the Webb Creek service area, if the Commission grants the Public Staff's request and revokes Webb Creek's CPCN and franchise.

On July 31, 2017, the Commission issued its Order Scheduling Hearing and Requiring Notice in Docket No. W-864, Sub 14, relating to the Public Staff's Complaint and Petition for Revocation. That Order required that the Public Staff serve a copy of that Order, by certified mail and first class mail with sufficient postage, no later than the next business day after the issuance of that Order, on Webb Creek's Registered Agent addressed as follows:

Mr. J. Hal Kinlaw, Jr. (#62496-056)
Registered Agent for Webb Creek Water and Sewage, Inc.
FCI Ashland
Post Office Box 6001
Ashland, Kentucky 41105

Pursuant to that Order, on August 17, 2017, the Public Staff also filed the testimony and exhibits of Charles M. Junis, Utilities Engineer, Water, Sewer, and Communications Division. The Public Staff filed its Exhibit 1 on August 31, 2017, certifying service of that Order on Webb Creek's Registered Agent.

On September 6, 2017, the Petition for Revocation came on for hearing as scheduled. No one appeared on behalf of Webb Creek when the matter was called for hearing on that date. The Public Staff presented the testimony of Public Staff witness Junis. Because there is a logical relationship between the relief requested in the Public Staff's Petition for Revocation and Pluris' Application for issuance of a CPCN in Docket No. W-1314, Sub 1, after hearing the testimony of witness Junis, the Commission recessed the hearing and ordered that it be resumed at a later date when the Commission would also take up Pluris' Application for a CPCN.

On October 31, 2017, the Commission issued its Order Reconvening Hearing, Scheduling Hearing, and Requiring Notice. Pursuant to that Order, on November 22, 2017, the Public Staff filed the supplemental testimony of Charles M. Junis and the testimony of James Gregson, Interim Deputy Director, Division of Water Resources, North Carolina Department of Environmental Quality. Also pursuant to that Order, on November 22, 2017, Pluris filed the testimony of Maurice Gallarda, P.E., Managing Member.

On December 4, 2017, the Commission issued its Order Cancelling Hearings on December 7, 2017, and Rescheduling Those Hearings on January 8, 2018. On December 13, 2017, Pluris filed its Certificate of Service reflecting that it had served the Commission's December 4, 2017 Order.

On December 22, 2017, Pluris supplemented its Application in Docket No. W-1314, Sub 1, to also request that Pluris be granted a CPCN and temporary operating authority pursuant to G.S. 62-116, for provision of wastewater utility service to the Pines Mobile Home Park (Pines MHP), which is part of The Pines Development in Onslow County, and for approval of rates (Pluris Supplemental Application). On January 5, 2018, Pluris filed the supplemental testimony of Maurice Gallarda in support of its supplemental request for authority to serve the Pines MHP.

On January 5, 2018, the Public Staff filed the supplemental testimony of Charles M. Junis and the testimony and exhibits of Windley E. Henry, Accounting Manager, Water/Communications Section, Accounting Division. On January 5, 2018, the Public Staff also filed its Exhibit 1 to the previously filed testimony of James Gregson.

The Public Staff's Petition for Revocation and Pluris' Application for a CPCN authorizing it to serve the Webb Creek service area came on for hearing as scheduled on January 8, 2018, at which time the Commission consolidated Docket No. W-864, Sub 14 with Docket No. W-1314, Sub 1. No representative appeared on behalf of Webb Creek when these matters were called for hearing on that date.

At the conclusion of the hearing, the Presiding Commissioner, among other things, directed that Pluris and the Public Staff: (1) file a joint proposed order by January 19, 2018 allowing Pluris to provide temporary service to the Pines MHP and (2) to file briefs and proposed orders concerning Public Staff's Petition for Revocation of Webb Creek's CPCN and Pluris' Application for issuance of a CPCN within 30 days of the date of the hearing. The Commission extended the time to file the latter proposed order until February 14, 2018.

On January 19, 2018, Pluris and the Public Staff filed a Joint Proposed Order Approving Temporary Operating Authority, Approving Interim Rates, Requiring Undertaking and Requiring Customer Notice (Proposed Temporary Operating Authority Order).

On February 1, 2018, the Presiding Commissioner issued an Order Rescinding Order Requiring the Filing of a Joint Proposed Order Authorizing Pluris to Provide Temporary Service to the Pines Mobile Home Park (Rescission Order). In the Rescission Order, the Presiding Commissioner held that the Commission did not have jurisdiction to issue an order authorizing Pluris to provide temporary service to the Pines MHP in either docket that was the subject of the hearing because an application requesting such relief had not been filed with the Commission and because the Commission had not satisfied statutory and constitutional requirements that Pine Utilities, Inc. (PUI), the Commission-certificated provider of sewer utility service in the Pines MHP be given the opportunity to be heard before the Commission took such action. [1]

On February 14, 2018, the Public Staff and Pluris filed a Joint Proposed Order concerning the Public Staff's Petition for Revocation of Webb Creek's CPCN and Pluris' Application for issuance of a CPCN.

Based upon the foregoing and the entire record in this matter, the Commission makes the following

FINDINGS OF FACT

General Matters

1. Webb Creek Water and Sewage, Inc. is a North Carolina corporation. By Order issued January 14, 1987, in Docket No. W-864, the Commission granted a certificate of public convenience and necessity to Webb Creek authorizing it to provide wastewater utility service in the South Queens Creek Subdivision in Onslow County. By Order dated September 4, 1987, in Docket No. W-864, Sub 2, the Commission recognized that the name of Queens Creek Subdivision had been changed to Fox Trace, and reissued the CPCN in the name of Fox Trace Subdivision.

2. Since the issuance of that CPCN, Webb Creek has extended its service to other adjoining developments. The subdivisions currently served by the Webb Creek system include:

Buckhead
Creekertown
Creekertown Villas
Cooper's Court
Foxden
Foxlair
Fox Trace Sections I, II, and III

[1] On February 12, 2018, Pluris and PUI filed an Application for Transfer of Franchise and Approval of Rates in Docket Nos. W-822, Sub 3 and W-1314, Sub 2.

Fox Trace Section IV, Phases 1 through 6
Fox Trace Section V
Fox Trace Point I and II
Jack's Branch
Jack's Branch Townhomes
Quail Roost

3. The Webb Creek wastewater treatment plant (WWTP) is an aged (30+ years old) 300,000 GPD sequencing batch reactor (SBR) wastewater treatment plant. The Webb Creek wastewater collection system consists of approximately 11.9 miles of gravity sewer, approximately 2.6 miles of force main, approximately 0.25 miles of pressure sewer, three simplex pump stations that discharge to a pressure sewer, and eight duplex pump stations.

4. The Webb Creek wastewater utility system has plant capacity to serve approximately 1,800 residential customers, Sand Ridge Elementary School, and six other commercial customers. There are currently approximately 1,070 residential customers and seven commercial customers, including the Sand Ridge Elementary School, in the Webb Creek service area.

Public Staff's Complaint and Petition for Revocation

5. Webb Creek has or had certain permits issued by the North Carolina Department of Environmental Quality (DEQ), formerly the North Carolina Department of Natural Resources (DENR), including a Collection Permit and a National Pollutant Discharge Elimination System (NPDES) permit. The NPDES Permit (Permit NC0062642), issued to Webb Creek by DENR allowing Webb Creek to discharge treated wastewater from its WWTP to Wallace Creek. That NPDES permit expired on June 30, 2017.

6. There have been numerous problems and issues with the operations, assets, equipment, and management of the Webb Creek system. Due to material non-compliance with G.S. 143-215.1, the NPDES Permit, and the Collection Permit, as of August 2016, Webb Creek had been issued over 500 Notices of Violation by DEQ's Division of Water Quality, as well as administrative penalties for construction, operations, effluent parameter discharges, and reporting violations. In addition, not all of the real property where wastewater utility system assets are located is owned by Webb Creek. Instead, certain Webb Creek system assets are located on land owned by other entities affiliated with Webb Creek through common ownership.

7. On August 3, 2016, pursuant to G.S. 62-116(b) and G.S. 62-118(b), the Public Staff filed a Petition in Docket No. W-864, Sub 11, requesting that the Commission issue an order as to the Webb Creek system: (1) declaring an emergency, (2) appointing Pluris as emergency operator (EO) of the Webb Creek system, and (3) approving an emergency rate increase for the Webb Creek wastewater utility system. On August 8, 2016, the Commission issued its Order Appointing Emergency Operator, Approving Increased Rates and Requiring Customer Notice in Docket No. W-864, Sub 11 (the EO Order).

8. Webb Creek's registered agent is Joseph Hal Kinlaw, Jr., and it is believed that Mr. Kinlaw is president of Webb Creek. Mr. Kinlaw has been a stockholder and officer of Webb Creek since he incorporated that entity in 1985. Mr. Kinlaw managed Webb Creek's operations for many years. Mr. Kinlaw is also involved in the related entities that developed the residential subdivisions served by the Webb Creek system.

9. Mr. Kinlaw is now incarcerated in federal prison at the Ashland Correctional Institute in Ashland, Kentucky, serving a 17-year sentence resulting from a conviction on charges of bank fraud. Mr. Kinlaw was sentenced and taken into custody by federal authorities on November 10, 2016, three months after issuance of the EO Order.

10. On June 7, 2017, the Public Staff filed its Complaint and Petition for Revocation of Franchise in Docket No. W-864, Sub 14 pursuant to G.S. 62-112 and Commission Rule R1-9, requesting that the Commission revoke the franchise, Certificates of Public Convenience and Necessity, and operating authority previously granted to Webb Creek.

11. G.S. 62-112 (b) provides, in pertinent part, as follows:

> Any franchise may be suspended or revoked, in whole or in part, in the discretion of the Commission, upon application of the holder thereof; or, after notice and hearing, may be suspended or revoked, in whole or in part, upon complaint, or upon the Commission's own initiative, for wilful failure to comply with any provision of this Chapter, or with any lawful order, rule, or regulation of the Commission promulgated thereunder, or with any term, condition or limitation of such franchise; provided, however, that any such franchise may be suspended by the Commission upon notice to the holder or lessee thereof without a hearing for any one or more of the following causes:
>
> (1) For failure to provide and keep in force at all times security, bond, insurance or self-insurance for the protection of the public as required in G.S. 62-268 of this Chapter.
>
> (2) For failure to file and keep on file with the Commission applicable tariffs or schedules of rates as required in this Chapter.
>
> (3) For failure to pay any gross receipts, use or privilege taxes due the State of North Carolina within 30 days after demand in writing from the agency of the State authorized by law to collect the same; provided, that this subdivision shall not apply to instances in which there is a bona fide controversy as to tax liability.
>
> (4) For failure for a period of 60 days after execution to pay any final judgment rendered by a court of competent jurisdiction against any holder or lessee of a franchise for any debt or claim specified in G.S. 62-111(b) and (c).

12. In addition to the practical, operational, and financial problems and issues resulting from the deteriorated state of the Webb Creek system and the fact that Mr. Kinlaw is serving a

lengthy sentence in federal prison, there are various legal grounds adequate for the Commission to revoke Webb Creek's franchise.

13. One such ground is that Branch Banking and Trust Company (BB&T) made loans to Webb Creek which loans were secured with utility assets owned and used by Webb Creek. Webb Creek did not obtain Commission approval for those loans as required by G.S. 62-160 and Rule R1-16 when it pledged its utility assets to secure its debts to BB&T. Compliance with those requirements is an obligation of a public utility, such as Webb Creek. This was a "wilful failure to comply with" G.S. 62-160 and Commission Rule R1-16 which are, respectively, a provision of Chapter 62 and a lawful rule or regulation of the Commission, and thus is a ground for revocation of the CPCN.

14. Webb Creek subsequently defaulted on the loans from BB&T. BB&T sued Webb Creek and Mr. and Mrs. Kinlaw in Robeson County Superior Court, and obtained a judgment against them. That judgment was transcribed in Onslow County Superior Court on April 8, 2014, in the amount of $1,624,180 in principal, plus $24,213 in interest, plus late fees of $6,528, plus interest at the legal rate on $1,624,180 from April 4, 2013, until the judgments are satisfied, plus $248,238 in attorney's fees in Onslow County File No. 14-T-43 (BB&T Judgment). The BB&T Judgment against Webb Creek poses a threat to the Webb Creek system, as it remains unsatisfied and continues to accrue interest. The failure to pay the BB&T Judgment is grounds for revocation of Webb Creek's franchise under G.S. 62-112(b)(4).

15. As detailed below, in addition to the BB&T Judgment there are significant federal, state, and local liens against Webb Creek, which are a product of failure to pay various taxes which may include a "failure to pay gross receipts, use, or privilege taxes," which would be another ground for revocation of Webb Creek's franchise. The liens of Onslow County, the United States Treasury, the North Carolina Department of Revenue, and the North Carolina Department of Commerce - Employment Security Commission against Webb Creek and the other affiliated entities which own lift station sites, pose further threats to the future of the Webb Creek system.

16. The ownership of lift station sites where Webb Creek utility system assets are located is spread among several entities other than Webb Creek, which entities are affiliated with Webb Creek by some common ownership, as follows:

System Component	Location	Owner
WWTP	250 Zachary Lane	Webb Creek
4 vacant lots (adjacent to WWTP)	252, 254, 256, and 258 Zachary Lane	Hal Kinlaw, Jr. (252) Group Eight, Ltd. (254) Hal Kinlaw, Jr. (256) Kinlaw Investment Co. (258)
Lift station no. 1	Beside 200 Glenwood Drive	Webb Creek
Lift station no. 2	Beside 149 Parnell Road	Group Eight, Ltd. (This entity owns or owned and operates or operated a convenience store.)
Lift station no. 3	Beside 102 Charlton Road	Group Eight, Ltd.

Lift station no. 4	Sandy Ridge Elementary School	Onslow County Board of Education
Lift station no. 5	Beside 227 Gray Fox Run	Group Eight, Ltd.
Lift station no. 6	Beside 136 Byrum Road	Parnell-Kinlaw Group, Inc.
Lift station no. 7	At intersection of Jessie Circle and Kelly Circle	Webb Creek
Lift station no. 8	Beside 116 Gamble Way	Hurst-Law Group, Inc.

17. Except for the Onslow County Board of Education, which owns the Sandy Ridge Elementary School, the entities other than Webb Creek owing land where Webb Creek utility assets are located are developer entities which Mr. Kinlaw is or was affiliated in some form or fashion. As of October 2015, there were recorded liens in Onslow County against Mr. Kinlaw and these various entities as follows:

<u>Group Eight Ltd.</u>

Lift Station no. 2 – Beside 149 Parnell Road
Lot – 254 Zachary Lane
Lift Station no. 3 – Beside 102 Charlton Road
Lift Station no. 5 – Beside 227 Gray Fox Run
Onslow County Property Taxes – $1,871
North Carolina Department of Commerce – Liens – $85,402
North Carolina Department of Revenue – Liens – $69,344
U.S. Treasury (IRS) – Judgments – $123,817

BB&T – Judgments – Principal	$6,048,325
– Plus Interest	$111,122
– Plus Late Fees	$123,874
– Plus Attorneys' Fees	$940,060

<u>Parnell Kinlaw Group, Inc.</u>

Lift Station no. 6 – Beside 136 Byrum Road

Onslow County Property Taxes –	$17,468
BB&T – Judgments – Principal	$6,478,035
– Plus Interest	$111,122
– Plus Late Fees	$23,768
– Plus Attorneys' Fees	$991,939

<u>Hal Kinlaw Jr.</u>

Lot – 252 Zachary Lane
Lot – 256 Zachary Lane
Onslow County Property Taxes – $14,201
First Citizens – 5 Lis Pendens – Amounts Unknown

BB&T – Six Judgments – Total Principal	$17,186,799
– Total Accumulated Interest	$256,560
– Total Late Fees	$162,933
– Total Attorneys' Fees	<u>$2,832,159</u>
Hal Kinlaw Jr. – Total	$20,438,451, plus accruing interest

Kinlaw Investment Company

Lot – 258 Zachary Lane
Onslow County Property Taxes – $2,501

BB&T – Judgment – Principal	$604,399
– Plus Interest	$5,975
– Plus Late Fees	$2,167
– Plus Attorneys' Fees	$91,881

Webb Creek Water and Sewage, Inc.

WWTP – 250 Zachary Lane
Lift Station no. 1 – Beside 200 Glenwood Drive
Lift Station no. 7 – Intersection Jessie Circle and Kelly Circle
Onslow County Property Taxes – $94,160

BB&T – Judgment – Principal	$1,624,180
– Plus Interest	$24,213
– Plus Late Fees	$6,528
– Plus Attorneys' Fees	$248,238
Total BB&T	$1,903,159, plus interest at the legal rate from April 4, 2013, until the judgment is paid

U.S. Treasury (IRS) – Judgment – $73,790
North Carolina Department of Revenue – Liens – $4,758
North Carolina Department of Commerce – Liens – $910
Webb Creek – Total $2,076,777, plus accruing interest

18. The recorded liens against Webb Creek and its assets are far in excess of the original cost net investment in the wastewater utility system assets based upon the Public Staff's determination that Webb Creek's rate base did not exceed zero.

19. Onslow County has filed several lawsuits against Webb Creek and other entities affiliated with it, including affiliates that own some of the lift station sites where Webb Creek utility assets are located, to collect unpaid real and personal property taxes owed Onslow County by these various entities. Onslow County seeks appointment of a commissioner to sell these properties in order to satisfy delinquent personal and real estate taxes owed Onslow County.

20. There may be other civil litigation pending against some of these affiliated entities which own lift station sites that may further complicate the situation with regard to sites where Webb Creek utility assets are located.

21. Another ground for revocation is that Webb Creek has been materially non-compliant with G.S. 143-215.1, the NPDES Permit and Collection Permit, and Webb Creek has been issued many Notices of Violation and administrative penalties from DEQ's Division of Water Quality for construction, operations, effluent parameter discharges, and reporting violations. This non-compliance and these violations materially violate Commission Rule R10-7, which requires compliance with DEQ permits, rules and regulations. Such violations were largely uncorrected by Webb Creek as evidenced by the necessity of Pluris, after being appointed EO in August 2016, to invest over $500,000 as of November 2017, in its efforts to address and remedy

to the extent possible issues and problems in the Webb Creek wastewater system, to recover treatment capacity that had been lost, to attempt to address compliance issues, to stabilize operations, and in an unsuccessful attempt to make arrangements with BB&T to acquire system assets.[1]

22. Webb Creek has failed to comply with provisions of Chapter 62 and Commission rules and regulations. While the full extent of such non-compliance is not known, the known facts and circumstances establish that Webb Creek's unauthorized pledging of utility assets to secure its loans from BB&T violated at least one provision of Chapter 62 (G.S. 62-160), and at least one Commission rule (Rule R1-16), which non-compliance has created obvious and significant risks for Webb Creek's ratepayers.

23. There is no reasonably foreseeable or feasible scenario in which Webb Creek would be able to resume operation of this system. The only clear path to bringing long term stability to the provision of public utility wastewater service in the Webb Creek service area involves replacing Webb Creek with a competent and well-capitalized public utility that can make the investments necessary to bring the Webb Creek system into compliance and stabilize the provision of service to the public in this service area.

Pluris' Application for a CPCN

24. Pluris Webb Creek, LLC is a public utility and a wholly-owned subsidiary of Pluris Holdings, LLC. Other wholly-owned subsidiaries of Pluris Holdings, LLC include: (1) Pluris, LLC, which is a public utility operating a wastewater utility system serving North Topsail and nearby mainland areas near Sneads Ferry in Onslow County, and (2) Pluris Hampstead, LLC, which is a public utility operating a regional wastewater system near Hampstead in Pender County.

25. Pursuant to the EO Order, Pluris has served as EO for Webb Creek since August 2016. Since its appointment as EO, Pluris has invested over $500,000 in addressing problems, issues, and critical needs in the Webb Creek system. While there is a continuing compliance issue with regard to certain effluent limit exceedances, Pluris has otherwise brought the Webb Creek system into substantial compliance with applicable environmental and operational requirements.

26. Pluris plans to acquire the assets comprising the Webb Creek system through the ongoing tax foreclosure process, or by other means. Pluris has advised the Public Staff that if Pluris is able to acquire the Webb Creek franchise and system, it will replace the 30+ year old existing SBR treatment plant with a new membrane bioreactor (MBR) wastewater treatment plant. This is what other Pluris affiliates (Pluris, LLC, and Pluris Hampstead, LLC) have done in their Commission-assigned service areas. DEQ supports this outcome, as installation of an MBR plant at Webb Creek would be a significant upgrade, including materially improved effluent quality, which is desirable both from an environmental perspective, and for bringing this system into full compliance with DEQ requirements.

[1] Per Direct Testimony of Maurice Gallarda filed on November 22, 2017, in Docket No. W-1314, Sub 1, at Page 14, Line 15.

27. While Pluris has made significant improvements to the Webb Creek wastewater system, Pluris has concluded that despite its investments in that system, full compliance with DEQ requirements cannot be achieved with the existing Webb Creek SBR WWTP. As a result, Pluris has entered into a Letter of Intent to acquire a tract of land in the immediate vicinity of the existing Webb Creek WWTP. This tract can be the site for a new MBR wastewater treatment plant to be built by Pluris, which will be adequately sized to serve the Webb Creek and The Pines Development service areas (new MBR tract).

28. Building an MBR plant from scratch would be less expensive and simpler by virtue of starting with the new MBR tract and a clean slate, rather than continuing efforts to achieve compliance with the existing aged SBR WWTP. This approach would allow Pluris to avoid or minimize issues related to acquiring the existing Webb Creek plant and plant site, the cost of such an acquisition, and the cost of later decommissioning it, and thereby avoiding potential legal issues with the existing plant.

29. Pluris is well capitalized and is prepared to make the necessary capital investment to stabilize the provision of service in the Webb Creek service area on a going forward basis provided it is able to do so under its own CPCN and not merely as EO for the Webb Creek system. If Pluris can secure the Webb Creek system assets necessary for it to provide service in the Webb Creek service area, it will be in the public interest for Pluris to be granted a CPCN and for the situation in the Webb Creek service area to be stabilized on a long-term, going-forward basis.

30. Granting a CPCN to Pluris to serve the Webb Creek service area is in the public interest, provided that Pluris can achieve sufficient progress on a path to securing the utility assets necessary to provide wastewater utility service in that service area. In order to facilitate a seamless transition in service providers and for the benefit of Webb Creek's ratepayers, it is in the public interest, that any revocation of Webb Creek's CPCN and the granting of a CPCN to Pluris should be done simultaneously.

31. It is in the public interest to grant a CPCN to Pluris authorizing Pluris to provide wastewater utility service in the service area formerly served by Webb Creek and to simultaneously revoke Webb Creek's CPCN, upon Pluris filing with the Commission a verified statement confirming that (1) Pluris has acquired the new MBR tract; (2) Pluris has purchased the lift station sites that are necessary to provide wastewater utility service through the Onslow County tax foreclosure sale process, or acquired them by other means; and (3) Pluris has acquired sufficient portions of the Webb Creek system assets to provide wastewater utility service. Such verified statement should include letters from a North Carolina licensed attorney and a North Carolina licensed professional engineer certifying that Items 2-3, respectively, have been accomplished.

32. Communications from the Webb Creek customers received by the Public Staff have been almost entirely supportive of Pluris' EO operation of the wastewater system.

33. Pluris should be required to post a total bond in the amount of $200,000 for the Webb Creek franchise. Such total bond requirement would include the $10,000 already posted in Docket No. W-1314, Sub 0, and an additional $190,000 to be posted prior to the issuance of a CPCN to Pluris.

34. The letter of credit proceeds of $100,000 obtained by the Commission through forfeiture of Webb Creek's bond security should be retained by the Commission until the Webb Creek WWTP is decommissioned. This outstanding liability poses a potential health and environmental risk to the surrounding community of Webb Creek ratepayers. If the cost to decommission that site are less than $100,000, plus accrued interest, the remaining balance should be considered cost free capital paid to Pluris, which would result in a reduction in rate base.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-4

The evidence supporting these findings of fact is contained in the pleadings and the entirety of the record. These findings are primarily jurisdictional and procedural matters, as well as foundational undisputed matters of fact established in the pleadings or otherwise. In fact, Webb Creek has made no filings in connection with these dockets and no representative of Webb Creek appeared at these hearings.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-6

The evidence supporting these findings of fact is contained in the testimony of Public Staff witnesses Junis and Gregson, the testimony of Pluris witness Gallarda, and the Commission's EO Order.

The various problems and issues with the operations, assets, equipment, and management of the Webb Creek system are established in the testimony of Public Staff witnesses Junis and Gregson. The testimony of Pluris witness Gallarda also addresses some aspects of the problems with the Webb Creek system, particularly including the problems and challenges Pluris has faced as the EO of the Webb Creek system in terms of attempting to bring that system into compliance with DEQ requirements. As detailed in the Commission's EO Order issued pursuant to the Public Staff's Petition for Appointment of an Emergency Operator, DEQ's Division of Water Quality has issued over 500 Notices of Violation and administrative penalties to Webb Creek for construction, operations, effluent parameter discharge violations, and reporting violations.

In addition, as reflected in the testimony of witness Junis in this docket and the Commission's EO Order, there are relatively unique problems and issues with the assets, equipment, and properties comprising the Webb Creek system as a product of the fact that not all of the real property where Webb Creek system assets are located is owned by Webb Creek. Public Staff witness Junis filed testimony supporting the Public Staff's Complaint and Petition for Revocation on three separate occasions. As shown therein, five of the eight Webb Creek lift station sites are owned by entities other than Webb Creek, which entities are affiliated with Webb Creek by some common ownership and/or management. The problematic issues with ownership of the lift station sites are vividly illustrated by Junis Exhibit 2, which is a copy of the Complaint filed by Onslow County against one of the Kinlaw-affiliated entities, Group Eight, Ltd., to collect delinquent property taxes and seeking the tax foreclosure sale of the three Webb Creek wastewater system lift station sites owned by Group Eight, Ltd.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 7

This finding of fact relates to a procedural matter and is a foundational and a matter of fact established in the pleadings.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8-9

The evidence for these findings of fact is contained in the testimony of Public Staff witness Junis.

The findings of fact regarding J. Hal Kinlaw, Jr., as Registered Agent for and believed to be president of Webb Creek, are supported by the testimony of Public Staff witness Junis. Witness Junis testified that Mr. Kinlaw managed Webb Creek operations for many years, but since November 10, 2016, he has been in the custody of federal authorities. Witness Junis stated that Mr. Kinlaw is presently an inmate incarcerated in the Ashland Correctional Institute in Ashland, Kentucky, serving a 17-year sentence resulting from a conviction on federal charges of bank fraud.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10-11

Finding of Fact No. 10 is procedural and foundational and is a matter of fact established in the pleadings. Finding of Fact No. 11 is a recitation of a provision of Chapter 62 and is not subject to contest by any party.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-14

These findings of fact are based on the matters alleged in the Public Staff's Complaint and Petition, and are supported by the testimony of Public Staff witness Junis. BB&T made loans to Webb Creek, which loans were secured by utility assets owned by Webb Creek. Webb Creek did not obtain Commission approval to pledge utility assets, as required by G.S. 62-160 and Commission Rule R1-16 when it pledged its utility assets to secure its debts to BB&T. Webb Creek defaulted on its loans to BB&T, as detailed in the Junis testimony and, as shown by Junis Exhibit 1, which is the BB&T Judgment, BB&T has a judgment against Webb Creek, as well as Mr. and Mrs. Kinlaw, in the principal amount of $1,624,180, plus interest, late fees, and attorney's fees. The BB&T Judgment is a lien against the Webb Creek assets and thus those assets are at risk because the BB&T Judgment remains unsatisfied. The Public Staff has concluded that Webb Creek is unable to provide an adequate wastewater treatment system as Mr. Kinlaw is unavailable to perform management functions for a 17-year period, Webb Creek does not have accessible management, and it does not have access to funds to upgrade and replace aged utility plant as necessary. Webb Creek is thus totally unable to provide adequate service for the public convenience and necessity of the Webb Creek customers. While it appears doubtful that the Webb Creek corporate entity is a going concern, its failure to pay the BB&T Judgment is grounds for revocation of Webb Creek's franchise and CPCN under G.S. 62-112(b)(4).

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15-20

The evidence supporting these findings of fact is contained in the testimony of Public Staff witness Junis, and the exhibits thereto, as well as the testimony of Pluris witness Gallarda. Junis Exhibit 2 is a copy of the Complaint filed by Onslow County against Group Eight, Ltd., a Kinlaw / Webb Creek affiliate which owns all or part of three lift station sites. Onslow County seeks to sell those sites at public auction in order to generate revenue to pay the taxes owed to Onslow County by Group Eight, Ltd. The existing reported liens against Webb Creek assets are far in excess of the value of those assets. Thus, judgment and lien creditors have the ability to force the public auction of these lift station sites, which presents significant threats to the stability of the provision of wastewater treatment service to customers in the Webb Creek service area. Webb Creek does not own or control the sites where material components of the wastewater utility system are located, as five duplex lift stations, four of which have substantial recorded liens against them totaling a combined $15.126 million, are owned by entities other than Webb Creek.

As reflected in the testimony of witness Junis, some time ago First Citizens Bank filed a number of Notices of Lis Pendens as to Mr. Kinlaw, which indicate that there is or was some litigation with him that could impact the title to real property owned in his name. The extent of any such litigation is not documented in the record, but those Lis Pendens further reflect the unsettled circumstances of Webb Creek's owner.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 21

The evidence supporting this finding of fact is contained in the testimony and exhibits of Public Staff witness Junis, the testimony of Public Staff witness Gregson, the testimony of Pluris witness Gallarda, and the Public Staff's Report filed on September 8, 2017. The record in general, and the testimony of witness Junis in particular, establishes that for some years there have been various escalating problems and issues with the operations, facilities, and management of the Webb Creek system. Due to material non-compliance with G.S. 143-215.1, the NPDES Permit, and the Collection Permit, as of August 2016, the Public Staff reported that Webb Creek had incurred over 500 Notices of Violation from DEQ's Division of Water Quality, as well as administrative penalties, for construction, operations, effluent parameter discharge exceedances, and reporting violations. Since then, the Webb Creek NPDES permit has expired.

In particular with respect to the Notices of Violation, the Public Staff reported that prior to the appointment by the Commission of Pluris as EO in August 2016, the Webb Creek facility had 39 enforcement actions initiated by the Division of Water Resources for effluent limit violation of its NPDES permit. Further, the Public Staff noted that the violation totals prior to August 2016 included: 112 biological oxygen demand (BOD) violations, seven chlorine violations, 34 fecal coliform violations, 82 enterococcus violations, two flow violations, 23 total nitrogen violations, four pH violations, one dissolved oxygen violation, and 246 frequency violations. The Public Staff observed that since August 2017 the Webb Creek wastewater system has had five BOD violations, 34 enterococcus violations, one flow violation, and four total nitrogen violations.

Public Staff witness Gregson is now Interim Deputy Director of DEQ's Division of Water Quality. His testimony establishes that when he was Regional Supervisor of DEQ's Wilmington office he began to see an increase in Webb Creek's effluent limit violations in 2014. He testified that when DEQ inspected the Webb Creek WWTP and spoke with Webb Creek's plant operator regarding the situation, the operator "actually raised concerns also with his ability to operate the plant at that time and going from 2014 probably to around mid-2015, due to the lack of commitment on the owner of the facility to spend money on the - on the plant and collection system." (January 8, 2018 Transcript p. 23). Webb Creek's effluent limit violations prompted a compliance inspection by DEQ Wilmington staff in 2015, and during that inspection they found numerous problems with pump stations, missing pumps, and poor maintenance of the facility. That inspection revealed that five of the duplex lift stations were operating with only one pump, rather than the two pumps required by DEQ regulations, and that the operator could not get the pumps repaired because Webb Creek could not pay for the pumps to be repaired. Such violations were largely uncorrected by Webb Creek as evidenced by the necessity of Pluris, after being appointed EO in August 2016, to invest over $500,000 as of November 2017, in its efforts to, among other things, address and remedy to the extent possible operational and maintenance issues and problems in the Webb Creek wastewater system.

Witness Gregson commented that one of the most pressing issues with the Webb Creek wastewater system when Pluris took over as EO was to remove and haul away the built-up sludge and to replace or add additional pumps to the pump stations that were missing pumps. He stated that Pluris also promptly fixed the inlet control valve on the third sequencing batch reactor and brought it back into service which greatly improved the operation of the plant. Witness Gregson maintained that although the plant continues to have problems consistently meeting enterococcus limits under the operation of the EO, the problem lies with the design of the facility rather than Pluris' operation of the facility.

The Public Staff contended that the extent to which Webb Creek failed to comply with DEQ requirements, the number of violations issued to it by DEQ, and Webb Creek's failure to adequately and timely address such matters, materially violate Commission Rule R10-7, which requires compliance with DEQ permits, rules, and regulations.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 22-23

These findings of fact are conclusory in nature, premised on the foregoing factual matters, none of which are disputed or contested by any party. It is apparent that Webb Creek has failed to comply with various applicable provisions of Chapter 62 and/or Commission rules. While the full extent of such non-compliance is not known, the proven facts and circumstances establish that Webb Creek has materially violated at least one provision of Chapter 62 (G.S. 62-160) and several Commission Rules, including Rule R1-16 by failing to obtain authority from the Commission to pledge its utility assets to secure its loans from BB&T. That non-compliance and the BB&T Judgment has created obvious and significant risks for ratepayers in the Webb Creek service area. Webb Creek also violated Rule R10-7 by its ongoing and material failures to comply with DEQ requirements. Based on the circumstances presented, there is no reasonable, foreseeable, or feasible scenario in which Webb Creek could resume operation of its system and the only clear path to bringing long-term stability to the provision of public utility wastewater service in the Webb Creek service area requires that Webb Creek be replaced with a competent and wellcapitalized public utility that can stabilize provision of service in the Webb Creek service area.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 24-29

The evidence for these findings of fact is contained in the entirety of the record, in the testimony of Pluris witness Gallarda, in the Commission's EO Order, and in the pleadings.

The entirety of the record establishes that Pluris Webb Creek, LLC is a public utility and a wholly-owned subsidiary of Pluris Holdings, LLC. The testimony of Pluris witness Gallarda and the Commission's records establish that other wholly-owned subsidiaries of Pluris Holdings, LLC operate public utility wastewater systems in other areas in North Carolina.

The pleadings and the EO Order issued in Docket No. W-864, Sub 11 reflect the Commission's appointment of Pluris as EO of the Webb Creek system in August, 2016. The testimony of Pluris witness Gallarda details Pluris' efforts to bring the Webb Creek system into compliance with DEQ requirements. Witness Gallarda testified that Pluris has invested over $500,000 in addressing problems, issues, and critical needs in the Webb Creek system, and, by doing so, it has achieved substantial compliance with DEQ requirements. Pluris is not able, however, to achieve full compliance with those requirements because of certain problems or conditions with the existing Webb Creek WWTP that simply cannot be corrected to the point that total compliance can be achieved using the existing system assets.

The Public Staff advised the Commission in its Petition for Appointment of Emergency Operator that Pluris is interested in acquiring the Webb Creek service area. As established by witness Gallarda's testimony in the present dockets, Pluris has been working to acquire the assets comprising the Webb Creek system. Its efforts to obtain those assets through BB&T, which as a significant judgment creditor of Webb Creek by virtue of the BB&T Judgment, proved unsuccessful. Pluris now plans to acquire the assets that it needs through Onslow County's ongoing tax foreclosure cases or by other means.

Witness Gallarda's testimony establishes that Pluris believes the prudent course with regard to the future provision of service in the Webb Creek service area is to abandon the existing Webb Creek WWTP and to build a new MBR wastewater treatment plant on the new MBR tract, near the site of the existing WWTP. Public Staff's support for such an outcome is documented in the testimony of witness Junis, as well as the testimony of witness Gregson, Interim Deputy Director of DEQ's Division of Water Quality, who testified in response to a question from Public Staff counsel that MBR plants operated by other Pluris affiliates "basically produce drinking water quality effluent." (January 8, 2018 Transcript p. 34). Both the Public Staff and DEQ support this plan, as installation of an MBR plant to serve the Webb Creek service area would be a significant upgrade and is desirable from both an environmental prospective and because it would enable the system to be brought into full compliance with DEQ requirements.

In pursuit of that approach, Pluris has entered into a Letter of Intent to acquire the new MBR tract, which is the immediate vicinity of the Webb Creek WWTP. Pluris is otherwise prepared to take actions as necessary to secure Webb Creek system assets, provided that it has sufficient assurance that it will be granted a CPCN authorizing it to serve the Webb Creek service area. Pluris is able and willing to provide the management, expertise, and capital necessary to stabilize the provision of service in the Webb Creek service area on a going forward basis.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 30-31

The evidence for these findings of fact is contained the testimony of Public Staff witnesses Junis and Gregson, in the testimony of Pluris witness Gallarda, and in the entire record for these proceedings.

The evidence presented in these dockets clearly indicates that Webb Creek has failed to comply with provisions of North Carolina Public Utilities Laws and Regulations Chapter 62 and the Commission's Rules and Regulations and that there is no reasonably foreseeable or feasible scenario in which Webb Creek would be able to resume operation of this system. By every indication Webb Creek is a "troubled utility." In that situation, "[i]t is, and shall continue to be the policy of this Commission to take such actions as will encourage the larger water and sewer utilities with greater operational and capital resources[] to acquire smaller, under-capitalized, less efficient systems. Such policy serves the public interest by promoting efficiencies through economies of scale and generally results in more favorable rates and an enhanced quality of service." Docket No. W-354, Sub 133, Order Determining Regulatory Treatment of Gain on Sale of Facilities (September 7, 1994).

Pluris is a large, well-capitalized sewer utility. Pluris has the technical, managerial, and financial capacity to own and operate the wastewater treatment system serving the Webb Creek service area and, given that it is currently the EO of the Webb Creek system, this would be a seamless transition if Pluris had been able to purchase Webb Creek's assets from Webb Creek and/or BB&T, i.e., Webb Creek's principal lienholder. Unfortunately, Pluris' efforts to purchase the assets that it needs from Webb Creek and/or BB&T through traditional means have been unsuccessful.

During the hearing, after acknowledging that its efforts to acquire those portions of Webb Creek's assets that it needed through the traditional method, i.e., a negotiated sale and purchase agreement had been unsuccessful, Pluris indicated that its lack of success did not diminish its desire to be the certificated provider of wastewater utility service in the Webb Creek service area. Pluris thereafter detailed a plan by which it could acquire the assets that it needed to provide such service through the use of a less traditional acquisition method. Pluris' plan has three main prongs. First, Pluris would purchase a specified parcel of land, located near the franchised service territory, considered suitable to construct a new MBR plant. Upon completion, the newly constructed plant would be used to provide wastewater utility service to the customers in Webb Creek's franchised service territory. Second, Pluris would attempt to purchase certain assets that are currently owned by Webb Creek and/or other affiliated companies in which Mr. Kinlaw has an interest which are being foreclosed upon by Onslow County for failure to pay the required property taxes. Third, Pluris would acquire sufficient portions of the Webb Creek system assets to provide service and would also post a bond in the amount of $190,000. After completion of these essential objectives, Pluris would file with the Commission a verified statement affirming that such objectives had been completed and would then expect that the Commission would award Pluris the CPCN for the Webb Creek service area at some unspecified date in the future without any further proceedings. However, Pluris testified that before it will pursue any of the aforementioned objectives of this plan, Pluris requests sufficient assurance from the Commission that it will be granted a CPCN authorizing it to serve the Webb Creek service area.

The Commission has carefully examined Pluris' non-traditional acquisition plan and its request for assurances from the Commission that are the foundation of such plan. Based on the evidence herein presented and the entire record, it is clear that Webb Creek's current troubled utility status is untenable on an ongoing basis and that Webb Creek's ratepayers/customers deserve some assurance that they will receive adequate and reliable wastewater treatment service from a financially sound and technically competent provider. From the evidence, it is also clear that traditional solutions that the Commission has employed in the past to resolve a troubled utility's problems are not an option in this case because multiple entities have potential interests in assets used by Webb Creek to provide utility service and because of the various other specific reasons discussed herein. Thus, in order to ensure that the customers in the Webb Creek service area will continue to receive adequate and reliable wastewater utility service and that their ability to receive such service shall not be impaired by those entities, the Commission must consider non-traditional, creative solutions such as the one proposed by Pluris in these proceedings. In doing so, however, the Commission is mindful of the fact that the needs of the rate-paying public must be considered and protected to the greatest extent possible.

A strength of the plan proposed by Pluris is that it potentially puts Pluris, a well-managed and well-capitalized utility provider in position to become the utility provider in Webb Creek's present service area. In its capacity as the EO, Pluris has made substantial capital expenditures to improve the quality of service received by Webb Creek's customers and has substantially addressed the concerns expressed by DEQ concerning the condition and operation of the SBR plant. Additionally, Pluris has put forth plans to demolish Webb Creek's SBR plant which is nearing the end of its useful life and to replace it with a new MBR plant which will be appropriately sized to provide service to Webb Creek and other customers in nearby areas. Both the Public Staff and DEQ are in favor of the demolition of the SBR plant and the replacement with the MBR plant. However, Pluris' proposed plan has certain limitations, including: (1) there is no assurance that Pluris will succeed with its tax foreclosure acquisition strategy and (2) there is no set timetable by which Pluris will acquire the necessary assets to become the certificated service provider.

After carefully considering the strengths and the weaknesses of the proposed plan, the Commission finds and so concludes that there is merit to Pluris' proposal. Further, the Commission is of the opinion and therefore finds and concludes that Pluris' request that it be given assurances from the Commission that it will be granted a CPCN before it embarks on such a proposal is reasonable in light of the circumstances herein described. In reaching this conclusion, the Commission takes notice of the ownership and operational issues set out by the Public Staff, DEQ, and Pluris in their respective testimony in these proceedings and concludes that the issuance of a CPCN to Pluris once the aforementioned requirements are met should resolve these issues; should bring stable and reliable service to the Webb Creek service area; and is in the overall best interests of the Webb Creek customers.

The Commission, therefore, grants Pluris assurance that: (1) Webb Creek's CPCN will be revoked on an unspecified date in the future without the need for a further hearing on this issue and (2) Pluris would simultaneously be awarded the CPCN to serve the Webb Creek franchised territory; provided, however, that the preceding shall only occur if Pluris does the following:

(1) Within six months of the date of this Order, Pluris shall file a verified statement with the Commission confirming that

(a) Pluris has acquired the new MBR tract;
(b) Pluris has purchased all lift station sites that are necessary to provide wastewater utility service through the Onslow County tax foreclosure process, acquired them by other means, or has obtained lawful control of such assets; and
(c) Pluris has acquired sufficient portions of the Webb Creek system assets to provide adequate and reliable service to the Webb Creek customers;

(2) Pluris shall include with its verified statement:

(a) A letter from a North Carolina licensed attorney certifying that Pluris has purchased, acquired ownership, or otherwise has obtained lawful control of all lift station sites that are necessary to provide wastewater utility service to the residents and/or customers located in Webb Creek's franchised service territory;
(b) A letter from a North Carolina licensed professional engineer certifying that Pluris has acquired sufficient portions of the Webb Creek system assets to provide adequate and reliable wastewater utility service to the residents and/or customers located in Webb Creek's franchised service territory;

(3) If Pluris is unable to file such verified statement within six months of the date of this Order, Pluris may petition the Commission for a three-month extension of this requirement and the extension request shall be granted. Additional request for extensions by Pluris may be granted in the discretion of the Commission.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 32

The evidence to support this finding of fact is found in the Report of the Public Staff filed on September 8, 2017, and in the entirety of the record.

In its report filed on September 8, 2017, in Docket No. W-864, Sub 11, the Public Staff stated that it had received some correspondence regarding Pluris from residents living in the Webb Creek service area, and that such correspondence has been almost entirely supportive of Pluris.

Further, there have been no public witness testimony received at any of the evidentiary hearings held in these proceedings either objecting to Pluris' request for a CPCN for the Webb Creek service territory or citing any problems or concerns regarding Pluris' emergency operations of the Webb Creek wastewater system.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 33-34

The evidence to support these findings of fact is found in the testimony of Public Staff witness Junis filed on January 5, 2018. These recommendations are supported by Pluris and are otherwise uncontested.

IT IS THEREFORE, ORDERED as follows:

1. A certificate of public convenience and necessity to provide wastewater utility service in the franchised service area presently being served by Webb Creek shall be granted to Pluris once Pluris:

(1) Files a verified statement with Commission indicating that:

(a) Pluris has acquired the new MBR tract, which Pluris has previously described to the Commission;
(b) Pluris has purchased or acquired all lift station sites that are necessary to provide wastewater utility service to the residents and/or customers located in Webb Creek's franchised service territory through the Onslow County tax foreclosure process, acquired them by other means, or has obtained lawful control of such assets;
(c) Pluris has acquired sufficient portions, of the Webb Creek system assets to provide adequate and reliable wastewater utility service to the residents and/or customers located in Webb Creek's franchised service territory; and
(d) Pluris has posted an additional bond in the amount of $190,000; for a total bond amount of $200,000 for the Webb Creek franchise including the previously posted bond of $10,000 in Docket No. W-1314, Sub 0.

(2) Pluris shall include with its verified statement:

(a) A letter from a North Carolina licensed attorney certifying that Pluris has purchased, acquired ownership, or otherwise obtained lawful control of all lift station sites that are necessary to provide wastewater utility service to the residents and/or customers located in Webb Creek's franchised service territory; and
(b) A letter from a North Carolina licensed professional engineer certifying that Pluris has acquired sufficient portions, of the Webb Creek system assets to provide adequate and reliable wastewater utility service to the residents and/or customers located in Webb Creek's franchised service territory.

The aforementioned conditions shall be accomplished by Pluris within six months from the date of this Order unless Pluris petitions the Commission for a three-month extension of this requirement and such extension request shall be granted. Additional request for extensions by Pluris shall be granted in the discretion of the Commission. Once the aforementioned conditions have been satisfied in accordance with the provisions of this Order, it is the intention of the Commission that separate orders shall be contemporaneously issued by the Commission revoking the certificate of public convenience and necessity presently held by Webb Creek, and granting a certificate of public convenience and necessity to Pluris authorizing it to provide sewer service in the area previously served by Webb Creek Water and Sewage, Inc., without further proceedings.

2. The letter of credit proceeds of $100,000 obtained by the Commission through forfeiture of Webb Creek's bond security shall be retained by the Commission until the Webb Creek WWTP is decommissioned.

ISSUED BY ORDER OF THE COMMISSION
This the 28th day of June, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

DOCKET NO. W-864, SUB 14
DOCKET NO. W-1314, SUB 1

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. W-864, SUB 14 In the Matter of Complaint and Petition by Public Staff for Revocation of Franchise of Webb Creek Water and Sewage, Inc. DOCKET NO. W-1314, SUB 1 In the Matter of Application of Pluris Webb Creek, LLC, for a Certificate of Public Convenience and Necessity to Provide Sewer Utility Service in the Areas Presently Served by Webb Creek Water and Sewage, Inc., in Onslow County	)	ORDER GRANTING PLURIS WEBB CREEK, LLC'S MOTION TO MODIFY ORDER REQUIRING THE SATISFACTION OF CERTAIN CONDITIONS BEFORE THE ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

BY THE COMMISSION: On June 28, 2018, the Commission issued an Order Requiring Specific Conditions to be Satisfied Concerning the Granting of a Certificate of Public Convenience and Necessity to Pluris Webb Creek, LLC (Conditions Order). The Conditions Order required Pluris Webb Creek, LLC (Pluris) to meet certain conditions before the Commission would award Pluris a certificate of public convenience and necessity (CPCN) to provide wastewater utility service in the territory currently being served by Pluris as an emergency operator for Webb Creek Water and Sewage, Inc. (Webb Creek). In pertinent part, the Conditions Order stated:

> 1. A certificate of public convenience and necessity to provide wastewater utility service in the franchised service area presently being served by Webb Creek shall be granted to Pluris once Pluris:
>
> (1) Files a verified statement with Commission indicating that:

(a) Pluris has acquired the new MBR tract, which Pluris has previously described to the Commission;

(b) Pluris has purchased or acquired all lift station sites that are necessary to provide wastewater utility service to the residents and/or customers located in Webb Creek's franchised service territory through the Onslow County tax foreclosure process, acquired them by other means, or has obtained lawful control of such assets;

(c) Pluris has acquired sufficient portions, of the Webb Creek system assets to provide adequate and reliable wastewater utility service to the residents and/or customers located in Webb Creek's franchised service territory; and

(d) Pluris has posted an additional bond in the amount of $190,000; for a total bond amount of $200,000 for the Webb Creek franchise including the previously posted bond of $10,000 in Docket No. W-1314, Sub 0.

(2) Pluris shall include with its verified statement:

(a) A letter from a North Carolina licensed attorney certifying that Pluris has purchased, acquired ownership, or otherwise obtained lawful control of all lift station sites that are necessary to provide wastewater utility service to the residents and/or customers located in Webb Creek's franchised service territory; and

(b) A letter from a North Carolina licensed professional engineer certifying that Pluris has acquired sufficient portions, of the Webb Creek system assets to provide adequate and reliable wastewater utility service to the residents and/or customers located in Webb Creek's franchised service territory.

The aforementioned conditions were to be accomplished by Pluris within six months from the date of the Order unless Pluris petitions the Commission for a three-month extension of this requirement and such extension request shall be granted. Additional request for extensions by Pluris shall be granted in the discretion of the Commission.

On December 7, 2018, Pluris filed a motion Request[ing] Modification of the Conditions to be Satisfied Concerning the Granting of a CPCN to Pluris Webb Creek, LLC (Modification Motion). In the Modification Motion, Pluris stated that testing done subsequent to the date of issuance of the Conditions Order at the site that Pluris had optioned to build a new Membrane Bio Reactor (MBR) Waste Water Treatment Plant (WWTP) in order to provide adequate and reliable wastewater utility service to customers residing in the Webb Creek and Pines service territories indicated that the site was unsuitable for the construction of a WWTP, that this circumstance required Pluris to reconsider its decision not to purchase the WWTP owned by Webb Creek, that Pluris purchased Webb Creek's WWTP and three adjoining lots i.e., the new plant site, to provide adequate wastewater utility service to customers residing in the Webb Creek and Pines service territories during the year that it would take to construct the new MBR WWTP, that, as a result of its purchase of the Webb Creek WWTP, Pluris would now be responsible for the decommissioning costs of said plant, that the Commission had withheld the proceeds of Webb Creek's bond forfeiture in the Conditions Order in order to apply the proceeds to the decommissioning costs of said plant because the Commission anticipated that Webb Creek and not Pluris would continue to own the WWTP when the plant was decommissioned after the CPCN for the Webb Creek service territory had been transferred to Pluris, and that the Commission should release the proceeds of the Webb Creek's bond forfeiture to Pluris because Pluris and not Webb Creek is now the owner of the Webb Creek WWTP and Pluris and not Webb Creek would be responsible for such costs when the Webb Creek WWTP is decommissioned. Further, Pluris stated that the Public Staff had authorized Pluris to represent to the Commission that the Public Staff supports Pluris' requested modifications to the Conditions Order. Pluris thereafter requested that, because of the changed conditions detailed above, the Commission amend the Conditions Order to reflect that the Commission will disburse the proceeds, i.e., \$100,000, that the Commission received from the forfeiture of Webb Creek's bond security to Pluris upon the issuance of the CPCN to Pluris and to provide that Pluris' acquisition of the existing plant site , together with the certification by a North Carolina licensed professional engineer that the new plant site will suffice for construction of a new MBR plant which will be adequately sized to service Webb Creek and the Pines development services areas, together with satisfaction of the conditions in the Conditions Order, will suffice for revocation of Webb Creek's CPCN and issuance of a CPCN to Pluris.

On December 13, 2018, the Commission issued an Order Requesting Comments from the Public Staff Regarding Pluris' Motion to Modify the Conditions Order. (Order Requesting Comments). In the Order Requesting Comments, the Commission required the Public Staff to respond to the Modification Motion by December 18, 2018.

On December 18, 2018, the Public Staff filed Comments. In its comments, the Public Staff stated the Public Staff fully supported all the relief requested by Pluris in the Modification Motion. Further, the Public Staff stated that the construction of the new MBR WWTP on the site purchased by Pluris will save the \$175,000 purchase price for the other considered site, that the new site is much better suited for the MBR WWTP construction and that the construction of the MBR WWTP on the new plant site should reduce construction costs for the wastewater influent piping and treated effluent piping to the NPDES discharge location and provide area for future improvements as necessary.

After careful consideration, the Commission concludes that good cause exists to grant Pluris' Motion that the Conditions Order be modified as detailed above.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 21st day of December, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. W-390, SUB 13

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. W-390, SUB 13	)	
	)	
In the Matter of	)	
Request by Public Staff – North Carolina	)	ORDER DECREASING
Utilities Commission for Appointment of	)	EMERGENCY OPERATOR'S
Carolina Water Service, Inc. of North	)	PROVISIONAL RATES AND
Carolina as Emergency Operator of	)	REQUIRING CUSTOMER NOTICE
Riverbend Estates Water Systems, Inc.,	)	
in Macon County, North Carolina	)	

BY THE COMMISSION: On May 9, 2017, in Docket No. W-390, Sub 13, the Public Staff – North Carolina Utilities Commission (Public Staff) filed a Petition pursuant to G.S. 62-116(b) and G.S. 62-118(b) requesting that the Commission issue an order: (1) declaring an emergency, (2) appointing Carolina Water Service, Inc. of North Carolina (Carolina Water) as an emergency operator (EO) of Riverbend Estates Water Systems, Inc. (REWS), and (3) approving an emergency rate increase on a provisional basis for the water system serving Riverbend Estates Subdivision in Macon County, North Carolina (EO Petition). The Riverbend Estates water system has approximately 131 metered customers in single-family residential homes.

The Public Staff presented the EO Petition to the Commission at the May 15, 2017 Commission Staff Conference. The Public Staff recommended that the Commission issue an order finding that an emergency then existed due to the abandonment by REWS of the water system serving Riverbend Estates Subdivision, appointing Carolina Water the EO, ordering the EO to make installment payments to the Town of Franklin on the purchased water arrearage, and approving an emergency rate increase at the Public Staff's recommended provisional rates being a monthly base charge for zero usage of $35.00, and a usage charge of $11.95 per 1,000 gallons.

After carefully considering the May 15, 2017 Commission Staff Conference presentation, the Commission issued an Order dated May 16, 2017, concluding "that an emergency exists for the Riverbend Estates water system which is in imminent danger of losing adequate water utility service"; adopting the Public Staff's recommendations to appoint Carolina Water as the emergency operator for the Riverbend Estates water system effective on May 16, 2017; approving the Public Staff's recommended provisional rates; and requiring that a copy of the Order be served on all customers of REWS by Carolina Water no later than 15 days from the date of the Order. On June 1, 2017, Carolina Water filed its Certificate of Service indicating that customer notice was provided as required by the May 16, 2017 Order.

On March 13, 2018, Carolina Water filed a letter with the Commission requesting, among other things, that the Commission issue an order to reduce the provisional rates currently being charged by the EO to the Riverbend Estates Subdivision customers, effective for bills rendered on and after March 13, 2018. In particular, Carolina Water requested that the Commission approve Carolina Water's uniform statewide monthly base charge for zero consumption of $24.44

(for a meter size of less than one inch) and a commodity charge of $6.86 per 1,000 gallons, which is the exact usage amount per 1,000 gallons that the Town of Franklin charges to Carolina Water for the purchased bulk water. In support of its request, Carolina Water stated that the new proposed provisional rates are lower than the EO's current provisional rates authorized by the Commission[1] and approval of such rates would bring immediate rate relief to the Riverbend Estates Subdivision customers. Carolina Water has advised the Commission that the Public Staff agrees with Carolina Water's request to reduce the EO's provisional rates.

The reduced provisional rates proposed by Carolina Water will decrease the average monthly water bill from $85.19 to $53.25 based on an average usage of 4,200 gallons for bills rendered on and after March 13, 2018.

Based upon the foregoing, the Commission finds and concludes that the provisional rates currently being charged by the EO to the Riverbend Estates Subdivision customers should be reduced to Carolina Water's uniform statewide monthly base charge for zero consumption of $24.44 (for a meter size of less than one inch) and a usage charge of $6.86 per 1,000 gallons, which is the same usage charge per 1,000 gallons that the Town of Franklin charges to Carolina Water for the bulk purchased water. Further, the Commission finds and concludes that the reduced provisional rates to be charged by the EO should be effective for bills rendered on and after March 13, 2018, and customer notice should be provided.

Furthermore, the Commission is opinion and therefore finds and concludes that by a further order of the Commission, the Public Staff should be required to audit the revenues Carolina Water has received as EO from customers and all expenses and capital expenditures for the Riverbend water system for the EO period beginning May 16, 2017 through March 13, 2018, and should file with the Commission a report including recommendations as to the amount of revenues from the provisional rates that exceeded the EO's expenditures, and that the over-collection amounts, if any, should be refunded by Carolina Water to each customer.

IT IS, THEREFORE, ORDERED as follows:

1. That the revised Schedule of Provisional Rates, attached hereto as Appendix A, is approved for Carolina Water as the emergency operator of the Riverbend Estates water system, effective for bills rendered on and after March 13, 2018.

2. That a copy of this Order, including Appendix A, shall be mailed with sufficient postage or hand delivered by Carolina Water to all its affected customers in the Riverbend Estates Subdivision within three business days after the issuance date of this Order.

3. That Carolina Water shall submit to the Commission the attached Certificate of Service, properly signed and notarized, not later than 10 days after the issuance date of this Order.

4. That, by further order of the Commission, the Public Staff shall be required to audit the revenues Carolina Water has received as EO from customers and all expenses and capital

[1] See Commission Order issued on May 16, 2017, in Docket No. W-390, Sub 13.

expenditures for the Riverbend water system for the EO period beginning May 16, 2017 through March 13, 2018, and shall file with the Commission a report including recommendations as to the amount of revenues from the provisional rates that exceeded the EO's expenditures, and that the over-collection amounts, if any, should be refunded by Carolina Water to each customer.

ISSUED BY ORDER OF THE COMMISSION.
This is the 13th day of March, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

APPENDIX A

SCHEDULE OF PROVISIONAL RATES

for

RIVERBEND ESTATES WATER SYSTEMS, INC.
(Carolina Water Service, Inc. of North Carolina, Emergency Operator)

for providing water utility service in

RIVERBEND ESTATES SUBDIVISION

Macon County, North Carolina

WATER RATES AND CHARGES

Metered Rates: (Residential Service)

Monthly base charge, zero usage	$24.44
Usage charge, per 1,000 gallons	$ 6.86

Connection Charge:

$1,000 plus actual cost to connect to the Town of Franklin

Reconnection Charge:

If water service cut off by utility for good cause	$27.00
If water service discontinued at customer's request	$27.00

If water service is reconnected to the same customer at the same address within nine months of disconnection, then the reconnection charge shall be the base charge times the number of months disconnected.

WATER AND SEWER – EMERGENCY OPERATOR

<u>New Water Customer Charge:</u>	$27.00
<u>Bills Due:</u>	On billing date
<u>Bills Past Due:</u>	25 days after billing date
<u>Billing Frequency:</u>	Shall be monthly for service in arrears
<u>Finance Charges for Late Payment:</u>	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-390, Sub 13, on this the 13th day of March, 2018.

<u>CERTIFICATE OF SERVICE</u>

I, ______________________________, mailed with sufficient postage or hand delivered to all affected customers a copy of the Order issued by the North Carolina Utilities Commission in Docket No. W-390, Sub 13, and such Order was mailed or hand delivered by the date specified in the Order.

This the ____ day of ________________, 2018.

By: ______________________________
Signature

____
Name of Utility Company

The above named Applicant, ______________________________, personally appeared before me this day and, being first duly sworn, says that the required copy of the Commission Order was mailed or hand delivered to all affected customers, as required by the Commission Order dated ________________ in Docket No. W-390, Sub 13.

Witness my hand and notarial seal, this the ____ day of ______________, 2018.

____
Notary Public

____
Printed Name

(SEAL) My Commission Expires: ______________________________
Date

DOCKET NO. W-218, SUB 363A

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Aqua North Carolina, Inc., 202 MacKenan Court, Cary, North Carolina 27511, for Approval of Semiannual Adjustments to Water and Sewer System Improvement Charges pursuant to G.S. 62-133.12	))))))	ORDER APPROVING WATER AND SEWER SYSTEM IMPROVEMENT CHARGES ON A PROVISIONAL BASIS AND REQUIRING CUSTOMER NOTICE

BY THE COMMISSION: On May 1, 2018, Aqua North Carolina, Inc. (Aqua or Company), filed an application requesting authority to adjust its Water System Improvement Charges (WSIC) and Sewer System Improvement Charges (SSIC) effective July 1, 2018, pursuant to Commission Rules R7-39 and R10-26 (Application).

On June 11, 2018, the Public Staff filed a Notice of Public Staff's Plan to Present Comments and Recommendations at the Commission's June 25, 2018 Regular Staff Conference (Notice).

On June 25, 2018, the Public Staff presented this matter to the Commission at Staff Conference.

On the basis of the verified Application, the records of the Commission, and the comments and recommendations of the Public Staff, the Commission makes the following

FINDINGS OF FACT

1. Aqua is a corporation duly organized under the laws of and is authorized to do business in the State of North Carolina. Aqua is a franchised public utility providing water and/or sewer utility service to customers in North Carolina.

2. In Aqua's last general rate case, Docket No. W-218, Sub 363 (Sub 363 Rate Case), the Commission approved in its Order dated May 2, 2014, Aqua's request to utilize a WSIC and SSIC mechanism pursuant to G.S. 62-133.12, concluding that the rate adjustment mechanisms are in the public interest, and establishing WSIC and SSIC procedures for Aqua.

3. The implementation of the WSIC and SSIC for Aqua was first approved on December 22, 2014, effective January 1, 2015. The WSIC and SSIC procedures allow for semiannual adjustments to Aqua's rates every January 1st and July 1st for recovery of reasonable and prudently incurred investment in eligible system improvements completed and placed in service prior to the filing of the request.

4. Aqua's proposed adjustments to the WSIC and SSIC previously approved by the Commission on January 1, 2018, are as follows:

WATER AND SEWER – FILINGS DUE PER ORDER

	Previously Approved WSIC/SSIC Percentage	Net Change To WSIC/SSIC Percentage	Cumulative WSIC/SSIC Percentage
Uniform water	4.77%	-0.02%	4.75%
Uniform sewer	3.59%	0.40%	3.99%
Fairways/Beau Rivage water	4.27%	0.16%	4.43%
Fairways/Beau Rivage sewer	4.53%	0.00%	4.53%
Brookwood/LaGrange water	5.39%	-0.68%	4.71%

5. The WSIC/SSIC percentages above include the Experience Modification Factor (EMF) adjustments from the 2017 annual WSIC/SSIC revenue review. The impact to the rate divisions are Aqua Uniform Water – adjusted downward by -0.02% (due to overcollection in 2017), Aqua Uniform Sewer – adjusted downward by -0.06% (due to overcollection in 2017), Fairways/Beau Rivage Water – adjusted downwards by -0.08% (due to overcollection in 2017), Fairways/Beau Rivage Sewer – adjusted upwards by 0.02% (due to undercollection in 2017) and Brookwood Water – adjusted upward by 0.03% (due to undercollection in 2017).

6. The cumulative WSIC and SSIC revenue requirements after Aqua's proposed increases/decreases are as follows:

	Previously Approved WSIC/SSIC Revenue Requirement	Net Change To WSIC/SSIC Revenue Requirement	Cumulative WSIC/SSIC Revenue Requirement
Uniform water	$1,558,018	$0	$1,558,018
Uniform sewer	469,664	49,962	519,626
Fairways/Beau Rivage water	41,413	2,319	43,732
Fairways/Beau Rivage sewer	56,759	0	56,759
Brookwood/LaGrange water	249,083	(29,019)	220,064

7. Aqua's additional WSIC/SSIC revenue requirement is comprised of the calculated WSIC/SSIC revenue requirement for the current review period, plus updates to previously approved WSIC/SSIC revenue requirements which became effective on January 1, 2015, and have been updated semiannually through January 1, 2018. The updates include a roll forward of accumulated depreciation and accumulated deferred income taxes. The North Carolina state income tax rate and the NCUC regulatory fee have been set to 3% and 0.14%, respectively. The Federal Corporate Tax Rate has been updated to 21%, which impacts both the overall rate of return and deferred taxes on each previously approved revenue amount. The projected (non WSIC/SSIC) annual service revenue amounts remain at the Company's 2018 projection.

8. Aqua is proposing the above adjustments in the WSIC and SSIC in order to recover the incremental depreciation and capital costs associated with the following WSIC and SSIC projects completed and placed in service from October 1, 2017 through March 31, 2018:

Water main extension	$79,105
Treatment for secondary drinking water standards	345,204
Water main replacement	3,445,818
Total WSIC plant additions	$3,870,127

Replace lift station pumps	$30,560
Replace blowers and/or motors	552,165
Replace headworks	402,148
Total SSIC plant additions	$984,873

9. Under G.S. 62-133.12(c), eligible water system improvements include "equipment and infrastructure installed at the direction of the Commission to comply with secondary drinking water standards." During the six months ended March 31, 2018, Aqua installed one iron and manganese filter system at Well 3 in the Surry Point Subdivision at a total cost of $345,204. The Commission authorized the implementation of this filtration project in its Order Approving Secondary Water Quality Improvement Projects issued on January 18, 2017, in this docket.

10. Pursuant to G.S. 62-133.12(g), the cumulative WSIC and SSIC percentages are capped at 5% of the total annual service revenues approved by the Commission in the Sub 363 Rate Case. The total cumulative WSIC/SSIC revenue requirement calculations for Aqua NC Water, Fairways/Beau Rivage Sewer, and Brookwood/LaGrange Water have exceeded the maximum revenue cap for these entities, therefore the WSIC/SSIC surcharges for this proceeding are based on maximum allowed revenue requirement.

11. As stated by the Commission in its Order adopting Rules R7-39 and R10-26, issued on June 6, 2014, in Docket No. W-100, Sub 54, the Public Staff is to review all infrastructure improvements proposed for recovery for eligibility and reasonableness prior to making its recommendation to the Commission on WSIC or SSIC rate adjustments. Furthermore, any WSIC or SSIC rate adjustments will be allowed to become effective, but not unconditionally approved. These adjustments shall be further examined for a determination of their justness and reasonableness in the Company's next general rate case. At that time, the adjustments may be rescinded retroactively if the Commission determines that the adjustments were not prudent, just, or reasonable.

12. Based on the Public Staff's investigation to date, the Public Staff believes that the WSIC and SSIC projects included in Aqua's request are eligible water and sewer system improvements as defined in G.S. 62-133.12(b), (c), and (d).

13. The Public Staff recommended that the cumulative WSIC and SSIC percentages proposed by Aqua be implemented effective for service rendered on or after July 1, 2018, subject to true-up. The Public Staff stated that it would continue to review the justness, prudency, and reasonableness of these improvements during its review of Aqua's future WSIC and SSIC filings and in Aqua's next general rate case.

CONCLUSIONS

Based upon the foregoing, the Commission concludes that Aqua should be allowed to implement its proposed adjustments in the WSIC and SSIC percentages effective for service rendered on and after July 1, 2018. These WSIC or SSIC rate adjustments, while allowed to become effective, are not unconditionally approved, and will be subject to further examination for justness and reasonableness in the WSIC and SSIC annual review and reconciliation and Aqua's next general rate case.

IT IS, THEREFORE, ORDERED as follows:

1. That Aqua is authorized to implement the recommended Water and Sewer System Improvement Charges set forth in the attached Appendix A to Aqua's Schedule of Rates effective for service rendered on and after July 1, 2018, subject to true-up. The rates contained therein are provisional and subject to review in Aqua's next general rate case.

2. That the attached Appendix A is approved and is deemed filed with the Commission pursuant to G.S. 62-138.

3. That Aqua shall mail to each of its customers with the next regularly scheduled customer billing the Commission-approved customer notice.[1]

4. That Aqua shall submit to the Commission the attached Certificate of Service, properly signed and notarized, no later than 45 days after the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of June, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

APPENDIX A

AQUA NORTH CAROLINA, INC.
WATER AND SEWER SYSTEM IMPROVEMENT CHARGES

WATER SYSTEM IMPROVEMENT CHARGE

All Aqua NC water systems except as noted below	4.75% [1/]
Water systems in Brookwood and LaGrange service areas	4.71% [1/]
Water systems in Fairways and Beau Rivage service areas	4.43% [1/]
Glennburn, Knollwood, and Wimbledon systems in Gaston County	None [2/]

[1] Three separate customer notices are attached hereto as Attachments A, B, and C, respectively. The separate customer notices are intended to minimize customer confusion. Aqua shall mail the appropriate customer notice to each of its customers with the next regular customer billing.

Thornton Ridge/Timberlake system in Alamance County	None [3/]
Clear Meadow system in Mecklenburg County	None [3/]

SEWER SYSTEM IMPROVEMENT CHARGE

All Aqua NC sewer systems except as noted below	3.99% [4/]
Sewer systems in Fairways and Beau Rivage service areas	4.53% [4/]

[1/] The Water System Improvement Charge will be applied to the total water utility bill of each customer under the Company's applicable rates and charges.

[2/] These water systems, which were acquired from Wayne M. Honeycutt in Docket No. W-218, Sub 385, are not included under Aqua's uniform rates and improvements made in these systems, and are not eligible for Water System Improvement Charge recovery.

[3/] These water systems were acquired by Aqua subsequent to Aqua's last general rate case and are not included in Aqua's uniform rates.

[4/] The Sewer System Improvement Charge will be applied to the total sewer utility bill of each customer under the Company's applicable rates and charges.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-218, Sub 363A, on this the 26th day of June, 2018.

ATTACHMENT A
PAGE 1 OF 2

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-218, SUB 363A

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Aqua North Carolina, Inc.,	)	
202 MacKenan Court, Cary, North Carolina	)	NOTICE TO CUSTOMERS IN
27511, for Approval of Semiannual		BROOKWOOD / LAGRANGE
Adjustments to Water and Sewer System	)	SERVICE AREAS
Improvement Charges pursuant to	)	
G.S. 62-133.12	)	

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission (Commission) has issued an Order dated June 26, 2018, pursuant to G.S. 62-133.12 and Commission Rules R7-39 and R10-26, authorizing Aqua North Carolina, Inc. (Aqua), to decrease the Water System Improvement Charge (WSIC) effective for service rendered on and after July 1, 2018, in Aqua's Brookwood/LaGrange service areas in Cumberland and Hoke Counties, in North Carolina.

By Order entered in Docket No. W-218, Sub 363, on May 2, 2014, the Commission approved Aqua's request, pursuant to G.S. 62-133.12, for authority to implement a semiannual WSIC/SSIC adjustment mechanism designed to recover the incremental costs associated with eligible investments in certain water and sewer infrastructure improvement projects completed and placed in service between general rate case proceedings. The WSIC/SSIC mechanism is subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC/SSIC mechanism may not exceed 5% of the total annual service revenues approved by the Commission in Aqua's last general rate case. WSIC and SSIC charges for Aqua were first approved by the Commission on December 22, 2014, effective January 1, 2015. The WSIC and SSIC procedures allow for semiannual adjustments to Aqua's rates every January 1 and July 1. On October 31, 2014, Aqua filed for its first semiannual adjustment to the WSIC and SSIC charges to be effective January 1, 2015.

ATTACHMENT A
PAGE 2 OF 2

The Public Staff carefully reviewed Aqua's proposed WSIC, including a review of invoices, materials lists, work orders, employee timesheets, and other accounting records. On June 11, 2018, the Public Staff filed a Notice of Public Staff's Plan to Present Comments and Recommendations at the Commission's June 25, 2018 Regular Staff Conference (Notice).

Based on the application filed by Aqua and the Public Staff's Notice and recommendations, the Commission has approved the following decrease in the WSIC charge for the Brookwood and LaGrange service areas, effective for service rendered on and after July 1, 2018:

	Previously Approved WSIC Percentage	Net Change To WSIC Percentage	Cumulative WSIC Percentage
WSIC	5.39%	-0.68%	4.71%

The WSIC percentage of 4.71% will be applied to the water utility bill of each customer under Aqua's applicable service rates and charges.

The cumulative 4.71% WSIC percentage results in a $1.43 increase to the monthly average residential bill for a customer using the average of 5,817 gallons per month.

Additional information regarding the WSIC/SSIC mechanism is contained in the Commission's Order dated May 2, 2014, in Docket No. W-218, Sub 363, the Commission's Order Adopting Rules to Implement G.S. 62-133.12, dated June 6, 2014, in Docket No. W-100, Sub 54, the Aqua NC WSIC/SSIC Application filed May 1, 2018, the June 11, 2018, Public Staff Notice, and the June 26, 2018 Commission Order in Docket No. W-218, Sub 363A, all of which can be accessed from the Commission's website at www.ncuc.net, under Docket Portal, using the Docket Search feature for the docket numbers stated above (i.e., for Docket No. key: W-218 Sub 363A).

Parties interested in receiving notice of these filings may subscribe to the Commission's electronic notification system through the Commission's website at www.ncuc.net.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of June, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

ATTACHMENT B
PAGE 1 OF 3

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-218, SUB 363A

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Aqua North Carolina, Inc.,	)	
202 MacKenan Court, Cary, North Carolina	)	NOTICE TO CUSTOMERS
27511, for Approval of Semiannual Adjustments	)	IN FAIRWAYS AND BEAU
to Water and Sewer System Improvement	)	RIVAGE SERVICE AREAS
Charges pursuant to G.S. 62-133.12	)	

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission (Commission) has issued an Order dated June 26, 2018, pursuant to G.S. 62-133.12 and Commission Rules R7-39 and R10-26, authorizing Aqua North Carolina, Inc. (Aqua), to increase the Water System Improvement Charge (WSIC) and to keep constant the current Sewer System Improvement Charge (SSIC) effective for service rendered on and after July 1, 2018, in Aqua's Fairways and Beau Rivage service areas in New Hanover County, North Carolina.

By Order entered in Docket No. W-218, Sub 363, on May 2, 2014, the Commission approved Aqua's request, pursuant to G.S. 62-133.12, for authority to implement a semiannual WSIC/SSIC adjustment mechanism designed to recover the incremental costs associated with eligible investments in certain water and sewer infrastructure improvement projects completed and placed in service between general rate case proceedings. The WSIC/SSIC mechanism is subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC/SSIC mechanism may not exceed 5% of the total annual service revenues approved by the Commission in Aqua's last general rate case. WSIC and SSIC charges for Aqua were first approved by the Commission on December 22, 2014, effective January 1, 2015. The WSIC and SSIC procedures allow for semiannual adjustments to Aqua's rates every January 1 and July 1. On October 31, 2014, Aqua filed for its first semiannual adjustment to the WSIC and SSIC charges to be effective January 1, 2015.

ATTACHMENT B
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The Public Staff carefully reviewed Aqua's stated WSIC and SSIC improvements, including a review of invoices, materials lists, work orders, employee timesheets, and other accounting records. On June 11, 2018, the Public Staff filed a Notice of Public Staff's Plan to Present Comments and Recommendations at the Commission's June 25, 2018 Regular Staff Conference (Notice).

Based on the application filed by Aqua and the Public Staff's Notice and recommendations, the Commission has approved the following increase in the WSIC and no change in the SSIC for the Fairways and Beau Rivage service areas, effective for service rendered on and after July 1, 2018:

	Previously Approved WSIC/SSIC Percentage	Net Change To WSIC/SSIC Percentage	Cumulative WSIC/SSIC Percentage
WSIC	4.27%	0.16%	4.43%
SSIC	4.53%	0.00%	4.53%

The WSIC percentage of 4.43% will be applied to the water utility bill of each customer, and the SSIC percentage of 4.53% will be applied to the sewer utility bill of each customer, under Aqua's applicable service rates and charges.

The 4.43% WSIC percentage results in an $0.86 increase to the monthly average residential bill for a customer using the average of 7,655 gallons per month. The 4.43% WSIC percentage also will apply to the monthly bills for the customers on water systems where Aqua purchases bulk water.

The cumulative SSIC percentage of 4.53% will be applied to the sewer utility bill of each customer under Aqua's applicable service rates and charges. The cumulative 4.53% SSIC percentage results in a $1.65 increase to the monthly residential customer flat rate sewer bill.

Additional information regarding the WSIC/SSIC mechanism is contained in the Commission's Order dated May 2, 2014, in Docket No. W-218, Sub 363, the Commission's Order Adopting Rules to Implement G.S. 62-133.12, dated June 6, 2014, in Docket No. W-100, Sub 54, the Aqua NC WSIC/SSIC Application filed May 1, 2018, the June 11, 2018, Public Staff Notice, and the June 26, 2018 Commission Order in Docket No. W-218, Sub 363A, all of which can be accessed from the Commission's website at www.ncuc.net, under Docket Portal, using the Docket Search feature for the docket numbers stated above (i.e. for Docket No. key: W-218 Sub 363A).

ATTACHMENT B
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Parties interested in receiving notice of these filings may subscribe to the Commission's electronic notification system through the Commission's website at www.ncuc.net.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of June, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

ATTACHMENT C
PAGE 1 OF 3

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-218, SUB 363A

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Aqua North Carolina, Inc., 202	)	
MacKenan Court, Cary, North Carolina 27511,	)	NOTICE TO CUSTOMERS
for Approval of Semiannual Adjustments to	)	IN AQUA NORTH CAROLINA
Water and Sewer System Improvement	)	UNIFORM RATES SERVICE AREAS
Charges pursuant to G.S. 62-133.12	)	

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission (Commission) has issued an Order dated June 26, 2018, pursuant to G.S. 62-133.12 and Commission Rules R7-39 and R10-26, authorizing Aqua North Carolina, Inc. (Aqua), to decrease the Water System Improvement Charge (WSIC) and to increase the Sewer System Improvement Charge (SSIC) effective for service rendered on and after July 1, 2018, in its service areas in North Carolina.

By Order entered in Docket No. W-218, Sub 363, on May 2, 2014, the Commission approved Aqua's request, pursuant to G.S. 62-133.12, for authority to implement a semiannual WSIC/SSIC adjustment mechanism designed to recover the incremental costs associated with eligible investments in certain water and sewer infrastructure improvement projects completed and placed in service between general rate case proceedings. The WSIC/SSIC mechanism is subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC/SSIC mechanism may not exceed 5% of the total annual service revenues approved by the Commission in Aqua's last general rate case. WSIC and SSIC for Aqua were first approved by the Commission on December 22, 2014, effective January 1, 2015.

The WSIC and SSIC procedures allow for semiannual adjustments to Aqua's rates every January 1 and July 1. On October 31, 2014, Aqua filed for its first semiannual adjustment to the WSIC and SSIC charges to be effective January 1, 2015.

ATTACHMENT C
PAGE 2 OF 3

The Public Staff carefully reviewed Aqua's stated WSIC and SSIC improvements, including a review of invoices, materials lists, work orders, employee timesheets, and other accounting records. On June 11, 2018, the Public Staff filed a Notice of Public Staff's Plan to Present Comments and Recommendations at the Commission's June 25, 2018 Regular Staff Conference (Notice).

Based on the application filed by Aqua and the Public Staff's Notice and recommendations, the Commission has approved the following adjustments in the WSIC and SSIC charges, effective for service rendered on and after July 1, 2018:

	Previously Approved WSIC/SSIC Percentage	Net Change To WSIC/SSIC Percentage	Cumulative WSIC/SSIC Percentage
WSIC	4.77%	-0.02%	4.75%
SSIC	3.59%	0.40%	3.99%

The WSIC percentage of 4.75% will be applied to the water utility bill of each customer, and the SSIC percentage of 3.99% will be applied to the sewer utility bill of each customer, under Aqua's applicable service rates and charges.

The cumulative 4.75% WSIC percentage results in a $2.18 increase to the monthly average residential bill for a customer using the average of 5,170 gallons per month. The cumulative 4.75% WSIC percentage also will apply to the monthly bills for the customers on water systems where Aqua purchases bulk water.

The cumulative 3.99% SSIC percentage results in a $2.59 increase to the monthly residential flat rate sewer bill. The cumulative 3.99% SSIC percentage will also apply to the monthly metered bills for customers on sewer systems where Aqua purchases bulk sewer treatment.

Additional information regarding the WSIC/SSIC mechanism is contained in the Commission's Order dated May 2, 2014, in Docket No. W-218, Sub 363, the Commission's Order Adopting Rules to Implement G.S. 62-133.12, dated June 6, 2014, in Docket No. W-100, Sub 54, the Aqua NC WSIC/SSIC Application filed May 1, 2018, the June 11, 2018, Public Staff Notice, and the June 26, 2018 Commission Order in Docket No. W-218, Sub 363A, all of which can be accessed from the Commission's website at www.ncuc.net, under Docket Portal, using the Docket Search feature for the docket numbers stated above (i.e. for Docket No. key: W-218 Sub 363A).

ATTACHMENT C
PAGE 3 OF 3

Parties interested in receiving notice of these filings may subscribe to the Commission's electronic notification system through the Commission's website at www.ncuc.net.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of June, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

CERTIFICATE OF SERVICE

I, ______________________________, mailed with sufficient postage or hand delivered to all affected customers the attached Notices to Customers issued by the North Carolina Utilities Commission in Docket No. W-218, Sub 363A, and the Notices were mailed or hand delivered by the date specified in the Order.

This the _____ day of ________________, 2018.

By: ______________________________
Signature

____
Aqua North Carolina, Inc.

The above named Applicant, ________________________________, personally appeared before me this day and, being first duly sworn, says that the required Notice to Customers was mailed or hand delivered to all affected customers, as required by the Commission Order dated ____________________ in Docket No. W-218, Sub 363A.

Witness my hand and notarial seal, this the ____ day of ______________, 2018.

____
Notary Public

____
Typed or Printed Name

(SEAL) My Commission Expires: ______________________________
Date

DOCKET NO. W-218, SUB 363A

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Reporting Requirements from Docket No. W-218, Sub 363 – Application by Aqua North Carolina, Inc., 202 MacKenan Court, Cary, North Carolina 27511, for Approval to Implement Secondary Water Quality System Improvement Projects Pursuant to N.C. Gen. Stat. § 62-133.12	)))))))	ORDER APPROVING SECONDARY WATER QUALITY IMPROVEMENT PROJECTS

BY THE COMMISSION: N.C. Gen. Stat. § 62-133.12 authorizes the Commission in a general rate case proceeding to approve a rate adjustment mechanism to allow water and sewer utilities to recover the incremental depreciation expense and capital costs associated with reasonable and prudently incurred investments in eligible water and sewer system improvements By Order issued May 2, 2014 in Docket No. W-218, Sub 363, the last general rate case proceeding for Aqua North Carolina, Inc. (Aqua), the Commission approved Aqua's request to utilize a Water System Improvement Charge/Sewer System Improvement Charge (WSIC/SSIC) mechanism pursuant to N.C. Gen. Stat. § 62-133.12, finding that the mechanism is in the public interest.

Commission Rules R7-39(f) and R10-26(f) provide that once WSIC and SSIC mechanisms are approved and eligible water and sewer system improvements are in service, the utility (in this case, Aqua) may file a request with the Commission for authority to impose water and sewer system improvement charges pursuant to the mechanisms.

N.C. Gen. Stat. § 62-133.12(c)(2) and (c)(4) provide, in pertinent part, that specific approval from the Commission is necessary before Aqua may undertake and recover its incremental depreciation expense and capital costs through the WSIC mechanism for eligible water system improvements implemented to comply with secondary drinking water standards.

On August 14, 2018 and October 24, 2018, Aqua filed an application for approval to implement four secondary water quality system improvement projects pursuant to N.C. Gen. Stat. § 62-133.12 and Commission Rule R7-39. The four projects and their estimated costs are summarized below.

System	County	Well Gallons Per Minute	Aqua Estimated Cost 000's
Georges Grant Well 1	Wake	68	$350-$375
The Barony Well 5	Wake	77	$350-$375
Upchurch Place Wells 1 & 4	Wake	89	$350-$375
Woodvalley Well 9	Wake	38	$275-$300
		Total	$1.325-$1.425 Million

WATER AND SEWER -- FILINGS DUE PER ORDER

On November 9, 2018, the Public Staff filed its Report and Recommendations regarding Aqua's application. The Public Staff stated that it had thoroughly reviewed the four filter projects proposed by Aqua. Based upon its review of documents and other information provided by Aqua, site visits, and discussions with customers and Aqua's engineers and operations managers, the Public Staff recommended that the Commission approve the proposed projects.

In recommending approval of the projects, the Public Staff advised that decisions to install filters, such as manganese greensand or magnesium oxide, be made judiciously, as installation of such filters is many times more costly than sequestration coupled with adequate flushing. According to the Public Staff, the annual revenue requirement increase for the minimum estimated capital expenditure of $1,325,000 for the filtration systems proposed in Aqua's application is approximately $170,925 compared to the annual revenue requirement for the chemical cost for sequestration of approximately $1,268. The Public Staff stated that the sequestration treatment of iron and manganese with polyphosphates and orthophosphates on water from North Carolina water wells, coupled with comprehensive water main flushing programs, has largely provided adequate secondary standard water quality on many water systems at a very reasonable cost. The process of testing whether the iron and manganese are soluble (clear liquid) or insoluble (solid particles and visible) in raw untreated water at the well head, after treatment with polyphosphate/orthophosphate or SeaQuest® at the entry point, and in the distribution system, has been widely used in North Carolina for many years and provides extremely valuable information to assist in evaluations of whether filtration is necessary. These treatment processes are exponentially less expensive than an iron and manganese filtration system. The Public Staff recognized, however, that for secondary water quality issues of considerable magnitude and consistency, sequestration treatment and flushing may not be effective and may necessitate filtration.

As discussed in previous reports, the Public Staff strongly supports the implementation of two additional secondary water quality processes: a comprehensive water main flushing program and a comprehensive customer education program. The Public Staff recommended that Aqua continue to upgrade its flushing program. Regarding customer education, the Public Staff noted that with its input, Aqua has prepared and posted on its website (https://www.aquaamerica.com/our-states/north-carolina.aspx) a fact sheet titled "Flushing Water Mains," and a best practices document titled "Iron and Manganese in Drinking Water". According to Aqua, these documents have been made available to its employees to distribute to customers they may visit who experience a discolored water issue. The Public Staff stated that it considers the documents to be useful resources to help customers better understand flushing and minimize the negative effects of discolored water caused by the presence of iron and manganese. The Public Staff stated that Aqua most recently created the dedicated website www.ncwaterquality.com as a means for the Company to provide information to customers pertaining to iron and manganese. In addition, as part of Aqua's Water Quality Plan, the Company has begun a strategic communications initiative.

In summary, the Public Staff stated that it will continue to carefully and thoroughly review secondary water quality information and documentation presented by Aqua, meet with Aqua engineers and operations managers, conduct selected site visits, discuss secondary water quality issues with customers, and recommend, when appropriate, Commission approval of equipment and infrastructure installations.

WATER AND SEWER – FILINGS DUE PER ORDER

The Public Staff presented this matter to the Commission at its Staff Conference on November 19, 2018. The Public Staff stated that each of the filters is necessary for Aqua to provide adequate secondary standard water quality. The Public Staff therefore recommended that the Commission approve Aqua's four proposed secondary standard water quality projects.

Based upon the foregoing, Aqua's application, the Public Staff's Report and Recommendations, and the entire record in this matter, the Commission finds and concludes that Aqua should proceed to implement secondary standard water quality improvements through the installation of Aqua's proposed filtration projects.

IT IS, THEREFORE, ORDERED that Aqua is authorized to implement the four filtration projects proposed in its August 14, 2018 and October 24, 2018, applications to comply with secondary water quality standards.

ISSUED BY ORDER OF THE COMMISSION.
This the 20th day of November, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

Commissioner Lyons Gray did not participate in this decision.

DOCKET NO. W-1049, SUB 23

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Public Staff – North Carolina Utilities Commission, Complainant v. A&D Water Services, Inc., Respondent	)))))))	ORDER GRANTING EMERGENCY MOTION

BY THE CHAIRMAN: On September 13, 2018, the Public Staff – North Carolina Utilities Commission (Public Staff) filed a Motion Requesting Emergency Relief (Motion) in the above-captioned proceeding. In the motion, the Public Staff informs the Commission that A&D Water Services, Inc. (A&D) unlawfully terminated water service to at least three customers of a subdivision in Sapphire, Transylvania County, North Carolina. The Public Staff further states that it has spoken with Aubrey Deaver, the owner and operator of A&D, who states that he is having problems with the developer of the subdivision and terminated water service to the developer and the subdivision.

Rule 7-20(c) of the Rules Governing Water Utilities states:

> Notice of Discontinuance. — No utility shall discontinue service to any customer for violation of its rules or regulations without first having diligently tried to induce the customer to comply with its rules and regulations. After such effort on the part of the utility, service may be discontinued only after written notice of such intention, and that five (5) days, excluding Sundays and holidays, shall have been given the customer by the utility; provided, however, that where an emergency exists, or where fraudulent use of water is detected, or where a dangerous condition is found to exist on the customer's premises, the water may be shut off without such notice.

Rule 7-20(d) of the Rules Governing Water Utilities states:

> Disputed Bills. — In the event of a dispute between the customer and the utility respecting any bill, the utility shall make forthwith such investigation as shall be required by the particular case, and report the result thereof to the customer. In the event that the matter in dispute cannot be compromised or settled by the parties, either party may submit the fact to the Commission for its opinion, and pending such opinion, service shall not be discontinued.

The Chairman recognizes that A&D is a public utility providing water utility service to more than 15 customers. According to Commission records, A&D was granted a franchise to provide water utility service in the Sapphire Subdivision (now Burlingame Subdivision) in Docket No. W-1049, Sub 6 (2005). The Chairman understands that three of the customers receive water service and pay its bills to A&D. The Commission has reached out to A&D by telephone to find out more information about the reason why the customers were disconnected. A&D has confirmed that its dispute is solely with a developer and not with the customers. A&D, however, still disconnected the water extension which serves the customers in question. If true, A&D has terminated utility service to its customers without notice and in violation of Commission Rule R7-20. The Chairman further recognizes that Hurricane Florence is scheduled to hit the coastal areas of the state of North Carolina within the next 48-72 hours and travel across the state delivering heavy rain and wind. The National Meteorologists' Association is suggesting the state may endure falling trees resulting in possible power outages. The denial of utility service in the face of a pending Hurricane could mean an emergency and a significant hardship for the A&D customers. The Chairman points out that N. C. Gen. Stat. § 62-118(b) defines an emergency as the imminent danger of losing adequate water or sewer utility service or the actual loss thereof. By disconnecting the aforementioned customers who have duly paid their bills for service without cause and in violation of the Commission rules, it appears that the utility has created an emergency as the term is defined in N.C. Gen. Stat. § 62-118(b). Despite this information, A&D has informed the Commission that it will not reconnect service to that area until matters are resolved between it and the developer.

Based on the foregoing, the Chairman finds that good cause exists to grant the Public Staff's motion. The Chairman further informs A&D that if it does not adhere to the Commission's order and continues to deny utility service to said customers it may be fined a sum up to one thousand dollars ($1,000) a day pursuant to N.C. Gen. Stat. § 62-310 enforceable by N.C. Gen. Stat. § 312. Additionally, the Commission may pursuant to N.C. Gen. State § 62-118(b) seek action in Transylvania County Superior Court to appoint an emergency operator of such water or sewer utility service.

IT IS THEREFORE, ORDERED that A&D Water Service, Inc., immediately restore service to all customers in the subdivision.

ISSUED BY ORDER OF THE COMMISSION.
This the 13th day of September, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. W-218, SUB 497

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Aqua North Carolina, Inc., 202 MacKenan Court, Cary, North Carolina 27511, for Authority to Adjust and Increase Rates for Water and Sewer Utility Service in All Service Areas in North Carolina	))))))	ORDER APPROVING PARTIAL SETTLEMENT AGREEMENT AND STIPULATION, GRANTING PARTIAL RATE INCREASE, AND REQUIRING CUSTOMER NOTICE

HEARD: Tuesday, May 8, 2018, at 7:00 p.m., Davie County Courthouse, District Courtroom, 140 South Main Street, Mocksville, North Carolina

Wednesday, May 9, 2018, at 7:00 p.m., Gaston County Courthouse, Courtroom 4C, 325 Dr. Martin Luther King Jr. Way, Gastonia, North Carolina

Monday, June 25, 2018, at 7:00 p.m., Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Tuesday, June 26, 2018, at 7:00 p.m., New Hanover County Courthouse, Courtroom 317, 316 Princess Street, Wilmington, North Carolina

Tuesday, September 11, 2018, at 1:30 p.m., and continuing as required through Tuesday, September 25, 2018, in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding; Chairman Edward S. Finley, Jr., and Commissioners Jerry C. Dockham, James G. Patterson, Lyons Gray, Daniel G. Clodfelter, and Charlotte A. Mitchell

APPEARANCES:

For Aqua North Carolina, Inc.:

Jo Anne Sanford, Sanford Law Office, PLLC, Post Office Box 28085, Raleigh, North Carolina 27611

Robert H. Bennink, Jr., Bennink Law Office, 130 Murphy Drive, Cary, North Carolina 27513

Dwight Allen, Britton Allen, and Brady Allen, Allen Law Offices, PLLC, 1514 Glenwood Avenue, Suite 200, Raleigh, North Carolina 27612

For Eric Galamb (pro se):

Eric Galamb, 12208 Glenlivet Way, Raleigh, North Carolina 27616

For the Using and Consuming Public:

William E. Grantmyre, Elizabeth D. Culpepper, and Megan Jost, Staff Attorneys, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699

Margaret A. Force, Assistant Attorney General, and Teresa Townsend, Special Deputy Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602

BY THE COMMISSION: On February 5, 2018, pursuant to Commission Rule R1-17(a), Aqua North Carolina, Inc. (Aqua NC or the Company) submitted notice of its intent to file a general rate case application.

On March 7, 2018, Aqua NC filed its verified application for a general rate increase (Application), seeking authority to: (1) increase and adjust its rates for water and sewer utility service in all of its service areas in North Carolina; (2) pass through to rates any increases in purchased bulk water rates, subject to Aqua NC providing sufficient proof of the increases, as well as any increased costs of wastewater treatment performed by third parties and billed to Aqua NC; and (3) increase certain other charges. Included with this filing were certain information and data required by NCUC Form W-1. The Company stated in its Application that it serves approximately 78,739 water customers and 17,940 sewer customers in North Carolina.

In Docket No. W-218, Sub 363 (Aqua NC's last general rate case), the Commission issued on May 2, 2014, an Order Granting Partial Rate Increase, Approving Rate Adjustment Mechanism, and Requiring Customer Notice. Except for approved tariff revisions to the rates of bulk purchased water and/or sewer systems, the present rates for water and sewer service have been in effect since January 1, 2017, pursuant to the Commission's December 20, 2016 Order Approving Tariff Revision and Customer Notice issued in Docket Nos. W-218, Sub 363; M-100, Sub 138; and M-100, Sub 142. The present Water and Sewer System Improvement Charges (WSIC/SSIC) have been in effect since January 1, 2018, pursuant to the Commission's December 18, 2017 Order Approving Water and Sewer System Improvement Charges on a Provisional Basis and Requiring Customer Notice issued in Docket No. W-218, Sub 363A.

On April 2, 2018, Aqua NC filed its Ongoing Three-Year WSIC/SSIC Plan in this docket.

On April 5, 2018, the Commission issued an Order Establishing General Rate Case, Suspending Rates, Scheduling Hearings, and Requiring Public Notice. By that Order, the Commission declared the matter to be a general rate case pursuant to N.C.G.S. § 62-137, suspended the proposed new rates for up to 270 days pursuant to N.C.G.S. § 62-134, required the parties to prefile testimony and exhibits, scheduled the matter for hearing, and required notice to all affected customers. The Order also scheduled customer hearings in Mocksville, Gastonia, Raleigh, and Wilmington, North Carolina, and set the evidentiary hearing in Raleigh, North Carolina. Additionally, the Order required Aqua NC to file reports addressing all customer service and/or service quality complaints expressed at the public hearings within 20 days of each respective hearing.

On April 6, 2018, the Commission issued an Errata Order correcting inadvertent errors contained in Appendix C of its April 5, 2018 Order.

On April 23, 2018, Aqua NC filed its certificate of service of the customer notice as required by the Commission.

On June 8, 2018, Aqua NC filed the direct testimony and exhibits of John J. Spanos, Senior Vice President, Gannett Fleming Valuation and Rate Consultants, LLC. The exhibits included depreciation studies of Aqua NC's water and wastewater plant assets as of September 30, 2017.

Public hearings were held as scheduled. The following public witnesses testified at the public hearings held in this proceeding:

May 8, 2018	Mocksville	None
May 9, 2018	Gastonia	Steve Gordon, Ashley Norris
June 25, 2018	Raleigh	Representative Joseph R. John, Sr., Rebecca Daniel, Rich Vitale, Debra Cook, Reece Dillard, Darlene Kinsey, Pat Fleming, Melissa Mitchell, Don Hess, Shannon Brien, Mark Sullivan, Susie Holmes, Kristina Heinz, Peter Jogodka, Michael Dowd, Ralph Sandle, Aimee Bickers, Robert Strazis, Chris Jones, Jack Robinson
June 26, 2018	Wilmington	Joseph Napoli, Guenter Kass, David Hough, Ronald Hess, Michael Smith, Dan Graney

Aqua NC responded to public witness testimony by its filings of May 29, July 16, and July 20, 2018.

On July 27, 2018, Aqua NC filed the direct testimony and exhibits of Shannon V. Becker, President, Aqua NC; Dr. Christopher Crockett, Chief Environmental Officer, Aqua America, Inc.[1] (Aqua America); Dylan W. D'Ascendis, Director, ScottMadden, Inc.; Dean R. Gearhart, Manager of Rates and Planning, Aqua NC; and Robert A. Kopas, Consultant, Aqua Services, Inc.[2]

On August 6, 2018, Aqua NC filed the revised direct testimony of its witness Kopas.

[1] Aqua NC is a wholly-owned subsidiary of Aqua America, Inc.

[2] Mr. Kopas retired from his position as Regional Controller for Aqua Services, Inc. on July 1, 2018. Following his retirement, Mr. Kopas served as a consultant through the conclusion of the proceedings in this docket. Tr. Vol. 5, p. 240.

On August 10, 2018, the North Carolina Attorney General's Office (AGO) filed a notice of intervention in this proceeding. The Commission recognizes the AGO's intervention pursuant to N.C.G.S. § 62-20.

The Public Staff's participation in this proceeding is recognized pursuant to N.C.G.S. § 62-15(d) and Commission Rule R1-19.

On August 20, 2018, Eric Galamb, an Aqua NC customer, filed a motion to intervene, including as attachments his proposed direct testimony and exhibits.

On August 21 and 22, 2018, the Public Staff filed the direct testimony and exhibits of Windley E. Henry, Accounting Manager, Water/Communications Section, Public Staff Accounting Division; Manasa L. Cooper, Staff Accountant, Public Staff Accounting Division; Charles Junis, Utilities Engineer, Public Staff Water, Sewer, and Telephone Division; Lindsay Darden, Utilities Engineer, Public Staff Water, Sewer, and Telephone Division; and John R. Hinton, Director, Public Staff Economic Research Division.

On August 24, 2018, Aqua NC responded to Eric Galamb's motion to intervene, arguing that Mr. Galamb's motion "actually presents a service quality complaint," and requesting that the Commission deny Mr. Galamb's motion and direct Mr. Galamb, Aqua NC, and the Public Staff "to attempt to resolve [Mr. Galamb's] complaint and report back to the Commission by a date-certain."

On August 30, 2018, Aqua NC filed a motion for extension of time to file its rebuttal testimony until September 4, 2018. Aqua NC also moved to postpone the start of the evidentiary hearing to September 11, 2018, at 1:30 p.m. These motions were granted by Commission Order of August 31, 2018.

Also on August 31, 2018, the Commission issued an Order granting, for the limited purpose of addressing whether Aqua NC's application for a general rate increase is supported by sufficient evidence, Mr. Galamb's motion to intervene in this proceeding.

On September 4, 2018, Aqua NC filed the rebuttal testimony and exhibits of its witnesses Becker; Gearhart; D'Ascendis; Kopas; Amanda Berger, Manager of Environmental Compliance, Aqua NC; Joseph Pearce, Director of Operations, Aqua NC; and Bernard F. Thompson, Director of Procurement, Aqua Services, Inc.

On September 5, 2018, the Public Staff filed the testimony and exhibits of Michelle M. Boswell, Staff Accountant, Public Staff Accounting Division, and the supplemental testimony and exhibits of its witnesses Henry, Cooper, and Junis.

On September 6, 2018, Aqua NC filed a motion requesting that the Commission enter an order excusing Company witness John J. Spanos from appearing at the evidentiary hearing, and requesting that witness Spanos' testimony and exhibits be admitted into the record as if given orally from the stand. By Order entered that same day, the Commission granted Aqua NC's motion to excuse witness Spanos.

Also on September 6, 2018, Aqua NC filed a motion to strike a portion of the prefiled direct testimony of Public Staff witness Junis. The Public Staff filed a response in opposition to Aqua NC's Motion to Strike on September 7, 2018.

On September 7, 2018, Aqua NC filed the supplemental rebuttal testimony of witness Becker.

On September 11, 2018, the Public Staff filed a motion to recess the evidentiary hearing due to Hurricane Florence, which was expected to impact Raleigh later that week.

The evidentiary hearing began as scheduled at 1:30 p.m. on September 11, 2018, in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina. Thereafter, the evidentiary hearing continued as necessary until its conclusion on Tuesday, September 25, 2018.

Prior to the presentation of testimony, the Commission denied Aqua NC's pending motion to strike. Thereafter, Mr. Galamb presented his direct testimony. Aqua NC presented the direct testimony of its witnesses Becker, Kopas, and Gearhart, and the direct and rebuttal testimony of its witness D'Ascendis. The Public Staff presented the direct testimony of its witness Hinton. The hearing was adjourned at 11:38 a.m. on September 12, 2018, due to the expected impact of Hurricane Florence.

On September 12, 2018, the Public Staff filed revised Exhibits 1 and 3 of its witness Boswell and refiled Boswell Exhibit 2.

On September 12, 2018, as requested by Presiding Commissioner Brown-Bland, the AGO filed copies of its communications with the North Carolina Department of Environmental Quality (DEQ) concerning Aqua NC.

On September 13, 2018, the Public Staff filed a motion requesting that the Commission issue an order ruling that excerpts of an audio recording made by Company witness Berger not be treated as confidential, and requesting that they be accepted into evidence.

Also on September 13, 2018, the Public Staff filed the revised supplemental exhibits of its witnesses Cooper and Henry.

On September 17, 2018, Aqua NC and the Public Staff entered into and filed a Partial Settlement Agreement and Stipulation (Stipulation). The Stipulation resolved some of the contested issues between Aqua NC and the Public Staff (Stipulating Parties) in this proceeding. However, the following disputed issues remained: (1) Return on Equity; (2) the Public Staff's removal of 50% of four Company operators' salaries and related benefits; (3) the Public Staff's reduction of executive compensation and benefits by 50%; (4) the Public Staff's reduction of Board of Director fees by 50%; (5) annualization and consumption adjustments; (6) post-test year plant additions; (7) the Public Staff's removal of 30% of bonuses paid to Aqua NC supervisory employees; (8) adjustment for Aqua NC's Neuse Colony Wastewater Treatment Plant expansion and capacity payment to Johnston County; (9) adjustment to costs related to Automatic Meter

Reading (AMR) meters and the two meter installation projects; (10) adjustment to excess capacity; (11) adjustment to sludge removal; (12) adjustment to testing; (13) adjustment for water losses from purchased water systems; (14) water quality issues, including reporting and customer complaints; and (15) Consumption Adjustment Mechanism.

The evidentiary hearing reconvened on September 18, 2018, at 10:30 a.m. Aqua NC presented the direct testimony of its witness Crockett and the rebuttal testimony of its witnesses Thompson, Gearhart, Pearce, Becker, and Berger. The Public Staff presented the direct and supplemental testimony of its witnesses Boswell, Darden, Cooper, Henry, and Junis.

On September 18, 2018, Aqua NC filed its response to the Public Staff's motion of September 13, 2018, waiving its claim of confidentiality regarding the audio recording and withdrawing its objection[1] to the recording being admitted into evidence.

On September 19, 2018, Aqua NC made a filing pursuant to requests made on the record during the evidentiary hearing by Presiding Commissioner Brown-Bland and Commissioner Mitchell for late-filed exhibits regarding the Company's communication with DEQ concerning water quality issues.

On October 3, 2018, Aqua NC filed a late-filed exhibit regarding interconnection construction for wastewater capacity purchased from Johnston County in response to a request made on the record during the evidentiary hearing by Commissioner Clodfelter.

On October 4, 2018, Aqua NC filed a late-filed exhibit concerning 2002 bulk wastewater agreement between Johnston County, Flowers Plantation and Heater Utilities, Inc., in response to requests made on the record during the evidentiary hearing by Chairman Finley and Commissioner Clodfelter.

On October 10, 2018, the Public Staff filed certain late-filed exhibits in response to requests made on the record during the evidentiary hearing by Presiding Commissioner Brown-Bland, Chairman Finley, and Commissioner Mitchell.

On October 11, 2018, the Public Staff filed a late-filed exhibit regarding the Flowers Plantation contributions in aid of construction issues in response to requests made on the record during the evidentiary hearing by Commissioner Clodfelter and Chairman Finley. On October 15, 2018, the Public Staff filed a correction to this late-filed exhibit.

On October 12, 2018, Aqua NC filed its third quarter 2018 notice of deficiency reports to DEQ.

On October 22, 2018, Aqua NC filed a motion for extension of time until October 30, 2018, for the parties to file proposed orders in this docket. On October 23, 2018, the Commission issued an Order granting this motion

[1] An objection was raised by Aqua NC in its response to the Public Staff Legal Data Request #1 in follow-up to Engineering Data Request #58.

On October 30, 2018, Aqua NC and the Public Staff filed their respective proposed orders, and the AGO and Intervenor Eric Galamb filed their post-hearing briefs.

On November 6, 2018, the Public Staff filed a late-filed exhibit, as requested during the evidentiary hearing, relating to Aqua America, Inc.'s Executive Compensation and North Carolina Supervisors' Bonuses.

On November 19, 2018, Aqua NC filed the Affidavit of Dean R. Gearhart regarding the Company's requested level of rate case expense.

On November 20, 2018, the Public Staff filed Appendices to its proposed order.

The Public Staff filed its Response to the Company's Affidavit of Dean R. Gearhart on November 26, 2018.

All late-filed exhibits were filed by the parties as requested by the Commission during the evidentiary hearing. No objections were raised to the admission into evidence of any such late-filed exhibits, and, therefore, the Commission hereby accepts such exhibits into the record.

Based on the Company's Application and corresponding NCUC Form W-1, the testimony and exhibits received into evidence at the hearings held in this proceeding, the Stipulation, the late-filed exhibits submitted at the request of the Commission during the evidentiary hearing, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT
General Matters

1. Aqua NC is a corporation duly organized under the laws of North Carolina and is authorized to do business in the State. It is a franchised public utility providing water and/or sewer utility service to customers in North Carolina. Aqua NC is a wholly-owned subsidiary of Aqua America, Inc. (Aqua America), located in Bryn Mawr, Pennsylvania.

2. Aqua NC is subject to the jurisdiction of the Commission pursuant to Chapter 62 of the North Carolina General Statutes for adjudication of Aqua NC's Application for a rate increase and for a determination of the justness and reasonableness of Aqua NC's proposed rates for its water and sewer utility operations in North Carolina.

3. The test period appropriate for use in this proceeding is the 12-month period ending September 30, 2017, updated for known and measurable changes through June 30, 2018, and including up to the close of the evidentiary hearing on September 25, 2018.

4. Aqua NC's last general rate case was decided by Commission Order (Sub 363 Order) entered on May 2, 2014, in Docket No. W-218, Sub 363. Aqua NC's present rates for water and sewer service in all of the Company's service areas have been in effect since January 1, 2017,

pursuant to Commission Order issued on December 20, 2016, in Docket Nos. M-100, Sub 138; M-100, Sub 142; and W-218, Sub 363.[1]

The Stipulation

5. On September 17, 2018, the Stipulating Parties entered into and filed the Stipulation resolving some of the disputed issues between the Stipulating Parties in this proceeding. The issues that were not resolved by the Stipulation are sometimes referred to collectively herein as the Unsettled Issues.

6. The revenue requirement effect of the Stipulation is shown in Settlement Exhibit 1 and Henry Additional Direct Partial Settlement Agreement Exhibit 1, which provide sufficient support for the annual revenue required for the issues resolved by the Stipulation.

7. The Stipulation is the product of the give-and-take in settlement between the Stipulating Parties, is material evidence in this proceeding, and is entitled to be given appropriate weight in this case, along with other evidence from Aqua NC, the Public Staff, and other intervening parties, along with consumer statements of position and the testimony of the public witnesses concerning the Company's Application.

8. The Stipulation settles only some of the disputed issues between the Stipulating Parties. The Unsettled Issues include the return on equity; removal of 50% of four operators' salaries and related benefits; reduction of executive compensation and benefits by 50%; reduction of Board of Director fees by 50%; annualization and consumption adjustments; post-test year plant additions; removal of 30% of bonuses paid to Aqua NC's North Carolina supervisory employees; adjustment for Aqua NC's Neuse Colony Wastewater Treatment Plant sewer expansion and its purchased capacity payment to Johnston County; adjustment to costs related to AMR meters and the two meter installation projects; adjustment to excess capacity; adjustment to sludge removal; adjustment to testing; adjustments for water losses from purchased water systems; water quality issues, including reporting and customer complaints; and the Consumption Adjustment Mechanism proposed by Aqua NC. The Unsettled Issues are resolved by the Commission and addressed in this Order.

Acceptance of Stipulation

9. The Stipulation will provide Aqua NC and its ratepayers just and reasonable rates when combined with the rate effects of the Commission's decisions regarding the Unsettled Issues in this proceeding.

10. The provisions of the Stipulation are just and reasonable to all parties to this proceeding and serve the public interest. Therefore, the Stipulation should be approved in its entirety.

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[1] Pass-through rate increases for various purchased water systems have been approved pursuant to N.C.G.S § 62-133.11, subsequent to the Commission's December 20, 2016 Order.

Customer Concerns – Service and Water Quality-Related Issues

11. As of the date of the evidentiary hearing, Aqua NC served approximately 78,739 water customers and 17,940 wastewater customers. Aqua NC owns and operates 750 systems consisting of over 1,400 wells and 59 wastewater treatment plants in 51 counties in North Carolina.

12. A total of 28 customers testified at the four separate public hearings held in Mocksville, Gastonia, Raleigh, and Wilmington for the purpose of receiving customer testimony.[1] In general, public testimony received at those hearings covered water quality concerns, customer service concerns, and opposition to rate increases.

13. Customer witnesses testifying regarding water quality complained specifically about poor water quality, badly discolored water, sediment buildup related to iron and manganese concentrations in the water, damage to appliances and discoloration of laundry and household fixtures caused by poor water quality, and unsatisfactory customer service related to Aqua NC's responsiveness and dissemination of inaccurate and insufficient information regarding such matters as water flushing and service outages. Many customers complaining of water quality issues testified that they do not drink the water supplied by Aqua NC systems to their taps and, instead, have resorted to purchasing bottled water for drinking and cooking. Several customers testified that they have incurred expense to have household filters installed (by non-Aqua NC affiliated vendors) in an effort to improve the quality of water supplied to their homes by Aqua NC. Several of the customers showed the Commission pictures they had taken to demonstrate both discolored water and the effects of the sediment-laden water on their appliances and fixtures. Eleven of 19 customers who testified at the Raleigh hearing receive their water supply from the Bayleaf Master System.

14. Other specific concerns to which customers testified, which are not necessarily water quality related, include the magnitude of the rate increase requested by Aqua NC, the flat-rate sewer methodology rate design, and insufficient notice regarding the public hearing in Wilmington.

15. As of August 21, 2018, the Public Staff had received approximately 57 written customer statements of position, 43 of which complained about water quality issues. In addition, the Commission received approximately 21 written customer statements via electronic mail, primarily expressing opposition to Aqua NC's proposed rate increase and complaining of dissatisfaction with water quality and Aqua NC's customer service. While the number of written statements received in this docket is less than the number of written statements received in the Company's last general rate case filed in 2013, in both dockets, customers continue to communicate complaints that primarily concern poor water quality and Aqua NC's related customer service.

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[1] The Honorable Joe John, member of the North Carolina House of Representatives, although not an Aqua NC customer, appeared at the Raleigh hearing to speak in support of his constituents' concerns. Approximately 55 individuals signed up to testify at the Raleigh hearing, but more than 20 of those yielded their allotted time to testify to three other individual witnesses.

16. The water quality and customer service issues described by the public witnesses, Intervenor Galamb, and customers providing customer statements of position in the present docket are in many instances a repeat of the same types of issues (i.e., discolored water, sediment in the water, damage to appliances and other household property, staining of laundry items and fixtures caused by poor water quality, and shortcomings of the Company's customer service in addressing customer calls and complaints about service and billing) brought to the Commission's attention by customers who provided statements and by witnesses who testified at the public hearings held in the Sub 363 and Sub 319 general rate case dockets.

17. Pursuant to the Commission's directive set forth in its Order Establishing General Rate Case issued in this docket, following each of the four public hearings, the Company filed verified reports with the Commission addressing the concerns raised by customer witnesses at the hearings. The reports described each of the witnesses' specific service-related and water quality concerns and comments, the Company's response, and how each concern and comment was addressed, if applicable. The reports generally explained that naturally-occurring iron and manganese is in the groundwater supply that is the source of water in many of the Aqua NC systems; that the level of iron and manganese in the Company systems meets applicable regulatory standards and poses no health risk to users; that the presence of iron and manganese in the water can cause water discoloration, problems with household appliances, and staining of fixtures and laundry; that the Company has employed various strategies to address the elevated levels of iron and manganese in its water systems (e.g., flushing, chemical sequestration, and installation of various filters); and that the Company works with the Public Staff and the North Carolina Department of Environmental Quality (DEQ) to devise optimal plans to better address the problem of iron and manganese in the Company's water systems.

<u>Quality, Remediation Efforts, and Communications</u>

18. DEQ secondary water quality standards address the acceptable levels of certain constituents, including iron and manganese concentrations, in drinking water. Secondary water quality standards serve as guidelines to operators of water systems on keeping these elements, which are not considered to pose health risks, at levels that consumers will not find objectionable for drinking or consuming due to taste, color, and odor effects. Recently, the United States Environmental Protection Agency (EPA) issued a lifetime health advisory for manganese of 0.3 mg/L and has suggested that exposure to higher levels may impact the health of children.

19. While the DEQ secondary water quality standards serve as guidelines to assist water systems in managing water qualities such as taste, color, and odor, they do not purport to address the suitability or acceptability of water for uses other than drinking, cooking, and human ingestion. The Commission's concern pursuant to N.C.G.S. § 62-43(a) for the quality of water supplied to customers goes beyond state and federal regulatory standards related to human ingestion. Separate and apart from health concerns, the degree or magnitude of water taste, color, and odor problems resulting from elevated levels of iron and manganese, which for purposes of health-related issues are sometimes designated and considered "aesthetic" concerns, can significantly limit or adversely impact customers' ability and willingness to use the water service they pay Aqua NC to provide. Persistent water quality issues related to elevated concentrations of iron and manganese and customer service issues, including slow response to customers'

concerns and the dissemination of inaccurate or incomplete information about flushing and service outages, may render the quality of service for some customers inadequate for non-consumptive purposes, such as cleaning, laundry, waste removal, and use in appliances.

20. Since February 2016 Aqua NC has received 68 Notices of Deficiency (NODs) from the Public Water Supply Section of DEQ. These NODs involved more than 50 water systems and approximately 70 different wells with elevated concentrations of iron and manganese, with most reporting manganese above 0.3 mg/L.

21. The overall quality of water service provided by Aqua NC is adequate on a companywide and systemwide basis for purposes of human consumption and ingestion. The Company meets DEQ's and EPA's health-based primary quality standards. While 26 of Aqua NC's water systems have been noted for deficiencies related to the DEQ secondary water quality standards, the Company is actively working with DEQ and the Public Staff to bring them into compliance. In addition, elements addressed by secondary water quality standards are not considered to pose health risks; EPA's recent health advisory for manganese in excess of 0.3 mg/L did not change this status. The quality of service for non-consumptive uses in some of Aqua NC's individual systems is inadequate due to (1) continued elevated levels of iron and manganese in the water source that make the water provided by Aqua NC to certain of its customers not suitable for generally accepted, non-consumptive household use, and (2) the continued need for improvement in communications with customers on these issues. The overall companywide and systemwide quality of wastewater service provided by Aqua NC is adequate and the Company generally has operated its wastewater plants in a prudent manner.

22. Operational changes and improvements may improve the quality of water in systems affected with elevated levels of iron and manganese. Iron and manganese in groundwater can be remediated through flushing, either at the system level or at customers' residences, through chemical sequestration, and/or through filtration, installed either centrally or at customers' residences.

23. Significantly enabled by the use of the WSIC mechanism, Aqua NC has expended resources and made a commitment towards addressing a number of water quality and other issues that result from the presence of iron and manganese in the source water in its service territory. Aqua NC has made investments in water quality projects to address the presence of iron and manganese totaling approximately $13,000,000 since the Commission issued its order ruling on Aqua NC's last request for general rate increase in Docket No. W-218, Sub 363.

24. After working collaboratively with the Public Staff and DEQ, Aqua NC developed a Water Quality Plan, which it began to implement in 2017. The Company's Water Quality Plan, additionally supported by resources from Aqua America, is an overall plan for addressing iron and manganese water quality issues in its service territory in North Carolina.

25. Flushing is one tool used to maintain and improve water quality in systems affected by iron and manganese. On occasion, as additional means of improving water quality, Aqua NC advises customers to flush their individual premises. When such flushing occurs, Aqua NC's customers are currently billed for the water usage during that flushing event.

26. Aqua NC has deployed in certain of its systems the chemical sequestration product SeaQuest® which is designed to address high concentrations of iron and manganese by dissolving mineral deposits in water pipes. The manufacturer of SeaQuest® recommends flushing systems in which SeaQuest® has been administered at intervals of 30, 60, 90, and 120 days. The Commission noted in its Sub 363 Order ruling on Aqua NC's request for rate increase that the Company had committed to perform the "required" flushing. Since that Order was issued on May 2, 2014, Aqua NC has failed to comply consistently with the manufacturer's recommended flushing schedule when it has administered SeaQuest®, thereby adversely impacting the water quality experienced by customers and likely resulting in increased levels of iron and manganese in the systems where SeaQuest® was deployed without proper flushing.

27. Aqua NC has installed approximately 80 new filters, including 31 greensand filters, as well as filter upgrades and replacements, as part of its efforts to remediate systems experiencing higher concentrations of iron and manganese. Of the Company's remediation options, installation of greensand filters is the most expensive to implement but it is in the Company's opinion the most effective in extracting iron and manganese from the water.

28. To improve communications with its customers, especially as it relates to better communications about water quality issues, Aqua NC has developed a Communications Plan and, in February 2018, implemented what it calls a "Close the Loop" program to assure that an Aqua NC employee contacts every customer who calls with a complaint as a means of follow-up after the customer's call or complaint has been addressed.

Regulatory Oversight and Compliance

29. Pursuant to Ordering Paragraph No. 11 of the Sub 363 Order, Aqua NC and the Public Staff were directed to work together to develop and implement a plan to address the levels of iron and manganese present in water supplied to customers from Aqua NC wells, and to file a report on these secondary water quality issues in June and December of each year the Water System Improvement Charge was in effect (the Semi-Annual Reports Concerning Secondary Water Quality Concerns).[1] These reports were to include the customers affected and the estimated cost of resolving the iron and manganese issues through the WSIC where such issues affected the lesser of 10% of customers in a subdivision service area or 25 billing customers.

30. The method used by Aqua NC to track customer complaints has resulted in some customer complaints regarding iron and manganese concentrations not being quantified for the purpose of fully complying with Ordering Paragraph No. 11 of the Sub 363 Order.

31. Aqua NC and the Public Staff agree that the Company should continue to file the Semi-Annual Reports Concerning Secondary Water Quality Concerns.

[1] Aqua NC requested that the Commission change the reporting schedule to the months of February and August which the Commission allowed by order issued in Docket Nos. W-218, Subs 363 and 363A dated October 31, 2014.

WATER AND SEWER – RATE INCREASE

32. Aqua NC should continue to file its annual Three-Year WSIC and SSIC Plan, as well as its Quarterly Earnings, WSIC/SSIC Revenues, and Construction Status reports. Additional current filings that should continue include Aqua NC's Annual Heater Acquisition Incentive Account Report, the DEQ Quarterly Notice of Deficiency filings, the Secondary Water Quality Filtration Request Executive Summary, the Semi-Annual Reports Concerning Secondary Water Quality Concerns, and the Bi-Monthly Reports on Water Quality Issues pertaining to the issues brought forward by customers in both the Sub 363 docket and the instant Sub 497 docket.

33. In its May 2, 2014 Order ruling on the Company's request for rate increase in the Sub 363 Order, the Commission stated and directed as follows:

> Aqua and the Public Staff should work together to recommend to the Commission appropriate solutions to eradicate to the extent practicable these secondary water quality issues through the use of projects that are eligible for recovery through the WSIC, if appropriate. Further, in order for the Public Staff to interact effectively with DE[Q] concerning any continuing water quality issues at Aqua systems and to be in a more informed position to work with Aqua to formulate a recommendation to the Commission regarding the need and appropriateness of more extensive improvements to address secondary water quality issues, the Commission finds and concludes that Aqua should convey *conversations with, reports to, and the recommendations of DE[Q]to the Public Staff* regarding the water quality concerns being evaluated and addressed in Aqua's systems *in a timely manner as requested by the Public Staff.*. Such communication [to the Public Staff] should be in a written format and *should be provided, at a minimum, on a bi-monthly basis.* Aqua should provide the Public Staff copies of: (a) Aqua's reports and letters to DE[Q] concerning water quality concerns in its systems; (b) responses from DE[Q] concerning reports, letters, or other verbal or written communication received from Aqua; and (c) DE[Q]'s specific recommendations to Aqua, by system, concerning each of the water quality concerns being evaluated by DE[Q]. [Emphasis added.]

34. Aqua NC and the Public Staff should continue to work together regarding the development of appropriate recommendations and solutions to improve water quality at Aqua NC's affected systems. Aqua NC should continue to report on its conversations with DEQ as the Commission previously directed in the Sub 363 Order. "Report" in this context means notification of the fact of meetings or conversations and the salient topics and points discussed in such meetings or conversations. In addition to written communications described in the Sub 363 Order as noted above, Aqua NC should take steps to ensure that the Public Staff is copied on all written communications with DEQ that relate to compliance with or deficiencies in compliance with the secondary water quality standards enforced by DEQ. Aqua NC and the Public Staff should work together to resolve any dispute that may arise between them regarding the sharing of communications with DEQ about water quality at Aqua NC's affected systems, and should not

wait until the next general rate case to notify the Commission of unresolved complaints related to DEQ communications to be shared with the Public Staff pursuant to Commission order.

Rate Base

35. The appropriate level of rate base used and useful in providing service is $190,472,859 for Aqua NC's combined operations, itemized as follows:

Item	Amount
Plant in Service	$492,295,394
Accumulated depreciation	(155,246,692)
Contributions in aid of construction (CIAC)	(196,384,493)
Accumulated amortization of CIAC	70,758,708
Acquisition adjustments	2,055,735
Accumulated amortization of acquisition adjustments	1,040,444
Advances for construction	(4,467,841)
Net plant in service	210,051,255
Customer deposits	(379,445)
Unclaimed refunds	(193,255)
Accumulated deferred income taxes	(24,849,085)
Materials and supplies inventory	2,405,967
Excess capacity adjustment	(1,322,276)
Working capital allowance	4,759,698
Original cost rate base	$190,472,859

36. It is appropriate to make the following adjustments (including applicable accumulated depreciation) of $6,655,081 to Plant in Service for Aqua NC's combined operations:

Item	Amount
Adjustment for post-test year additions	$8,769,089
Adjustment for costs related to future customers	5,992
Adjustment to remove Johnston County capacity payment	(2,120,000)
Adjustment to meters and meter installations	0
Total adjustment to Plant in Service	$6,655,081

37. By the 2014 Rate Case Order, the Commission allowed Aqua NC to include the costs related to the Company's Automated Meter Reading (AMR) aged meter replacement program in rates paid by Aqua NC's customers in the Brookwood Water Operations Rate Division. However, as part of settlement in that case, Aqua NC and the Public Staff entered into a Stipulation dated January 17, 2014, which provided, at Paragraph 15, that:

> **Automated Meter Reading – Radio Frequency.** Aqua and the Public Staff disagree about the reasonableness, prudency, and cost-effectiveness of installation of Automated Meter Reading – Radio Frequency (AMR-RF) water meters. The Stipulating Parties agree

> that although the Public Staff did not recommend an adjustment to Aqua's current investment for the installation of AMR-RF meters in this proceeding, the Public Staff has the right as a matter of law to challenge the reasonableness, prudency, and cost-effectiveness of Aqua's investment in AMR-RF meters in future cases.

The Commission approved and incorporated Stipulation Paragraph 15 as Finding of Fact No. 54 of the 2014 Rate Case Order.

38. It is inappropriate to reduce the original cost meter and meter installation rate base for the meter replacement projects of the Aqua NC Water Operations and Brookwood Water Operations rate divisions, as recommended by the Public Staff.

39. It is appropriate to include Aqua NC's investment in AMR technology in rates in this proceeding. Aqua NC's decisions to implement AMR technology in conjunction with the Company's aged meter replacement program, and to utilize contractor-provided labor for such projects were reasonable and prudent. The functionalities of AMR technology installed by Aqua NC are currently being utilized to the benefit of the ratepayers and will incrementally increase benefits to customers in the long-term as the AMR technology is fully deployed.

40. It is appropriate and prudent for Aqua NC to continue implementing its aged meter replacement program, utilizing contractor-provided labor as managed by the Company, whereby standard water meters that have reached the end of their useful lives will be replaced by AMR technology, as appropriate.

41. Aqua NC provides both water and wastewater treatment services to the Flowers Plantation development, which consists of a large number of acres generally divided between the eastern half (Buffalo Creek) and the western half (Neuse Colony), located along the Neuse River and Highway 42 in Johnston County, North Carolina. Neuse Colony originally was provided wastewater utility service by a 50,000-gallon per day (gpd) wastewater treatment plant (Neuse Colony WWTP) owned and operated by River Dell Utilities, Inc.[1] In 2003, Heater Utilities, Inc. (Heater) completed construction of a 250,000-gpd expansion of the Neuse Colony WWTP, and in 2016, Aqua NC expanded the capacity by an additional 100,000 gpd. It is reasonable and appropriate to include in rate base the full amount of $908,497, representing actual costs incurred by Aqua NC to build the 100,000-gpd Neuse Colony WWTP expansion in 2016.

42. The current total capacity at the Neuse Colony WWTP is 350,000 gpd, reflecting both the 2003 and 2016 system expansion upgrades. When originally permitted, the Neuse Colony

[1] River Dell Utilities, Inc. was subsequently transferred to Heater Utilities, Inc. (Heater). Heater was acquired by Aqua through a transfer of stock on June 1, 2004. The Commission takes judicial notice of its Order of May 26, 2004, in Docket No. W-274, Sub 465, whereby the Commission approved the transfer to Aqua of all Heater common stock. Aqua, by acquiring all of Heater's common stock, assumed all of Heater's contractual rights and obligations.

WWTP was rated by the North Carolina Department of Environmental Quality (DEQ)[1] at 360-gpd per residential customer. Aqua NC subsequently applied to DEQ for, and was granted, flow reductions that reduced the rating from 360 gpd to 240-gpd per residential customer following the 2003 system expansion, and then again from 240 gpd to the current rating of 180-gpd per residential customer following the 2016 system expansion. Based on the amount of actual capacity remaining at the Neuse Colony WWTP after applying the flow reduction rates authorized by DEQ, Aqua NC is utilizing approximately 316,000 gpd of its total 350,000 gpd of capacity. The Company collected contributions in aid of construction (CIAC) in the amount of $2,294,168, exceeding the related original plant cost of $2,166,023. Because there remains additional capacity to be utilized, the Company may continue to make such capacity available to developers, and, consequently, to collect additional CIAC from developers.

43. Aqua NC failed to collect CIAC to which it was contractually entitled for the 50% balance of its costs to construct the Buffalo Creek Pump Station and Force Main. Of the $315,687 in uncollected CIAC, Aqua NC failed to collect $218,999 subsequent to the updated cutoff of October 31, 2013, in Aqua NC's last rate case.[2] Therefore, it is appropriate to impute $218,999 in uncollected CIAC for the Buffalo Creek Pump Station and Force Main to offset Aqua NC's existing rate base.

44. In June 2018, Aqua NC reserved 250,000 gpd of wastewater treatment capacity from Johnston County, North Carolina (the County), by payment of $1,335,000, or $5.34 per gpd of capacity, for the purpose of allowing development of lots in Flowers Plantation. Aqua NC paid the County $785,000 as payment of a transmission/distribution fee. Although the Company was prudent in its decision to reserve from the County 250,000 gpd of wastewater treatment capacity in June 2018, the capacity reserved could not have been available to Aqua NC as of the end of the test year because the interconnection between the County's system and Aqua NC's has not yet been completed. Likewise, the interconnection will not be completed and placed in service within a reasonable time following the end of the test year. Therefore, it is reasonable and appropriate that the $1,335,000 of reserved capacity be removed from Plant in Service, and, thus, excluded from rate base, and that the $785,000 paid as a transmission and distribution expense be recognized as an operating revenue deduction to be amortized over six years with no unamortized balance in rate base.

45. It is appropriate to make excess capacity adjustments to Aqua NC's Sewer Operations' utility Plant in Service applicable to Aqua NC's wastewater treatment plants (WWTPs) located at Carolina Meadows, The Legacy at Jordan Lake, and Westfall (a/k/a Booth Mountain). The appropriate percentages for these WWTP excess capacity adjustments are 30.63% for the Carolina Meadows WWTP; 38.67% for The Legacy at Jordan Lake WWTP; and 35.56% for the Westfall WWTP.

46. It is appropriate to apply the excess capacity adjustment of 30.63% for Carolina Meadows WWTP to 50% of the Company's post-test year, major modification and rehabilitation

[1] Formerly known as the North Carolina Department of Environment and Natural Resources (DENR). DENR's name changed to DEQ effective September 18, 2015.

[2] Docket No. W-218, Sub 363.

upgrade project at that facility, the cost of which was approximately $1.7 million. It is appropriate to include the remaining 50% of the major modification and rehabilitation upgrade projects at the Carolina Meadows WWTP in rate base as a post-test year addition.

47. It is appropriate to include, as a part of the excess capacity adjustments in this case, the capital costs for improvements in the total amount of approximately $175,000 incurred at the Company's WWTPs prior to or during the test year.

48. It is appropriate to reduce Aqua NC Sewer Operations' rate base by $1,322,276, to remove WWTP excess capacity.

49. It is unreasonable to allow Aqua NC to utilize deferred accounting with respect to WWTP amounts determined to be excess capacity, and consequently removed from rate base, for the WWTPs serving Carolina Meadows, The Legacy at Jordan Lake, and Westfall. Aqua NC's requested accounting treatment to allow it to defer the recovery of depreciation and to capitalize carrying costs until the capacity is actually utilized is denied.

50. An adjustment to update accumulated deferred income taxes (ADIT) to include the deferred tax related to the unamortized balance of rate case expense should be made in this proceeding.

51. ADIT should be adjusted to include the deferred taxes related to post-test year plant additions.

52. It is appropriate to adjust ADIT to reflect the deferred taxes related to the unamortized repair tax credit balance.

Revenues

53. By its Application, for the test period ending September 30, 2017, Aqua NC requested a total annual revenue increase of $4,935,516, an 8.97% increase over the total revenue level generated by the rates and miscellaneous charges currently in effect for the Company, consisting of the following amounts for water and sewer operations:[1]

Item	Amount
Aqua NC Water Operations	$2,773,109
Aqua NC Sewer Operations	$628,764
Aqua NC Sewer Operations	$ 90,748
Fairways Sewer Operations	$ 671,750
Brookwood Water Operations	$ 771,145

[1] By its Application, Aqua NC requested an increase in total annual service revenues of $4,968,935, a 9.19% increase over the total annual service revenues generated by the rates currently in effect for the Company.

54. It is appropriate to make adjustments of $11,520 for Aqua NC Water Operations and $60,720 for Aqua NC Sewer Operations to reclassify availability revenues from service revenue to miscellaneous revenue, as stipulated.

55. It is appropriate to adjust late payment fees and uncollectibles based on the percentages provided by the Company in the Application.

56. For the updated test period ending June 30, 2018, the appropriate level of combined operating revenues under present rates for use in this proceeding is $56,553,038, consisting of service revenues of $55,496,957, late payment fees of $114,830, and miscellaneous revenues of $1,355,499, reduced by uncollectibles and abatements of $414,248. Aqua NC's combined operations present service revenues amount of $55,496,957 is composed of the following water and sewer service revenues:

Item	Amount
Aqua NC Water Operations	$34,566,184
Aqua NC Sewer Operations	$13,459,559
Fairways Water Operations	$ 1,084,684
Fairways Sewer Operations	$ 1,360,925
Brookwood Water Operations	$ 5,025,605

57. For the updated test period ending June 30, 2018, the appropriate level of combined operating revenues under Aqua NC's proposed rates for use in this proceeding is $61,184,627, consisting of service revenues of $60,154,323, late payment fees of $124,429, and miscellaneous revenues of $1,355,499, reduced by uncollectibles and abatements of $449,624.

58. Aqua NC and the Public Staff have agreed to the customer counts, consumption quantities, and the pro forma revenues under present rates and Aqua NC's proposed rates for the updated test period ending June 30, 2018.

<u>Operating and Maintenance (O&M) and
General and Administrative (G&A) Expenses</u>

59. It is appropriate to update salaries and wages through June 30, 2018, as stipulated.

60. Aqua NC has historically experienced some turnover in employees, and therefore, will always have some level of open positions on an ongoing basis. It is appropriate to remove five open positions from the update amount of salaries and wages, as stipulated.

61. Aqua NC has contracted with United States Infrastructure Corporation (USIC) to perform One Call/NC 811 work which is essential to the safety of interested parties and to the longevity and condition of Aqua NC's infrastructure. Such work was previously partially completed by Company personnel.

62. The Public Staff's proposed adjustment to exclude 50% of the updated labor costs (salaries and benefits totaling $73,799) of four Aqua NC field operational employees from the cost of service in this case is inappropriate.

63. Overtime pay should be adjusted to reflect each individual employee's updated payroll as of June 30, 2018, as stipulated.

64. The Public Staff's proposed accounting adjustment to allocate 30% of North Carolina supervisory employee bonuses in the amount of $29,648 to shareholders and thereby exclude those expenses from the cost of service in this case is inappropriate.

65. It is not appropriate to adopt the Public Staff's recommended adjustment to allocate to shareholders 50% of the compensation, including pension and incentive plans, of the top five Aqua America executives totaling $213,756 in compensation and $80,845 in pensions and incentive plans.

66. It is appropriate to allocate to shareholders 25% of the compensation, including pension and incentive plans, of the top five Aqua America executives totaling $106,878 in compensation and $40,423 in pensions and incentive plans, thereby removing 25% of these expenses from Aqua NC's cost of service.

67. It is appropriate to update pensions and benefits through June 30, 2018, as stipulated.

68. Employee pensions and benefits related to five open positions should be deducted from operating expenses, as stipulated.

69. It is appropriate to remove the Company's estimated pro forma adjustment to pensions and benefits and use the actual amounts as of June 30, 2018, as stipulated.

70. Aqua NC's update to pensions and benefits included the cost related to Health Advocate twice in operating expenses. The duplicate Health Advocate expenses should be deducted from updated pensions and benefits, as stipulated.

71. It is appropriate to increase sludge hauling expense by $23,049.

72. It is appropriate to include in O&M expenses annual testing expense of $926,947, consisting of $882,746 for compliance testing and $44,201 for operational testing, prior to considering the update for Notice of Deficiency (NOD) site testing expense.

73. It is appropriate to reduce post-test year testing expense by $92,112, resulting in an increase to test year testing expense for NOD site testing of $19,426 which results from the amortization of such total testing expenses of $58,278 over three years.

74. The appropriate level of annual testing expense for use in this proceeding is $946,373, including NOD site testing expense.

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75. On August 21, 2018, the Public Staff filed schedules which included an adjustment to decrease the Company's filed purchased water expense of $1,947,892 by $73,670. During discovery, the Company reduced its filed purchased water expense to $1,941,621.

76. Nine of Aqua NC's third-party purchased water accounts exceeded 15% water loss, with such losses ranging from 19% to 74% for the test year. The Public Staff recommended a reduction in purchased water expense for the Aqua NC systems that had greater than 15% water loss during the test year.

77. For purposes of this proceeding, it is appropriate to include an amount of recoverable water loss of 15% for a purchased water system.

78. The appropriate level of annual purchased water expense is $1,874,173.

79. It is appropriate for Aqua NC to recover total rate case expenses of $818,397, related to the current proceeding to be amortized over a four-year period, except the Company's 2017 depreciation study which should be amortized over five years, for an annual level of rate case expense of $201,666.

80. The Aqua Communications Initiative is not a ratemaking expense. This Communications Initiative is a reasonable operating expense and includes startup costs for a completed customer survey and a completed water quality website. As part of the costs are nonrecurring, it is appropriate to amortize one-half of the $83,940 costs (or $41,970) over three years, resulting in an annual expense of $13,990, as stipulated.

81. It is not appropriate to adopt the Public Staff's recommended adjustment to allocate to shareholders 50% of the compensation and expenses of the Aqua America Board of Directors totaling $58,419 in compensation and $8,691 in expenses.

82. It is appropriate to remove 25% of the Aqua America Board of Directors fees totaling $29,210 in compensation and $4,345 in expenses in this proceeding.

83. The Public Staff's proposed consumption adjustment factors should not be applied to either Aqua NC's Sewer Operations rate division or the Company's Fairways Sewer Operations rate division. The consumption adjustment factors proposed by the Public Staff should only be applied to Aqua NC's three water rate divisions (Aqua NC Water Operations, Brookwood Water Operations, and Fairways Water Operations).

84. It is appropriate to include sludge hauling expense in the calculation of the Company's annualization adjustment in this proceeding.

85. It is appropriate to exclude materials and supplies expense from the calculation of the Company's annualization adjustment in this proceeding.

86. The appropriate level of operating, maintenance, and general expenses is $31,267,804 for the combined operations.

WATER AND SEWER – RATE INCREASE

Depreciation and Amortization Expense

87. It is appropriate to make an adjustment to increase depreciation expense by $8,518 to reflect that 50% of the post-test year updates to the Carolina Meadows WWTP are included as a post-test year addition not subject to the excess capacity disallowance. A total increase to depreciation expense of $28,890 and amortization expense of $23,667 for the Carolina Meadows, The Legacy at Jordan Lake, and Westfall WWTPs is appropriate in this proceeding.

88. It is inappropriate to remove $139,727 of depreciation expense related to meters and meter installations in this proceeding as recommended by the Public Staff.

89. It is inappropriate to remove $42,676 of amortization expense in this proceeding related to the $1.497 million in CIAC collected from developers pursuant to contracts for the purchase of additional wastewater treatment capacity for the Neuse Colony WWTP.

90. An adjustment of $6,241 to amortization expense related to the imputation of CIAC in the amount of $218,999, for the Buffalo Creek force main and pump station costs that Aqua NC did not collect from developers should be made in this proceeding.

91. The appropriate level of depreciation and amortization expense for combined operations to be used in this proceeding is $10,076,409.

Other Taxes and Section 338(h) Adjustment

92. Payroll taxes should be calculated on the adjusted level of salaries and wages and the current payroll tax rates.

93. It is appropriate to remove 25% of payroll taxes to match the adjustment the Commission has made to salaries and wages related to executive compensation.

94. The appropriate level of payroll taxes for use in this proceeding is $789,484 for combined operations.

95. The appropriate level of other taxes and Section 338(h) adjustment for use in this proceeding is $1,713,809 for combined operations, consisting of $635,463 for property taxes, $789,484 for payroll taxes, $308,886 for other taxes, and a reduction of $20,024 for the Section 338(h) adjustment.

Regulatory Fee and Income Taxes

96. It is appropriate to use the current statutory regulatory fee rate of 0.14% to calculate Aqua NC's revenue requirement. The appropriate level of regulatory fee expense for use in this proceeding is $79,174.

97. The appropriate level of state income taxes for use in this proceeding is $272,043, which is based on the current state corporate income tax rate of 3%.

98. It is reasonable and appropriate to calculate federal income taxes using the current federal corporate income tax rate of 21%.

99. The appropriate level of federal income taxes for use in this proceeding is $1,847,171.

The Federal Tax Cuts and Jobs Act

100. Aqua NC and the Public Staff reached agreement regarding the appropriate ratemaking treatment in this proceeding to reflect the provisions of the Federal Tax Cuts and Jobs Act (the Tax Act) as outlined in Section III, Paragraphs II, JJ, and KK of the Stipulation filed on September 17, 2018, by Aqua NC and the Public Staff. The agreements regarding the applicable provisions of the Tax Act reached jointly by the Company and the Public Staff are appropriate.

101. The Company's revenue requirement shall reflect the reduction in the federal corporate income tax rate from 35% to 21%, on the Company's ongoing federal income tax expense.

102. The Company's protected federal excess deferred income taxes (EDIT) should be flowed back to customers by amortizing the protected EDIT over a period of time equal to the expected lifespan of the plant, property, and equipment with which they are associated, in accordance with the normalization rules of the United States Internal Revenue Service (IRS).

103. The Company's unprotected federal EDIT should be returned to ratepayers through a levelized rider over a period of three years.

104. The Company's proposal to refund to its ratepayers the overcollection of federal income taxes related to the decrease in the federal corporate income tax rate for the period beginning January 1, 2018, and corresponding interest, through a surcharge credit for a one-year period beginning when the new base rates become effective in the current docket is reasonable and appropriate. The Company's state EDIT recorded pursuant to the Commission's Order Addressing the Impacts of HB 998 on North Carolina Public Utilities issued May 13, 2014, in Docket No. M-100, Sub 138 should be returned to ratepayers through a levelized rider that will expire at the end of a three-year period.

Rate of Return on Equity, Capital Structure, and Cost of Debt

105. The cost of capital and revenue increase approved in this Order is intended to provide Aqua NC, through sound management, the opportunity to earn an overall rate of return of 7.17%. This overall rate of return is derived from applying an embedded cost of debt of 4.63%, and a rate of return on equity of 9.70%, to a capital structure consisting of 50% long-term debt and 50% equity.

106. A 9.70% rate of return on equity for Aqua NC is just and reasonable in this general rate case.

WATER AND SEWER – RATE INCREASE

107. A 50% equity and 50% long-term debt ratio is a reasonable capital structure for Aqua NC in this case.

108. A 4.63% cost of debt for Aqua NC is reasonable for the purpose of this case.

109. The rate increase approved in this case, which includes the approved rate of return on equity and capital structure, will be difficult for some of Aqua NC's customers to pay, particularly Aqua NC's low-income customers.

110. Continuous safe, adequate, and reliable water and wastewater utility service by Aqua NC is essential to Aqua NC's customers.

111. The rate of return on equity and capital structure approved by the Commission appropriately balances the benefits received by Aqua NC's customers from Aqua NC's provision of safe, adequate, and reliable water and wastewater utility service with the difficulties that some of Aqua NC's customers will experience in paying the Company's increased rates.

112. The 9.70% rate of return on equity and the 50% equity capital structure approved by the Commission in this case will result in a cost of capital that is as low as reasonably possible. They appropriately balance Aqua NC's need to obtain equity and debt financing with the ratepayers' need to pay the lowest possible rates.

113. The authorized levels of overall rate of return and rate of return on equity set forth above are supported by competent, material, and substantial record evidence, are consistent with the requirements of N.C.G.S. § 62-133, and are fair to Aqua NC's customers generally and in light of the impact of changing economic conditions.

Revenue Requirement

114. It is reasonable and appropriate to determine the revenue requirement for Aqua NC using the rate base method as allowed by N.C.G.S. § 62-133.

115. Aqua NC's total annual operating revenues should be changed by amounts which, after pro forma adjustments, will produce the following increases (decreases) in total operating revenues:

Item	Amount
Aqua NC Water	$776,379
Aqua NC Sewer	868,496
Fairways Water	(7,441)
Fairways Sewer	720,953
Brookwood Water	537,633
Total Aqua NC	$2,896,020

These increases (decreases) will allow Aqua NC the opportunity to earn a 7.17% overall rate of return, which the Commission has found to be reasonable upon consideration of the findings in this Order.

Rate Design

116. It is appropriate to design rates in the ratio and structure as reflected in Junis Late-Filed Exhibit 11.

117. The rates and charges included in Appendices A-1, A-2, A-3, and A-4, attached hereto, are just and reasonable and should be approved.

Consumption Adjustment Mechanism

118. In its Application, Aqua NC requests Commission approval of a rate adjustment mechanism to account for variability in average monthly consumption per customer, which directly affects revenues.

119. Aqua NC failed to demonstrate that its proposed consumption adjustment mechanism is reasonable or justified.

Water and Sewer System Improvement Charges

120. Consistent with Commission Rules R7-39(k) and R10-36(k), Aqua NC WSIC and SSIC surcharges will reset to zero as of the effective date of the approved rates in this proceeding.

121. By law, the cumulative maximum charges that the Company can recover through system improvement charges between rate cases cannot exceed 5% of the total service revenues approved by the Commission in this rate case.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-4

The evidence supporting these findings of fact and conclusions is contained in the Company's Application and NCUC Form W-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding. These findings and conclusions are informational, procedural, and jurisdictional in nature and are not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-10

The evidence supporting these findings of fact is contained in the Stipulation and in the testimony of Aqua NC and Public Staff witnesses. On September 17, 2018, Aqua NC and the Public Staff entered into and filed the Stipulation, which resolved some of the issues in this proceeding between these two parties and provided for a revenue requirement increase of approximately $1,268,414 for combined operations based on the settled issues. The Stipulation is based upon the same test period as Aqua NC's Application, adjusted for certain changes in plant, revenues, and costs that were not known at the time the case was filed but occurred or became known through June 30, 2018.

The key aspects of the Stipulation are provided as follows:

Capital Structure

The Stipulating Parties agree that the capital structure appropriate for use in this proceeding is a capital structure consisting of 50.00% common equity and 50.00% long-term debt at a cost of 4.63%.

Salaries and Wages

The Company accepts the Public Staff's proposed adjustment to update salaries and wages through June 30, 2018. The Stipulating Parties agree to a revenue requirement impact adjustment in the amount of ($174,680) for combined operations to remove five open positions as set forth in the supplemental testimony of Public Staff witness Henry. The Company also accepts the Public Staff's proposed adjustment to overtime pay as set forth in the supplemental testimony of Public Staff witness Henry.

Pensions and Benefits

The Company accepts the Public Staff's proposed adjustment to update pensions and benefits through June 30, 2018. The Stipulating Parties agree to a revenue requirement impact adjustment of ($150,196) for combined operations to remove benefits related to the five open positions. The Company also accepts the Public Staff's proposed adjustment to remove duplicative Health Advocate costs.

Plant in Service

The Public Staff agrees to withdraw its proposed adjustment related to Neuse Colony rate base as reflected on Line 7 of Settlement Exhibit 1. The Company accepts the Public Staff's proposed adjustment to plant related to future customers as set forth in the supplemental testimony of Public Staff witness Cooper. The Company also accepts the Public Staff's proposed adjustment to re-allocate vehicles as set forth in the supplemental testimony of Public Staff witness Cooper.

Salaries and Wages

The Company accepts the Public Staff's proposed adjustment that reflected the adjusted level of salary wages and current payroll taxes.

Insurance Expenses

The Company accepts the Public Staff's proposed adjustment to update insurance expenses as set forth in the supplemental testimony of Public Staff witness Cooper.

Miscellaneous Expense

The Stipulating Parties agree to a revenue requirement impact adjustment of $14,009 for combined operations to allow partial recovery of the Company's costs associated with its communication initiative.

Updated Service Revenues

The Company accepts the Public Staff's proposed adjustment to updated service revenues from customer growth as set forth in the supplemental testimony of Public Staff witness Junis.

Reclassification of Revenues

The Company accepts the Public Staff's proposed adjustment to reclassify availability fees from service revenues to miscellaneous revenues.

Advances for Construction

The Company accepts the Public Staff's proposed adjustment to advances for construction.

Contract Services – Legal

The Company accepts the Public Staff's proposed adjustments to remove pre-test year legal invoices and to remove legal fees related to fines and penalties. The Company also agrees to the Public Staff's proposed adjustment removing legal fees related to legislation.

Accumulated Deferred Income Taxes (ADIT) and Excess Deferred Income Taxes (EDIT)

The Company agrees to the Public Staff's proposed adjustments to ADIT regarding unamortized rate case expense, unamortized repair tax credit, post-test year plant additions, and EDIT.

The Stipulating Parties agree to revise ADIT for any updates made to regulatory commission expenses. The Company agrees to accept the Public Staff's proposals for addressing the Tax Act. The unprotected Federal EDIT created by enactment of the Tax Act will be returned to customers through a levelized rider that will expire at the end of a three-year period. The protected EDIT will be flowed back following the tax normalization rules utilizing the average rate assumption method (ARAM) required by IRC Section 203(e). The Stipulating Parties agree that the State EDIT that Aqua NC recorded pursuant to the Docket No. M-100, Sub 138 Order will be returned to customers through a levelized rider that will expire at the end of a three-year period.

The Stipulating Parties agree to the Company's proposal to refund to the ratepayers the overcollection of federal taxes related to the decrease in federal tax rates for the period beginning January 1, 2018, and corresponding interest, as a surcharge credit for a one-year period beginning when the new base rates become effective in the current docket.

WATER AND SEWER – RATE INCREASE

Acquisition Incentive Adjustments (AIA)

Aqua NC accepts the Public Staff's proposed adjustment to AIA as set forth in the supplemental testimony of Public Staff witness Cooper.

Purchase Acquisition Adjustment (PAA)

The Company accepts the Public Staff's proposed adjustment to Mid-South growth PAA as set forth in the supplemental testimony of Public Staff witness Cooper.

Working Capital Allowance

The Stipulating Parties agree to a revenue requirement impact adjustment of ($15,972) for combined operations for working capital.

Service Revenues

Aqua NC accepts the Public Staff's proposed adjustment to late payment fees as set forth in the supplemental testimony of Public Staff witness Cooper.

Uncollectibles and Abatements

Aqua NC accepts the Public Staff's proposed adjustment to uncollectibles and abatements as set forth in the supplemental testimony of Public Staff witness Cooper.

Transportation Expense

The Company accepts the Public Staff's proposed adjustment to transportation fuel expense as set forth in the supplemental testimony of Public Staff witness Cooper.

Purchased Power Expense

Aqua NC agrees to the Public Staff's proposed adjustment to purchased power expense as set forth in the testimony of Public Staff witness Darden.

Chemical Expense

The Company agrees to the Public Staff's proposed adjustment to chemical expense as set forth in the testimony of Public Staff witness Darden.

Contract Services – Other

Aqua NC agrees to the Public Staff's proposed adjustment to remove pre-test year invoices from contract services. Aqua NC also agrees to the Public Staff's proposed adjustment to contract services related to NC 811 locates.

Regulatory Commission Expense

The Stipulating Parties agree to a methodology for calculating regulatory commission expense, also known as rate case expense, and agree to update the number in Settlement Exhibit 1, Line 33 for actual and estimated costs once supporting documentation is provided by the Company. However, Aqua NC seeks a three-year amortization period; the Public Staff supports a five-year period.

Payroll Taxes

The Stipulating Parties agree to a revenue requirement impact adjustment of $8,271 for payroll taxes as set forth in the supplemental testimony of Public Staff witness Henry.[1]

No party filed a formal statement or testimony indicating opposition to the Stipulation; however, the AGO did pursue cross-examination of Aqua NC and Public Staff witnesses at the hearing of this matter on contested, nonstipulated issues related to matters such as rate of return and quality of service issues. Pro se Intervenor Galamb participated only to present testimony. The Stipulation is binding as between Aqua NC and the Public Staff, and conditionally resolved certain specific matters in this case as between those two parties. Through the end of the evidentiary process, the AGO and Intervenor Galamb neither approved nor expressly disapproved of the partial settlement regarding the specific settled issues reflected in the terms of the Stipulation, except that Intervenor Galamb generally opposed any rate increase. There are no other parties to this proceeding.

As the Stipulation has not been adopted by all of the parties to this docket, its acceptance by the Commission is governed by the standards set out by North Carolina law. A stipulation entered into by less than all parties in a contested case proceeding under Chapter 62 "should be accorded full consideration and weighted by the Commission with all other evidence presented by any of the parties in the proceeding." State ex rel. Utilities Commission v. Carolina Utility Customers Association, Inc., 348 N.C. 452, 466, 500 S.E. 2d 690, 700 (1998). Further, "[t]he 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." Id.

The Commission concludes, based upon all the evidence presented, that the Stipulation was entered into by the Stipulating Parties after full discovery and extensive negotiations and represents a reasonable and appropriate proposed negotiated resolution of certain specific matters in dispute in this proceeding and that neither the AGO nor Intervenor Galamb expressly objected to the settlement but Intervenor Galamb did not change his general position opposing any rate increase.

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[1] The Commission observes that the revenue requirement impact of $8,271 for payroll taxes adjustment agreed to by the stipulating parties includes a reduction in the amount of $2,841 related to the Public Staff's adjustment to allocate 50% of executive compensation to shareholders, which was disputed by Aqua NC. As discussed elsewhere in this Order, the Commission has adjusted payroll taxes to reflect its adjustment to remove 25% of executive compensation.

WATER AND SEWER – RATE INCREASE

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11-34

The evidence supporting these findings of fact is contained in the testimony and exhibits of Aqua NC witnesses Becker and Crockett, Public Staff witness Junis, Intervenor Galamb, the public witnesses, the verified reports filed by Aqua NC in response to the concerns testified to by the public witnesses, the determinations in the Sub 363 Order concerning quality of service, and the record in this proceeding.

Customer Concerns – Service and Water Quality-Related Issues

Public hearings were held in Mocksville, Gastonia, Raleigh, and Wilmington for the purpose of receiving the testimony of non-expert, public witnesses. No public witnesses appeared at the Mocksville public hearing. Customer witnesses testifying at the hearing in Wilmington primarily expressed their opposition to the Company's requested rate increase. Two public witnesses testified at the Gastonia hearing, one of whom testified regarding her inability to use discolored water at her residence. Of the 20 witnesses who testified at the Raleigh hearing, 19 testified that the poor quality of the water supplied by Aqua NC caused serious problems, including discoloration of laundry and fixtures, damage to appliances, inability and/or difficulty to use for drinking, cooking, bathing, and cleaning and did not justify the price they were paying for water service, much less an increase in Aqua NC's rates. The customers' testimony demonstrated how the poor water quality they experience at their homes causes them stress, disrupts their daily lives, and causes them to incur significant expense to repair and replace damaged and stained clothing, appliances, and plumbing fixtures and to purchase bottled water for drinking and cooking. The concerns voiced by these witnesses, as confirmed by the Company's filed Response to Customer Concerns, relate to the high concentrations of iron and manganese in their water. The water quality concerns (such as inability to drink and damage to appliances and plumbing fixtures) of the customer witnesses appearing before the Commission in this docket were essentially identical to the types of complaints of customer witnesses who testified at the public hearings held in the Subs 319 and 363 dockets in 2011 and 2013 respectively.

In addition to the effects of high concentrations of iron and manganese on their personal property, some witnesses appearing to testify in this docket expressed concerns about the potential effects of these elements on their health and the health of their families. Several witnesses testified that they had installed water filtration systems in their homes at significant cost as a result of the poor water quality supplied to their homes by the Company. Tr. Vol. 12, pp. 104-109.

Many of the witnesses, who testified about issues related to poor water quality, also testified about issues with Aqua NC's customer service. They testified about the lack of responsiveness to customer communications, inaccurate notifications to customers regarding flushing activities and other service interruptions, and concerns that customers' complaints were not being accurately recorded by the Company. Id.

Becky Daniel, a resident of Coachman's Trail subdivision served by Aqua NC's Bayleaf Master System, testified at the Raleigh public hearing. Approximately eight other customers who attended the hearing yielded their allotted time to her. Witness Daniel's testimony was typical of the testimony given by other witnesses at the Raleigh public hearing. Her testimony touched on both water quality and customer service issues she has experienced as a customer of Aqua NC. With respect to water quality, witness Daniel testified that she has experienced numerous instances of discolored water throughout the 12 years she has lived in her home, but that the instances have occurred more frequently since 2017. Tr. Vol. 3, p. 29. Witness Daniel testified that, during the second half of 2017, she flushed water for approximately 200 minutes from her home's outdoor spigots to address discolored water. She complained that she did not receive a bill credit from the Company after the flushing event. Id. at 29-30.

Witness Daniel testified further about issues with Aqua NC's customer service, including her concern that automatic messages informing callers that the Company was already aware of service issues in their areas were sometimes misleading and discouraged customers from completing their calls, and her concern that Aqua NC is not accurately recording the number of customer calls. Witness Daniel also testified about inaccurate communications from Aqua NC concerning service interruptions. Specifically, she testified that she had once received a telephone message from the Company notifying her about a service outage which she later learned did not apply to her neighborhood and that she had also received a telephone message notifying her that the Company would be flushing but the call came the day after the flushing had already commenced. Id. at 30-32.

Several of the concerns raised by witness Daniel in her testimony were similar to those raised by Intervenor Galamb, who stated that Aqua NC needs to improve on its communications with its customers. He offered his opinion that despite having two call centers, Aqua NC had done a poor job communicating with its customers. Based on his first-hand experiences with Aqua NC's customer service personnel, he asserted that no rate increase should be passed on to the customers. Further, in his opinion, the Company's poor customer service does not support a rate increase for the Company.

The Company addressed, in writing, all of the concerns raised by the witnesses at the four hearings. In its Responses to Customer Concerns filed following the public hearings, Aqua NC generally reported that it spoke to some customers immediately at the conclusion of the public hearings and/or later, in the days following the hearings, met with, called or otherwise attempted to contact the witnesses who testified at the hearings to discuss their concerns, address them and provide helpful explanations and answers regarding issues they raised. Regarding water quality, Aqua NC used the opportunity to relay that since beginning to serve North Carolina customers in 2000, it has spent a lot of time, effort, and resources trying to improve secondary water quality issues involving the presence of iron and manganese in the water supply used to serve its customers. Aqua NC explained that over the years and through the current time it has implemented iron and manganese removal techniques, such as flushing, oxidation, sedimentation and filtration, including the installation of expensive greensand filters. In the last five years, Aqua NC stated that it has installed 80 filters in the Central and Piedmont areas of North Carolina at a cost in excess of $10 million. In addition, the Company further explained that, working collaboratively with the Public Staff and DEQ, it has implemented its Water Quality Plan, pursuant to which it will continue installing new filtration treatment systems at well sites with the highest concentrations of iron and manganese at a rate of 10-15 per year and mitigating the effects of iron and manganese by increased system flushing and tank-cleaning.

The Company also addressed customer concerns about customer service. In working with witnesses such as customer witness Daniels, Aqua NC was able to understand and explain the cause of specific occurrences of periods of brown, discolored water experienced by customers, system alerts of adverse water issues that were issued to customers not affected by the alerts, and the Company's general response time upon learning of the issues that were the subject of the customer witnesses' complaints. In some cases, the discolored water was the expected but short-lived result of processes related to Aqua NC's efforts to remove or lessen the impacts of iron and manganese, and in other cases worker mishaps or errors in the normal course of work exacerbated water quality conditions, but, according to the Company, such situations were promptly corrected resulting in the return to clear water status.

The Company explained that some of the customer concerns were due to communication issues between the Company and the customers. There were some Aqua NC errors in communication but there were also failures related to customer misunderstanding of proper communications from the Company. By speaking directly with testifying customers, Aqua NC learned more about improving the communications process and made, and continues to make, adjustments and corrections to improve the overall customer service experience. For example, to improve its call center communications, the Company disabled the interactive voice response (IVR) feature utilized by its call center. Previously, IVR was used to provide an automated response about the status of service issues based on a caller's zip code. Aqua NC described the unintended problems caused by the IVR function stating, "When a zip code was entered, the automated response could indicate that a general service issue existed for an entered zip code; however, zip codes have large populations and have multiple subdivisions within them. This may result in customers being misinformed or confused about specific issues in their area." The IVR function was eliminated from Aqua NC's call system effective July 11, 2018. Tr. Vol. 12, p. 117.

The Company discussed other efforts to improve on customer communications. Examples given by the Company were a program (Close the Loop) started in the second quarter of 2018 to make sure customers are contacted after their calls and complaints have been addressed; creation of a website to educate customers about iron and manganese issues and Company efforts to improve related water quality; and a planned customer focus group to allow some customers to provide input and give direct feedback on Company efforts that deliver intended results and those that may not work as well. See Tr. Vol. 5, pp. 151-55.

Quality, Remediation Efforts, and Communications

Company witness Crockett addressed water system compliance for Aqua NC with a focus on DEQ's secondary water quality standards. He explained the difference between primary and secondary water quality standards and established that Aqua NC complied with all primary water quality standards, with the exception of an issue in the first quarter of 2018 concerning the Town of Pittsboro's delivery of water to Aqua NC that exceeded the limits for the disinfection by-products Maximum Contaminant Level for Total Trihalomethanes. As to that issue, he explained that Aqua NC and the Town were working to resolve the underlying problems.

Witness Crockett acknowledged the Company's difficulties with elevated levels of iron and manganese, which adversely affect the Company's compliance with DEQ secondary water quality standards. He described the 2016 change in DEQ enforcement policy, which produced a profusion of NODs triggered by exceeding secondary limitations for iron and manganese. Since February 2016 Aqua NC has received 68 Notices of Deficiency (NODs) from the Public Water Supply Section of DEQ. The NODs involved more than 50 Aqua NC water systems and approximately 70 different wells with elevated concentrations of iron and manganese, with most reporting manganese above 0.3 mg/L.

Witness Crockett testified that iron and manganese occur naturally in groundwater in certain locations in North Carolina. He explained that, when groundwater containing iron and manganese is pumped to the surface, once the iron and manganese come into contact with oxygen, they present as solid dark-colored particles in the water, which can discolor the water and can stain clothing and household appliances and plumbing fixtures. Tr. Vol. 7, pp. 46-47. He noted that, while iron and manganese pose what he termed primarily "aesthetic" concerns, the EPA has established a lifetime health advisory for manganese and suggests that levels above 0.3 mg/L may have the potential to impact the health of children. Id. at 47.

Witness Crockett testified that high concentrations of iron and manganese can be remediated through filtration, installed either centrally or on individual customers' premises; flushing, either by the Company at a system level or by individual homeowners to clear the system of sediment; sequestration using chemicals to suspend iron and manganese thereby keeping water clear at the tap; or a combination of any or all of the above. He discussed the merits and shortcomings of the different options, including the relative costs.

Witness Crockett discussed the Company's Water Quality Plan, which works to develop a common framework, with the support of the Public Staff and DEQ, to address secondary water quality issues, with the goal of expediting infrastructure improvements through increased capital spending to install greensand filters to address water quality issues for the customers. Id. at 52-53. He explained that non-capital operational improvements like increased tank cleaning and pipe flushing to address and lessen iron and manganese levels are also emphasized under the Plan. Id. Witness Crockett further explained that, under its Water Quality Plan, Aqua NC sites for remediation have been divided into four groups according to the levels of iron and manganese, with Group 1 sites being prioritized for the earliest treatment or remediation for public health protection, followed by Group 2 and so on. Id. at 53-54. Factors used to determine the groupings and order of prioritization shown on witness Crockett's summary of the Plan (Crockett Exhibit A) were (1) notice of deficiencies; (2) scientific, engineering, and health data; and (3) customer complaints.

Committed to providing water that is both safe for human consumption (a reference to DEQ's primary drinking water standards) and aesthetically pleasing (a reference to DEQ's secondary water quality standards), the Company's Water Quality Plan calls for increased capital investment for installation of greensand filters going forward according to the prioritization schedule at a rate of 10-15 per year. This strategy to install filters is estimated to perhaps require an investment $28,000,000 over the next seven years. Company witness Crockett acknowledged that Aqua NC appropriately considers least cost remediation measures, taking into account the efficiency of such measures, prior to the installation of greensand filters. Tr. Vol. 9, p. 117.

Aqua NC President and witness Becker also underscored the Company's work and commitment to improving water quality despite the fact that iron and manganese are prevalent elements in North Carolina aquifers in the Company's service territory. In addition to expressing commitment to the Water Quality Plan, he testified in further detail about the Company's efforts to deal with the iron and manganese issue since its last rate case decided in 2014. He described efforts to meet and work with DEQ and the Public Staff to develop ideas and plans for improving water quality for customers negatively affected by this issue. See, e.g., Tr. Vol. 5, pp. 38, 64; Tr. Vol. 7, p. 50. His testimony revealed that the Company has also been willing to consider alternatives to Aqua NC's wells for source water. He relayed an occasion, when at the urging of the Public Staff, the Company evaluated purchasing water from the Town of Holly Springs to serve one of its Brayton Park systems.

Witness Becker gave an account of remediation efforts over the last several years, including better flushing and tank washing protocols, sequestration, and filtration. He touted the over $90 million of investment the Company made in its systems since its last rate case and the over $10 million invested in the installation of 80 greensand filters. Despite the Company's efforts, witness Becker acknowledged the iron/manganese issue is difficult and negatively impacts the lives of many of Aqua NC's customers. He acknowledged that the Company made a misstep in incurring expense to sequester with SeaQuest® but not flushing on the manufacturer's recommended schedule of 30, 60, 90 and 120 days. He agreed that once the SeaQuest® began acting on the iron and manganese, customers would have experienced higher concentrations of the metals in their water if the systems were not properly flushed. Multiple systems were not flushed for extended periods of time, but the Branston system was not flushed for three years. See, e.g., Tr. Vol. 14, pp. 81, 83-86. Witness Becker was aware that DEQ had issued multiple notices of deficiency at sites where SeaQuest® had been introduced but flushing had not been properly performed.

With regard to flushing as a means of improving water quality, witness Becker testified about the Company's recommendation that customers flush the pipes at their premises on occasion. Currently, the customers are billed for the water used in this flushing process. When questioned by the Commission about bill credits to customers for such flushing, Aqua NC witness Becker stated that the Company is not opposed to exploring options to provide customers bill credits in exchange for their flushing at Aqua NC's request. Tr. Vol. 5, pp. 189-190.

Witness Junis, in discussing the due diligence the Public Staff employs when evaluating treatment options, testified regarding operational changes that can be made to improve water quality including the optimization of well pumping capacity and water pressure. Tr. Vol. 11, pp. 71-75.

With regard to its wastewater treatment systems, Aqua NC was cited and assessed civil penalties for 10 Notices of Violation (NOVs) issued by DEQ's Division of Water Resources (DWR) for non-compliance that occurred during the test year at three of its 59 wastewater treatment plants. Ex. Vol. 5, pp. 14-95; Tr. Vol. 5, pp. 62-93. The three plants were acquired but not installed by the Company. Id. at 126, 180. The violations at two of the plants were related to weather conditions and hurricanes that affected the areas where the plants are located. While the violations varied, they generally stemmed from the unauthorized release and discharge of sludge.

According to witness Becker, the non-compliances were addressed and corrected. The Company's shareholders incurred the expense related to the fines and penalties assessed for the violations, as well as attorney fee expense related to these violations before DWR. Id. at 93-94. Witness Becker testified that the plants receiving the NOVs are now in compliance. Id. at 112.

Witness Crockett and witness Becker also testified about Aqua NC's new Customer Communication Plan, which utilizes a range of approaches, including a website, to educate and communicate with customers, especially on water quality issues. Witness Becker addressed the heightened attention to customer communication across the Company. He explained the Company's statewide initiative, launched in May 2018, designed to follow up with customers who call about certain service issues, requiring the dispatch of a field technician. Named the "Close the Loop" program, it requires an initial follow-up call attempt by the field technician, after having left a door tag advising of completion of service, plus a secondary follow-up call made by designated Aqua NC office personnel a week after the service call. The second call by an office employee is focused on the customer's experience, whether the customer's issue was addressed and resolved, and answering any additional questions the customer may have. The purpose of the "Close the Loop" program is to improve customer awareness of necessary work performed on the water system or at the customer's premises, as well as to provide an additional or supplemental line of communication to answer questions and address issues.

Regulatory Oversight and Compliance

Ordering Paragraph No. 11 of the Sub 363 Order requires the Public Staff and Aqua NC to file semi-annual written reports to address secondary water quality concerns affecting the lesser of 10% or 25 customers in an individual subdivision.

Public Staff witness Junis testified that he reviewed Aqua NC's customer complaint records related to water quality issues from January 2016 through June 2018. He noted that Aqua NC tracked complaints received during normal business hours separately from those received after business hours, and that the Company records reflected different information in different formats. Tr. Vol. 12, p. 115.

Witness Junis testified that the Company issues a Lab D work order (LABD), a category of work or service order, in response to discolored water complaints received via phone calls made during business hours and online inquiries that necessitate a work order. He further testified that the Company uses LABDs to track, quantify, and report on customer water quality complaints for the purpose of complying with Ordering Paragraph No. 11 of the Sub 363 Order. Id. at 115-116. When witness Junis discovered a discrepancy between the numbers of complaints reported in Aqua NC's Eighth Semi-Annual Report Concerning Secondary Water Quality Concerns filed in Docket No. W-218, Sub 363A, and the actual number of complaints of which he was aware, he realized the Company appeared to be under-reporting complaints in the semi-annual compliance report because calls and complaints received outside of normal business hours were not being issued LABDs and, therefore, were not accounted for in the report. He testified that he then had concerns that customer complaints had been under-quantified in previous reports and that additional individual subdivision service areas may have met the 10% / 25 customer threshold established by the Commission and should have been reported on pursuant to the Sub 363 Order. Id. Witness Junis engaged in further investigation and was able to confirm that the joint semi-annual reports had in fact under-reported the number of water quality complaints received by the Company. He recommended that the Company be specifically directed to fully incorporate after-hours complaints (which the Company is now doing in conjunction with the Public Staff), and that the Seventh and Eighth Semi-Annual Reports be supplemented with additional information about after-hours complaints.

Aqua NC witness Becker testified on cross-examination that the Company outsources after business hours customer complaint call response for reasons related to cost. He further testified that the customer service agents who respond to calls received after business hours only handle emergency-related calls, and do not have the ability to track calls by issuing LABDs that customer service agents who respond to business hours calls do. Witness Becker stated that Aqua NC could potentially give after-business-hours customer service agents access to the same call tracking system, but doing so would involve additional expense. He acknowledged that he understood it was the Commission's intent that the reporting requirements set out in Ordering Paragraph No. 11 apply to all customer complaint calls, not just those received during business hours. He disclosed that Aqua NC is testing a procedure to give after-business-hours customer service agents the ability to issue LABDs. Tr. Vol.14, pp.101-103.

Ordering Paragraph No. 12 of the Sub 363 Order requires Aqua NC to provide the Public Staff with communications by and between Aqua NC and DEQ regarding water and wastewater quality concerns. Public Staff witness Junis testified in the instant proceeding that the Public Staff has actively worked with DEQ and Aqua NC to address secondary water quality issues and methods to identify and prioritize water systems in most need of a filtration system. Witness Junis further testified that the Public Staff, as its contribution to the meetings and discussions, seeks to balance cost effective solutions, including operational improvements and filtration, with safe, reliable, and clean water utility service. Tr. Vol. 12, p. 24. While he did not testify regarding Aqua NC's compliance with the Commission's directive from the Sub 363 Order, the Public Staff recommended that the Commission order Aqua NC, in the instant proceeding, to convey to the Public Staff conversations with, reports to, and the recommendations of DEQ regarding the water and wastewater quality concerns being evaluated and addressed in Aqua NC's systems in a timely manner. He recommended that such communication be in a written format and provided, at a minimum, on a bi-monthly basis and that Aqua NC be required to provide the Public Staff with copies of: (a) Aqua NC's reports and letters to DEQ concerning water quality concerns in its systems; (b) responses from DEQ concerning reports, letters, or other verbal or written communication received from Aqua NC; and (c) DEQ's specific recommendations to Aqua NC, by system, concerning each of the water quality concerns being evaluated by DEQ. Id. at 26.

In response to the recommendation of the Public Staff, Aqua NC took the position, through the testimony of witness Becker, that the provision is unduly burdensome, unnecessary, and is less productive than other modes of communication and reporting. Tr. Vol. 14, p.16. Witness Becker testified that Aqua NC is always willing to meet with the Public Staff and/or DEQ upon request or upon specified intervals to discuss issues and to provide relevant information but that because Aqua NC is constantly in conversation with its regulators, requiring this level of formality and reporting would likely hinder the open lines of communications that Aqua NC has worked to have with its environmental regulators. Id. Additionally, witness Becker testified that placing responsibility on Aqua NC to reduce to writing notes on all "conversations" with DEQ personnel is onerous, susceptible to abuse and misinterpretation, unproductive, and does not contribute to the parties' collective ability to understand and act on solutions. Witness Becker expressed concern regarding the possibility of misunderstanding, which he testified could be avoided if the entities seeking to communicate simply meet jointly with each other at specified intervals or on topics specified, exchange information, and jointly report. Id. at 16-17. Finally, witness Becker testified that the Public Staff can verify DEQ's position, leaving no opportunity for miscommunication and no concern about reliance on anyone else's interpretation, through direct communication between the agencies. Id. at 17.

Discussion and Conclusions

The evidence before the Commission establishes that the overall quality of water service provided by Aqua NC, viewed on a companywide and systemwide basis, is adequate. The Company is in compliance with federal and state primary health-based water quality standards, except, at the time of the hearing, trihalomethanes were present in water the Company purchased from the Town of Pittsboro. The Company and the Town of Pittsboro are working to resolve that issue. While 26 of Aqua NC's water systems have been noted for deficiencies related to secondary water quality standards, the Company is actively working with DEQ and the Public Staff to bring them into compliance and, elements addressed by secondary water quality standards are not considered to pose health risks; EPA's recent health advisory for manganese in excess of 0.3 mg/L did not change this status. However, the record also convincingly demonstrates that many of Aqua NC's customers for some time have been and still are paying for and receiving water from Aqua NC that they are unwilling to drink or to use for other purposes because it is not just unclear or cloudy but is brown and, on occasion, opaque. These customers incur the expense of purchasing bottled water in addition to paying Aqua NC for water utility service.

Moreover, water is required for uses other than ingestion. It is used for general cleaning, laundry, and in appliances and fixtures, among other uses. The iron and manganese-laden water supplied by Aqua NC to a not insubstantial number of its customers cannot be used for these general household purposes. Customers who try to use the water for such non-consumptive purposes find that they have to frequently buy new clothes and replace or repair appliances such as dishwashers and coffeemakers more frequently than they should because these items are stained, damaged, and ruined by the discolored, sediment-heavy water. In addition to the extra expense of repairing and replacing clothes and household fixtures frequently, many of these customers, in an effort to render their water clear and useable, pay to have in-home filtration systems installed. Filters used as part of their systems have to be replaced more frequently than otherwise because they clog quickly due to the heavy amount of sediment in the water from the Company systems.

While the water in question meets state and federal health-based regulatory standards, it does not always sufficiently meet reasonable expectations for non-consumptive domestic uses. As a result, due to the iron and manganese in the Aqua NC supplied water, affected ratepayers effectively incur notable expenses beyond the charges on their monthly bills, as well as stress and anxiety. This Commission's jurisdiction and authority encompasses more than compliance with health-based regulatory standards. The Commission is concerned that water supplied by its regulated utilities is useable for its intended purposes and does not cause, as a result of poor quality, unnecessary economic harm and damage to ratepayers and their personal property.

N.C.G.S. §62-43(a) makes it clear that the Commission has responsibility for the overall suitable quality of water and that this responsibility is not restricted or limited by the regulatory determinations of EPA or DEQ concerning human health and environmental protection.

Just as it did in its May 2, 2014 Order ruling in the Docket No W-218 Sub 363, the Commission concludes that the service-related concerns expressed by customers, especially including water quality concerns related to elevated concentrations of iron and manganese, necessitate further action by the Company. The Commission recognizes that since it issued its ruling in 2014, the Company has expended a great deal of time, effort, and investment addressing these "secondary" water quality issues; the Commission does not take the Company's effort lightly. The number of customers testifying and filing written statements about water quality concerns, compared to the number heard from during the pendency of the Sub 363 docket, has declined, but the repeat nature of the complaints about intolerable water conditions, experienced over many years, leads the Commission to conclude, that, despite its extensive efforts, Aqua NC has not yet satisfactorily resolved the water quality issues in some of its individual systems. In systems with elevated iron and manganese levels, quality of service is not adequate. Moreover, it appears that some of the same concerns that were the subject of the Commission's several directives in its Sub 363 Order remain unresolved. Accordingly, it is the Commission's determination that Aqua NC must make further and continued efforts to address customer service and water quality-related issues concerning elevated levels of iron and manganese in water supplied from Aqua NC water systems.

At a minimum, the Commission expects the Company to evaluate and implement operational changes and improvements, including those testified to by the Company, such as tank cleaning and those described by the Public Staff; for example, the optimization of well pumping capacities before investing in treatment options.

Among other efforts required of the Company to address water quality issues is an appropriately aggressive flushing program for each affected system and adherence to the flushing schedule recommended by manufacturers of sequestering products used by the Company to treat iron and manganese. The Commission concludes in accordance with the Company's admission that Aqua NC failed to follow the flushing schedule recommended following the introduction of SeaQuest® into the water system. This failure had the effect of increasing the iron and manganese in the water going to the Company's customers; exacerbating the problems some customers experienced due to poor water quality. The Company is on notice that there cannot be a repeat of this mistake and that the Commission may consider the imposition of appropriate penalties should the value of using a sequestering agent be negated in the future by the Company's failure to follow an appropriate flushing protocol.

On the subject of flushing, as noted above, when Aqua NC recommends to its customers that they flush the pipes at their premises, the customers who undertake this flushing are charged for the water used in the process. When questioned by the Commission about bill credits to customers for flushing, Aqua NC witness Becker stated that the Company is not opposed to exploring options to provide customers bill credits in exchange for their flushing at Aqua NC's request. Tr. Vol. 5, pp. 189-190. The Commission is of the opinion that the Company should work with the Public Staff to develop a policy and procedure for providing customers a bill credit when Aqua NC recommends individual premises flushing to address water quality issues.

The Commission further concludes that Aqua NC's Water Quality Plan, intended to address water quality issues through increased capital investment and improvements to operations including installation of filters and treatment such as sequestering, as well as improved tank cleaning methods and procedures and increased flushing, appears to be a reasonable start and thoughtful effort to improve the unresolved water quality issues that have continued over the last several years. While the Water Quality Plan as presented in this docket appears to be workable, the Commission expects that as the Company and the Public Staff, in conjunction with input from DEQ, will monitor the implementation and effect of actions taken in accordance with the Plan and that the Plan may need to be adjusted over time. The Commission appreciates and encourages the Company's and the Public Staff's attention and simultaneous commitment to addressing the serious water quality issues in the Company's affected water systems and to maintaining affordable service in all of its service areas in North Carolina. While quality and affordability interests must be balanced, the Commission is mindful that ratepayers must receive useable water in exchange for the rates they pay.

With regard to wastewater service, the Commission finds and concludes based on the record before it that the service is adequate and the Company operates its wastewater plants in a prudent manner. While the Company received NOVs for events and conditions at three of its 59 wastewater plants, Aqua NC corrected the situations and has not sought recovery from ratepayers for fines, penalties, and attorneys' fees related to these NOVs. The Company acted appropriately to return the plants to full compliance and at the time of the hearing the plants were in fact in compliance. Given the nature of wastewater plants owned by investor-owned utilities in North Carolina, the Commission does not find that the mere occurrence of isolated instances of non-compliance necessarily means that overall companywide wastewater service is inadequate.

Aqua NC's efforts to improve its customer service through its Customer Communications Plan demonstrate the Company's commitment to improving its customer relations by putting enhanced protocols in place to assure responsiveness to customer inquiries, concerns, and service calls. The Plan, which is tied to the Water Quality Plan, should help the Company inform and educate customers about quality improvement plans, including such implementation aspects as cost impacts of improvement measures, the work involved, and the timing of such work. Again, the Commission expects that any communications plan will be adjusted over time to meet current concerns and to incorporate lessons learned throughout the process of building a relationship of trust with customers.

Finally, the Commission concludes that in light of the persistent water quality issues related to iron and manganese, it remains appropriate that Aqua NC continue to follow the reporting requirements established in Ordering Paragraph 11 of the Commission's May 2, 2014 Order ruling on the Company's request for rate increase in the Sub 363 docket, among others to be noted in the Ordering Paragraphs of this Order. Ordering Paragraph No. 11 of the Sub 363 Order required the Public Staff and Aqua NC to file semi-annual written reports to address secondary water quality concerns affecting the lesser of 10% or 25 customers in an individual subdivision. In complying with this reporting requirement, it was necessary that the Company keep an accurate count of the numbers of water quality complaints it received from all its customers. As the Public Staff came to learn, and as later confirmed by Aqua NC, the Company failed to fully apply the reporting requirements of Ordering Paragraph 11 to all of the customer complaints it received because it did not capture for compliance purposes the complaint calls received outside the normal business hours. The Company shall correct this counting error and fully comply with the reporting requirements of Ordering Paragraph 11 of the Sub 363 Order and shall comply with all other reporting requirements identified in this Order.

In addition, so that the Public Staff may be effective in working with Aqua NC to develop solutions and make recommendations to the Commission for resolving the water quality concerns discussed throughout this Order, the Commission finds, as it did in the Sub 363 Order, that it is appropriate for Aqua NC to make reasonable efforts to keep the Public Staff informed of its communications with DEQ related to these water quality concerns. The Commission is mindful of the concerns expressed by Aqua NC witness Becker regarding formality and administrative burden and directs that the sharing of information required by this Order not be in a formal "report" format but rather in a less formal written exchange whereby the Public Staff is simply provided with copies of written communications or alerted to the fact that a meeting or conversation took place and the salient points discussed at the meeting or conversation. Additionally, the Commission agrees with witness Becker that direct communication is the most effective way to mitigate the possibility of miscommunication and encourages the Company and the Public Staff to meet with DEQ jointly and regularly for this reason.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 35-52

The evidence supporting these findings of fact is contained in the Application and Aqua NC's NCUC Form W-1 filing, the testimony and exhibits of Company witnesses Becker, Thompson, and Kopas and Public Staff witnesses Cooper, Henry, Boswell, and Junis, the Sub 363 Stipulation, and the record in this proceeding.

The following table summarizes the differences between the Company's level of rate base from its Application and the amounts recommended by the Public Staff:

Item	Company Application	Public Staff	Difference
Plant in Service	$485,345,163	$488,061,240	$2,716,077
Accumulated depreciation	(154,951,542)	(155,018,156)	(66,614)
Contributions in aid of const.	(189,897,507)	(194,983,782)	(5,086,275)
Accum. amortization of CIAC	70,605,175	70,516,485	(88,690)
Acquisition adjustments	1,925,745	2,055,735	129,990
Accum. amort. of acquis. adj.	1,044,591	1,040,444	(4,147)
Advances for construction	(4,305,936)	(4,467,841)	(161,905)
Net Plant in Service	209,765,689	207,204,125	(2,561,564)
Customer deposits	(379,445)	(379,445)	0
Unclaimed refunds	(193,255)	(193,255)	0
Accum. deferred income taxes	(35,329,190)	(24,791,481)	10,537,709
Materials and supplies inventory	2,405,967	2,405,967	0
Excess capacity adjustment	(1,233,706)	(1,589,551)	(355,845)
Working capital allowance	4,626,122	4,434,355	(191,767)
Original cost rate base	$179,662,182	$187,090,715	$7,428,533

With the Stipulation and revisions made by the Public Staff in its supplemental testimony and Revised Supplemental Cooper Exhibit I, the Company does not dispute the following Public Staff adjustments to rate base:

Item	Amount
Update advances for construction	($161,905)
Remove costs related to future customers	5,992
Adjustment for Mountain Ridge AIA	75,090
Update Mid South growth PAA to 6/30/18	54,900
Accumulated amortization of acquisition adjustments	(4,147)
Adjustment to working capital	(191,767)
Adjustment for accumulated deferred income taxes	10,537,709
Total	$10,315,872

Therefore, the Commission finds and concludes that the adjustments listed above, which are not contested, are appropriate adjustments to be made to rate base in this proceeding.

Based on the testimony of Company witnesses Becker and Thompson, the Company disagrees with the following Public Staff adjustments to rate base:

Item	Amount
Adjustment for excess capacity	($355,845)
Adjustment for post-test year plant additions	2,648,394
Adjustment for meters and meter installations	(4,005,618)
Adjustment for wastewater capacity-Johnston County	(849,586)
Adjustment for imputed CIAC-Buffalo Creek	(324,684)[1]
Total	($2,887,339)

Excess Capacity Adjustment

Public Staff witness Junis testified that the Company's general rate case filing in this docket included excess capacity adjustments for the Carolina Meadows, The Legacy at Jordan Lake, and Westfall (aka Booth Mountain (BM)) wastewater treatment facilities. He stated that the excess capacity percentages recommended by Aqua NC are identical to the calculations done in Aqua NC's last general rate case, Docket No. W-218, Sub 363. In his prefiled testimony, witness Junis referred to Aqua NC's Application Exhibit C-1-ANC-10 for the Company's proposed calculations for excess capacity in this proceeding which reflected the following percentages: 23.83% for Carolina Meadows; 94.33% for The Legacy at Jordan Lake; and 92.44% for Westfall.

Based on the calculation methodology established by the Commission and used in Aqua NC's prior two general rate cases, witness Junis calculated the Company's wastewater excess capacity as follows:

[1] Due to a formula error on Public Staff Cooper Supplemental Exhibit I, Schedule 2-3 Revised, the actual amount in dispute of ($315,687) for the imputation of CIAC, less accumulated amortization of CIAC of $8,997 or $306,690 was inadvertently presented in the Public Staff's exhibit as ($324,684) [$315,687 plus $8,997].

Plant Name (a)	Installed Capacity (gpd) (b)	EOP REUs (c)	Flow (EOP x 400 gpd) (d)	Excess Capacity (1 – d/b) (e)
Carolina Meadows	350,000	607	242,800	30.63%
The Legacy at Jordan Lake	120,000	184	73,600	38.67%
Westfall (BM)	90,000	145	58,000	35.56%

Further, witness Junis stated that Public Staff witness Cooper implemented the updated excess capacity percentages and plant, net of accumulated depreciation and contributions in aid of construction (CIAC), to calculate the excess capacity adjustment proposed by the Public Staff.

Witness Junis also testified, in pertinent part, that on July 27, 2018, he and witness Darden inspected the WWTP at Carolina Meadows. Regarding their inspection of the Carolina Meadows WWTP, witness Junis noted that the Company completed a major modification and rehabilitation project in May 2018. Existing tankage was converted into a 90,000-gallon equalization (EQ) tank and a separate 60,000-gallon digester. In addition, a mechanical fine screen was installed to improve sanitation and to help prevent rags and other debris from damaging equipment and decreasing the efficacy of the treatment process. The building was remodeled to address mold and facilitate operational testing and chemical storage. Witness Junis further stated that Aqua NC has converted to reclaimed water for process water needs to reduce purchased water expense.

Public Staff witness Cooper testified that there was an error made by the Company in its calculation of excess capacity in this proceeding. She explained that the Company used the wrong depreciation rate in determining the net Plant in Service and depreciation expense subject to an excess capacity adjustment for the Carolina Meadows WWTP. Witness Junis corrected this mistake by reducing the depreciation rate from 5% to 4%.

Next, witness Cooper stated that she applied Public Staff witness Junis' excess capacity percentages of 30.63%, 38.67%, and 35.56% to remove from rate base the percentage of plant and accumulated depreciation related to excess capacity for the WWTPs at Carolina Meadows, The Legacy at Jordan Lake, and Westfall, respectively.

On September 5, 2018, witness Cooper filed supplemental direct testimony wherein she stated that excess capacity had been adjusted to reflect activity through June 30, 2018. As a result, the Public Staff's excess capacity adjustment increased by $518,095.

On cross-examination, witness Junis testified that Aqua NC stated in a data request response that the Carolina Meadows WWTP capacity was 350,000 gallons per day (gpd) and that it was still permitted at 350,000 gpd. Tr. Vol. 10, p. 9. He observed that Aqua NC did not provide him with any information indicating that the recent capital spending, through June 30, 2018, reduced the plant's capacity. Tr. Vol. 9, p. 101.

Further, witness Junis testified that the Public Staff has not made excess capacity adjustments against all Aqua NC plants that are overbuilt. He explained that these three WWTPs with excess capacity adjustments are unusual in that Aqua NC "took on risk from the developer." Tr. Vol. 10, p. 8.

In his rebuttal testimony, Aqua NC witness Becker testified that the Company did not disagree with Public Staff witness Junis' excess capacity calculation (as it had been used in prior cases). However, witness Becker testified that Aqua NC recommended and requested that plant amounts determined to be excess, and removed from rate base, should be allowed to receive deferred accounting treatment. He asserted that this would allow the Company to defer the recovery of depreciation and continue to capitalize carrying costs until the capacity is actually utilized. According to witness Becker, Aqua NC's proposal would provide a better matching of the new customer revenues that are utilizing the capacity with the actual costs to economically build the capacity. He further stated that Aqua NC would review on an annual basis the amount of new capacity being utilized and the deferral treatment would stop being recorded on the Company's books for any portion once it is actually being utilized.

Witness Becker testified that deferred accounting treatment does not harm current customers. He stated that portions of assets determined to be excess would continue to be removed from rate base and related expenses associated with such portions of the assets would be excluded from the Company's current revenue requirement. He contended that allowing deferral accounting treatment will do no harm to current customers and may, in fact, provide a benefit. He opined that the current treatment of excess capacity promotes short-term decision-making on projects that may otherwise realize savings opportunities from utilizing economies of scale, a result which can ultimately result in increased costs to current customers. In contrast, utilization of deferred accounting treatment for "excess" assets would likely benefit current customers through a reduced revenue requirement via realized savings that result from a company's ability to take advantage of economies of scale when building plant.

Witness Becker continued by stating that a simple example of why utilizing deferred accounting treatment for excess capacity should be beneficial to current customers would be a utility's decision to build a 100,000-gallon plant capacity that could serve current customers and expected growth for the next three years, versus building a 200,000-gallon expansion that could be utilized for current customers and expected growth over the next six years. The 200,000-gallon expansion project is likely to be much more cost effective, even when considering the time value of money, than completing two separate 100,000-gallon capacity expansion projects to a WWTP. According to the Company, this is true even though you end up with the same capacity in the end. The second 100,000 gallons of the single 200,000-gallon project, however, is also likely to be considered excess and the utility will be prevented from recovering any depreciation expense or carrying costs until it is determined to no longer be excess when using the current excess capacity treatment. Witness Becker explained that in this example, a utility is disincentivized from taking advantage of any economies of scale and prompted to make a short-term decision to build the smaller capacity plant. Management is likely to take advantage of all economies of scale that ultimately benefit customers, but the disincentive that exists from excess capacity treatment adds an unnecessary financial penalty to the utility for doing so.

Witness Becker testified that Aqua NC requested deferred accounting treatment with respect to the excess capacity recommended for adjustment by Public Staff witness Junis that results in a $32,940 reduction of the revenue requirement in this rate case. Witness Becker maintained that the financial impact to rates that would result from deferred accounting treatment in this rate case is zero, as only the prospective related depreciation expense and any carrying costs will be deferred until the excess capacity is actually being used.

In his September 7, 2018 supplemental rebuttal testimony, witness Becker testified that he had reviewed the excess capacity adjustment that Public Staff witness Cooper made in her September 5, 2018 supplemental testimony. Witness Becker noted that, based on witness Cooper's supplemental testimony, the Public Staff's initial excess capacity adjustment had been further adjusted to reflect activity through June 30, 2018. As a result, the Public Staff's excess capacity adjustment increased by $518,095.

Further, witness Becker observed that witness Cooper did not describe the nature of and reason for her additional proposed supplemental ratemaking adjustment, but that she simply stated that a supplemental adjustment had been made and she then set forth the dollar amount of that adjustment.

Witness Becker testified that he was subsequently able to determine the nature and reason for the Public Staff's additional supplemental adjustment, which he described as follows:

> Subsequent to the test year in this case, which ended on September 30, 2017, Aqua completed an upgrade project at its Carolina Meadows WWTP. The total cost of this project was approximately $1.7 million. This project was necessary to prevent further degradation and failure of the current equalization basin. The existing equalization basin was rehabilitated, which included metal restoration, sandblasting and painting. Additional work included replacement of the degraded handrails, installation of new blowers, piping and diffusers. The digester was rehabilitated, and the existing malfunctioning mechanical fine screen was replaced with a new Huber fine screen. This work was not performed to provide additional capacity at the plant, but rather to maintain the aging and deteriorating asset already in place.

Tr. Vol. 14, pp. 63-64.

According to witness Becker, these upgrades or improvements substantially benefitted current customers and were not required for the purpose of serving future customers. The Company pointed out that the Public Staff included the entire cost of this project in the Company's rate base in the exhibits to its direct testimony; i.e., in effect agreeing that the project is used and useful and appropriate for inclusion in Aqua NC's cost of service. Furthermore, the Company noted that Public Staff witness Cooper did not make an excess capacity adjustment for this project in her direct testimony but has now done so in her supplemental testimony.

Witness Becker testified that he disagreed with the adjustment. He again stated, in his rebuttal testimony, that he did not disagree with Public Staff witness Junis' excess capacity calculation (as it has been used in prior cases) but did request that plant amounts determined to be excess, and removed from rate base, should be allowed to receive deferred accounting treatment. This continues to be the Company's position. However, in his supplemental rebuttal testimony, witness Becker stated that he was then requesting that the Commission disallow the Public Staff's excess capacity adjustment for the Company's 2018 investment at the Carolina Meadows WWTP. Witness Becker testified that this adjustment is inappropriate and unreasonable. He stated that the revenue impact of this adjustment is a reduction of $59,717.

In the case of Carolina Meadows and any of the other 58 WWTPs that Aqua NC owns and maintains, witness Becker testified that WWTP rehabilitation is often needed to maintain and preserve the plant's overall condition. At Carolina Meadows, he stated that the Company spent approximately $1.7 million in making necessary rehabilitations and upgrades. He contended that these types of needed plant upgrades should not be subject to an excess capacity adjustment that effectively disallows 30.63%, as proposed by the Public Staff, of this upgrade immediately after this investment was made by the Company. Witness Becker argued that such adjustments for these types of capital expenditures are unreasonable and unfair to Aqua NC and, ultimately, to the Company's current customers who are served by and benefitted by WWTP rehabilitations and upgrades.

Witness Becker continued by stating that the Public Staff also included as part of its initial excess capacity adjustment a similar adjustment for capital costs incurred for improvements at the Company's WWTPs prior to or during the test year for this case. In that regard, the Company included approximately $175,000 for WWTP improvements which fall into that category and which were incorporated by the Public Staff as part of the excess capacity adjustment made in its direct testimony. Through oversight, Aqua NC failed to challenge that portion of the Public Staff's initial excess capacity adjustment. For that reason, witness Becker stated that Aqua NC would accept the Public Staff's initial adjustment for purposes of this case due to the Company's failure to challenge it in its rebuttal testimony, but that the Company reserves the right to contest such adjustment in its next rate case. According to witness Becker, the Company views this accommodation as a reasonable compromise at this point in the rate case. The Company does, however, request that the Public Staff's supplemental excess capacity adjustment related to the post-test year, WWTP rehabilitations and upgrades at the Carolina Meadows WWTP be rejected and disallowed.

On cross-examination by Public Staff attorney Grantmyre, witness Becker conceded that he was unaware of the Commission having ever approved deferral accounting for Aqua NC related to plant. Tr. Vol. 15, p. 67. Further, in response to cross-examination questions regarding the Company's Canonsgate WWTP, witness Becker testified that the developer paid for the initial construction of the Canonsgate 250,000-gpd WWTP in 2005, and that this plant was fully contributed to Aqua NC. He also testified that the Public Staff explained to him that as Aqua NC did not pay for the initial construction of the WWTP that was the reason why the Public Staff did not recommend a Canonsgate overbuilt-plant adjustment resulting from the 95.7% excess capacity calculated by the Public Staff based on information provided by Aqua NC as of June 30, 2018. Tr. Vol. 15, pp. 69-70. Witness Becker acknowledged that Public Staff Becker Cross-Examination

Exhibit 17 contained a list of post-test year capital expenditures in the amount of $1.249 million by Aqua NC for the Canonsgate wastewater system.

In response to questions concerning Public Staff Becker Rebuttal Cross-Examination Exhibit 19, witness Becker acknowledged that it was the June 2, 2005 Asset Purchase Agreement between Carolina Meadows, Inc. and Aqua NC, which was executed by Aqua NC's then President, Neil Phillips, that obligated Aqua NC rather than the developer to build the expansion of the Carolina Meadows WWTP from 180,000 gpd to 350,000 gpd.

During cross-examination by the Public Staff, witness Becker reiterated his position that plant upgrade costs, which are not part of the initial capacity buildout of a plant, are different from the initial costs because they are required to benefit customers. Further, witness Becker testified that he was seeking full ratemaking recovery for the Carolina Meadows post-test year, upgrade project amount of approximately $1.7 million because application of the Public Staff's proposed excess capacity adjustment to that upgrade project would cause the Company to lose or write-off 30% of the upgrade costs. In conclusion, witness Becker stated that Aqua NC is seeking "some kind of acceptable treatment where we're not losing a third of everything we spend." Tr. Vol. 15, p.81.

Based upon the foregoing, the Commission reaches three primary conclusions regarding the WWTP excess capacity issues under consideration in this case. First, the Commission concludes that the updated WWTP excess capacity adjustment percentages of 30.63% for Carolina Meadows, 38.67% for The Legacy at Jordan Lake, and 35.56% for Westfall, as proposed by the Public Staff and agreed to by Aqua NC, should be approved. Second, the Commission concludes that it is reasonable and appropriate to apply the excess capacity adjustment percentage of 30.63% at Carolina Meadows WWTP to 50% of the Company's post-test year, upgrade project at that facility, the cost of which was approximately $1.7 million. Further, with respect to the approximately $175,000 in capital costs for improvements at the Company's WWTPs prior to or during the test year that were pointed out in witness Becker's supplemental rebuttal testimony, but deliberately not challenged by Aqua NC in this rate case proceeding due to the lateness of such discovery, the Commission concludes that, at this time, it is reasonable and appropriate to include such capital costs as part of the excess capacity adjustments in this case. Third, the Commission concludes that Aqua NC's request for authority to utilize deferred accounting with respect to WWTP amounts determined to be excess capacity, and consequently removed from rate base, at the Company's Carolina Meadows, The Legacy at Jordan Lake, and Westfall WWTPs should be denied.

With respect to the appropriate excess capacity percentages to use in this proceeding for Carolina Meadows, The Legacy at Jordan Lake, and Westfall, as testified by witness Junis and as presented in Aqua NC's Application Exhibit C-1-ANC-10 in this proceeding, Aqua NC used the identical excess capacity percentages approved by the Commission in Aqua NC's last general rate case, Docket No. W-218, Sub 363. Witness Cooper testified that she implemented the updated excess capacity percentages provided by witness Junis to calculate the excess capacity adjustment. The Commission notes that witness Junis based his updated calculation of the percentages on the methodology established by the Commission in Docket No. W-218, Sub 319, which uses end-of-period REUs and the standard of 400 gpd per connection for evaluating the used and useful portion of WWTPs as determined in Docket No. W-354, Sub 128. See Commission Order issued June 10, 1994. The Commission observes that this methodology was also used in Aqua NC's last general rate case proceeding (Docket No. W-218, Sub 363), a stipulated case. Moreover, Aqua NC has agreed with the Public Staff's updated calculation of the percentages. No party contested the methodology or the agreed-upon updated percentages. Further, neither Aqua NC, nor any other party, denied that the reason the excess capacity adjustments are appropriate in this proceeding is because Aqua NC took on avoidable risk from the developers with respect to these three WWTPs. Consequently, the Commission finds and concludes that it is appropriate to continue to make excess capacity adjustments to sewer utility Plant in Service applicable to Aqua NC's Carolina Meadows, The Legacy at Jordan Lake, and Westfall WWTPs and that the updated percentages calculated by witness Junis and agreed to by Aqua NC are the appropriate percentages for use in this proceeding.

In reaching this decision, the Commission acknowledges that Aqua NC and the Public Staff have employed a methodology for calculating the excess capacity percentages in this proceeding which was decided by the Commission in the Sub 319 proceeding when this issue was last presented to the Commission for decision. However, In the Sub 319 proceeding, the only methodology proposed for calculating the excess capacity percentages was the one advocated by Public Staff witness David Furr. Aqua NC presented no evidence in the Sub 319 proceeding as to what, in its view, a reasonable method for making an excess capacity adjustment should be. In its final Order in the Sub 319 proceeding, in its discretion, the Commission used a different calculation for calculating excess capacity percentages than that presented by the Public Staff.

The Commission reminds the parties that in the past the Commission has employed a variety of formulas or methods for making excess capacity adjustments. The Commission notes that the Company did not present any evidence in this proceeding regarding how to appropriately update its excess capacity percentages or whether future growth projections in the applicable service areas as determined by any available definitive growth documentation, such as housing permits issued, should be factored into such calculations. The Commission advises the parties that should this issue arise in a future rate case proceeding, the Commission requests that more evidence be presented by the parties regarding other formulas or methods for making excess capacity adjustments such that the Commission could determine by the weight of the evidence presented whether future growth projections or any other additional factors should be included in the approved methodology.

In regard to the Company's post-test year, upgrade project at the Carolina Meadows WWTP, the cost of which was approximately $1.7 million, the Commission has given weight to both the testimony offered by the Public Staff on this issue as well as the rebuttal testimony offered by witness Becker. This is the third consecutive Aqua NC general rate case where there has been an excess capacity adjustment for the Carolina Meadows and The Legacy of Jordan Lake WWTPs, and the second for Westfall WWTP. Public Staff witness Junis' uncontroverted testimony was that these three plants were unusual in that Aqua NC took the avoidable risk from the developers. The Commission finds credible witness Junis' testimony that the Public Staff has not made excess capacity adjustments against all Aqua NC plants that are overbuilt. An example is the Canonsgate WWTP where Aqua NC made capital improvements subsequent to September 30, 2017, totaling $1.249 million and the plant was 95.7% overbuilt as shown on Public Staff Becker Rebuttal

Cross-Examination Exhibits 17 and 18. The developer paid for the original Canonsgate construction of the 250,000 gpd WWTP in 2005 and the plant was contributed to Aqua NC. Witness Becker testified that the Public Staff explained to him that since Aqua NC did not pay for the initial construction of the WWTP, the Public Staff did not recommend a Canonsgate overbuilt plant adjustment. In that regard, the Public Staff included in Plant in Service in this proceeding the $1.249 million related to capital improvements to the Canonsgate WWTP since an excess capacity adjustment was not appropriate for this plant.

Further, there was no evidence offered that the Carolina Meadows NCDEQ-DWR permitted capacity had been reduced below 350,000 gpd subsequent to these capital expenditures. The Commission agrees with the Public Staff that the improvements to the Carolina Meadows WWTP do not change the fact that the plant's capacity is still 350,000 gpd and is overbuilt. Aqua NC's then-President, Neil Phillips, assumed avoidable developer's risks when he executed the contract with Carolina Meadows, Inc. in June 2002.

However, the Commission observes that both witness Junis and witness Becker described in their testimony the specific improvements that were made to the Carolina Meadows WWTP and the Commission is of the opinion that certain of the improvements made would most likely not be related to the size of the WWTP and therefore should not be subject to an excess capacity adjustment. For example, the building that was remodeled to address mold and facilitate operational testing and chemical storage was most likely not related to the size of the WWTP.

Witness Becker testified that the upgrade project at the Carolina Meadows WWTP was not performed to provide additional capacity to the WWTP, but simply to maintain the aging and deteriorating asset already in place. Witness Junis also described the Carolina Meadows upgrade project as being "a major modification and rehabilitation project". The Commission gives great weight to the testimony of witness Becker that WWTP rehabilitation is often needed to maintain and preserve the WWTP's overall conditions. The parties did not identify which specific plant upgrades included in the approximately $1.7 million total would relate to the size of the existing WWTP. Consequently, the Commission, in its discretion, for purposes of this proceeding has concluded that 50% of the upgrade amount should be included as a post-test year addition and 50% should be subject to the excess capacity adjustment. Should this matter be an issue in a future rate case, Aqua NC and the Public Staff should present evidence to the Commission describing the specific improvements, including the applicable costs, and how each improvement should be considered for ratemaking purposes.

For these reasons, the Commission concludes that, for purposes of this proceeding, it is reasonable and appropriate to apply the excess capacity percentage of 30.63% to 50% of the $1.7 million that Aqua NC spent on the Carolina Meadows WWTP subsequent to September 30, 2017, resulting in a total Commission-approved excess capacity plant reduction adjustment for the three WWTPs of $1,322,276.

With respect to Aqua NC's request for deferred accounting treatment, the Commission has the authority to allow deferral requests with respect to extraordinary events when considered appropriate based upon the unique facts and circumstances presented for such a request. In general, in order for the Commission to grant a request for deferral accounting treatment, the utility must show that the cost items at issue are extraordinary and unusual in nature and whether absent deferral the cost items would have a material impact on the Company's financial condition.

Based upon the evidence presented, and in consideration of the Commission's decision to include 50% of the approximately $1.7 million spent at the Carolina Meadows WWTP by Aqua NC on plant improvements as a post-test year plant addition in this proceeding, the Commission is unpersuaded that the excess capacity amounts disallowed from rate base in this proceeding are either extraordinary in type or magnitude of expenditure presented. Rather, the Commission is of the opinion that the excluded WWTP amounts are the result of a management decision by Aqua NC to assume developer risks. As a result, the determination of the financial impact on Aqua NC's earned return on common equity was not necessary for the Commission's conclusion regarding the Company's request for deferral accounting treatment.

Consequently, the Commission finds and concludes that the Company's request to utilize deferral accounting with respect to the WWTP amounts determined to be excess capacity, and consequently removed from rate base in this proceeding is unreasonable and should be denied.

Adjustment for Meters and Meter Installations

Summary of Public Staff Testimony[1]

Public Staff witness Junis testified that the stipulation between the Company and the Public Staff in Docket No. W-218, Sub 363 (Sub 363 Stipulation) stated that "the Public Staff has the right as a matter of law to challenge the reasonableness, prudency, and cost effectiveness of Aqua NC's investment in AMR-RF meters in future cases." Paragraph No. 15 of the Sub 363 Stipulation.

Witness Junis stated that the Public Staff investigated Aqua NC's implementation of water metering technologies, and he then identified and defined the following acronyms associated with water metering technologies.

> RF: radio frequency, alternative mediums for data transmittance include cellular and wired.
>
> AMR: automated meter reading, typically used to describe drive-by RF meters. The communication is primarily one-way, that is the "meter" sends data to the receiver.
>
> ERT: encoder receiver transmitter or communication module, functions as the radio and antenna for the meter to send data.
>
> AMI: advanced metering infrastructure, typically used to describe fixed point networks with strategically distributed collectors or receivers that are capable of two-way communication with the meter.

[1] Witness Junis filed supplemental testimony on September 5, 2018, which replaced in its entirety his direct testimony filed on August 21, 2018 regarding this issue.

Standard meter: the meter reader has to manually read the meter reading and log it on a handheld computer device.

Aqua NC Water: Aqua North Carolina uniform water rate division.

According to witness Junis, Aqua NC has invested $4.039 million[1] in the replacement of 17,441 standard meters with AMR meters and installation of 19,768 ERTs as part of its Meter Replacement Program. The Meter Replacement Program was initiated by Aqua America and implementation began in 2017. From 2013 through 2016, Aqua NC averaged 569 Aqua NC Water meter replacements per year. In 2017, the Company replaced 15,760 Aqua NC Water meters or an increase of over 2,600%.

Witness Junis stated that the Public Staff requested a complete and detailed cost-benefit analysis in Public Staff EDR 12. In part, the Company's response states, "Aqua NC considers this part of our company-wide (Aqua America) operationally driven Meter Replacement Program." (Response to EDR 12 Q1) In other words, Aqua America is directing Aqua NC to implement RF metering technology. Witness Junis continued by stating that in response to a March 2017 Public Staff data request, Aqua NC states:

> The company-wide program for all other states utilizes the use of a mobile AMI (AMR) (RF) technology. As Aqua NC is the only state in the Aqua America (Aqua) footprint not pervasively using AMR technology, an incremental cost benefit analysis was prepared supporting our conversion from manual read meters to RF in coordination with the meter change out program.

See Junis Exhibit 4, Response to Mobile AMR Data Request No. 2 Q1a.

Witness Junis testified that in certain northern states in which Aqua America provides water utility service, some water meters are located inside the customers' homes and there is substantial, both in quantity and duration, snow covering the outdoor meter boxes. AMR meters can be helpful and cost-beneficial in those circumstances; however, these conditions are not typical in North Carolina. North Carolina is different from many of the other states in which Aqua America provides water utility service in that a majority, closer to the entirety, of the residential water meters are located outside in meter boxes, near the street or front property line, and visible with the exception of a limited number of snow-covered days. In comparison, electric utility meters are normally located on the side of a customer's house, sometimes inside fences, and a distance away from the street.

Witness Junis further stated that in response to EDR 22 Q1, the Company provided a cost-benefit analysis calculating a monthly benefit to customers of $0.11 and with what the Public Staff believes to be significant failings: the assumption that the per meter installation cost is the same for a standard meter and an AMR meter; the incremental nature does not capture the true

[1] In Public Staff Junis Supplemental Exhibit 5, Revised Junis Exhibit 10, filed on September 5, 2018, shows an amount of $3.782 million for AMR meters and meter installation costs for the Aqua NC Water Operations rate division.

cost of multiple AMR meters over the 30.30-year depreciation life determined in the 2017 Depreciation Study prepared by Gannett Fleming Valuation and Rate Consultants, LLC, and filed in this docket on June 8, 2018, with the testimony of Company witness John J. Spanos; and no costs, only benefits, are included for developing and deploying programs and services to utilize the additional data available from the read and flag logging capabilities. See Junis Exhibit 5, Aqua NC AMR Cost-Benefit.

According to witness Junis, the AMR meters installed by Aqua NC have the following noteworthy functionalities:

- When the meter is read, the receiver collects the meter reading at that moment, a history of 40 daily readings (recorded at 12:01 am ET), and any indicators.
- The indicators or flags include tamper, high consumption, and zero consumption.

These functionalities are mitigated by the following facts:

- Onsite readers can observe whether a home appears to be occupied, for sale, or vacant, evidence of meter tampering such as tool marks, signs of extensive lawn and shrub irrigation, and signs of a leak. The meter reader can enter these comments into the handheld meter reading computer and be automatically required to verify and re-enter zero or high readings.
- After implementation of AMR/AMI, the meter is not visually inspected each month and over time the meter box can become covered with dirt and/or vegetation making it difficult and time consuming to locate when a manual verification reading or maintenance is necessitated.
- The 40 day read history is **NOT** accessible by customers.
- The customers have **NOT** been notified that Aqua NC planned to and is collecting the 40 day read history.
- The Aqua NC billing system generates an estimated bill for accounts with a high consumption or missed read without providing the customer the indicator or flag. Again, the Company is **NOT** sharing the available information to the customer.

Public Staff witness Junis testified that the Public Staff communicated concerns about Aqua NC's cost-benefit analysis dating back to early 2017. As part of the Public Staff's Mobile AMR Data Request No. 2, the Public Staff created and sent to Aqua NC a modified version of Aqua NC's analysis that resulted in an unfavorable additional cost per customer per month of $0.30, not including any potential costs related to the retirement of Aqua NC's existing standard meters. Aqua NC responded by stating in part that the "updated installation price from our national vendor is currently <$45 per meter" and "the install cost has no net impact on the incremental cost to our customers as there may only be a nominal installation difference when an RF versus a standard meter is installed." (Junis Exhibit 5) First, the Company had already performed a meter replacement program in the Brookwood Water service area in 2012 and 2013 and was invoiced by an outside contractor specific individual installation costs for the meter, meter interface unit (MIU) radio (comparable to the ERT), and mounting rod by Mueller Service Co. See Junis Exhibit 6, Sub 363 ADR 55 Q11.[1] Second, the average Itron installation cost of $69.84 per AMR meter far exceeds $45 and Aqua NC's previous installation costs of standard meters by an independent contractor. The cost-benefit analyses prepared by Aqua NC materially overstate the labor costs to replace standard meters. Itron, Inc. (Itron), the previously referenced national vendor, manufactures and sells communications equipment and services including the AMR ERTs being purchased by Aqua NC.

According to witness Junis, by making a singular conservative adjustment to the Company's cost-benefit analysis, the result is an additional cost of $0.01 per month per customer without any realized benefits to the customers. See Junis Supplemental Exhibit 1, Aqua NC Labor Adjusted Cost-Benefit. The adjustment is to simply decrease the installation labor cost of a standard meter from $71.86 to the still excessive $61.39 that the Company calculated to be its average installation cost utilizing Aqua NC personnel. See Junis Supplemental Exhibit 2, EDR 56 Q2. The exhibit includes Aqua NC's calculation and the Public Staff's calculations (highlighted in grey). However, Aqua NC's calculation vastly over quantifies Aqua NC's labor cost to in-kind replace standard meters. The Company's installation cost of $61.39 assumes an average duration of 1.5 hours per meter replacement and the internal labor cost to be $21.21 per hour. However, when conducting a meter replacement project, which would likely be entire subdivisions, the laborer would be traveling from house to house with several minutes, at most, in between. Aqua NC averaged the hourly labor costs for the following field personnel:

Facility Operator Trainee	<u>Utility Technician Laborer</u>
Facility Operator I	<u>Utility Technician</u>
Facility Operator II	<u>Utility Technician I</u>
Facility Operator III	Utility Technician II
<u>Meter Reader</u>	Utility Technician III
<u>Sr. Meter Reader</u>	

Witness Junis stated that the descriptions from job postings on Aqua America's website indicate each <u>underlined above</u> position's responsibilities include either installation of meters or replacement of inoperable meters. The job descriptions for the Facility Operator group do not include installing or replacing customer water meters. Compiling the Utility Technician Laborer, Utility Technician, Utility Technician I, Meter Reader, and Sr. Meter Reader, the average hourly labor rate is $15.23 compared to the average of $21.21 for all field employees. By utilizing the average internal labor rate of $15.23 per hour and 1.86 standard meter replacements per hour, including the 93% loading for allocated costs the same as Aqua NC, the average labor installation cost per standard meter replaced is calculated to be $15.87. See Junis Supplemental Exhibit 2. This can be compared to the per meter replacement rates quoted of $71.86 by Itron and $61.39 calculated by Aqua NC.

[1] The invoices provided are an excerpt and representative of the all of the invoices provided in response to Sub 363 ADR 55 Q11.

Witness Junis stated that the Public Staff calculated an average duration of 0.54 hours or 32 minutes per meter replacement, conservatively based upon discussions with three persons with nearly 100 years of combined experience in the water utility industry, including extensive experience replacing standard water meters in Wake and Johnston Counties. In general terms, each stated that, being generous, it should only take approximately 15 minutes, and as quick as five minutes, to replace a standard water meter, including flushing the service line and recording the meter serial number, address, and in and out meter readings. Additional time would be necessary if the meter box, yoke, or other appurtenances required replacement, which the experienced professionals estimated would require about one hour on average.

According to witness Junis, adjusting Aqua NC's cost-benefit analysis for the Company's actual average costs for the meter, installation, and ERT and the Public Staff's standard meter installation cost of $15.87, the analysis results in a $0.65 cost per month per customer for Aqua NC's AMR deployment. See Junis Supplemental Exhibit 3, Updated AMR Cost-Benefit Analysis.

Witness Junis further stated that the meters being replaced as part of the program, which are predominantly standard positive displacement meters without batteries, have had an average useful life of 17.63 years per the Company's response to EDR 40 Q2. This 17.63 year average service life is a 7.37 year or 29% reduction from the former average service life. In response to EDR 12 Q1, Aqua NC states:

> The overall meter retirements have generally been consistent with past practices as the average service life has changed from 25 years to 24 years. Newer technology could shorten the average service life of the meters, however, due to group depreciation; the remaining life method; and the variability of assets within the entire account, the asset value will be recovered over the remaining life of all assets.

See Junis Exhibit 3.

According to witness Junis, the industry recognizes a 10- to 20-year useful life before degradation of functionally and accuracy necessitate replacement. As part of the Environmental Finance Center's final report on Studies (EFC Report),[1] the Public Staff posed a number of questions including:

> 12. What is the average change-out period for residential water meters (i.e. 10 years, 15 years, 1 million gallons, etc.) for the more professionally-operated North Carolina government water utilities, such as Raleigh, Durham, OWASA, CMUD, Fayetteville PWC, Greensboro, and Winston-Salem?

[1] The Report to the Public Staff of the North Carolina Utilities Commission and Aqua North Carolina, Inc. on the Studies of Volumetric Wastewater Rate Structures and a Consumption Adjustment Mechanism for Water Rates of Aqua North Carolina, Inc. prepared by the Environmental Finance Center at the UNC School of Government was filed in Docket No. W-218, Sub 363A on March 31, 2016. https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=a7fd9d58-46ed-425f-9298-c4419f319a1f.

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See EFC Report, p. 12.

The EFC Report stated "[m]ost of the utilities use around 15 years, although two use more than 15 years and one uses less than 15." Id. Additional factors such as flow rate, velocity, water quality, and total volume/mileage can all contribute to the degradation of meter accuracy.

Witness Junis testified that the Public Staff calculated the average standard meter replacement to cost $54.30. Aqua NC has a Commission-approved meter installation fee of $70 as part of its schedule of rates. The meter cost of $38.43 is the invoiced amount from 2015 when Aqua NC was still frequently utilizing standard meters for replacements. The cost does not reflect any potential and likely discount through national or statewide buying power (the Company bought approximately 20,000 meters since its last general rate case). The average labor cost was calculated by the Public Staff to be $15.87, as described in earlier portions of witness Junis' testimony. The total average cost of standard meter replacement would have been $54.30 in comparison to the average cost of a meter replacement completed as part of the Aqua NC Water Meter Replacement Program that was $206.43, including AMR meter, ERT, meter installation, and allocated costs. The average cost of a meter replacement completed in the Brookwood Water service area was $209.66, including AMR meter, ERT, meter installation, allocated costs, and additional appurtenances as necessary.

Witness Junis stated that the Company proposes to include in its new rates the recovery of AMR meter costs. This is in addition to the AMR meter costs being recovered through Brookwood Water rates approved in the Sub 363 Order. Aqua NC has not implemented benefits to the customers while materially increasing the cost to customers. The installation of AMR meters was imprudent, unreasonable, and not justified by a realistic and comprehensive cost-benefit analysis. The customers should not pay for the increased costs as a result of unreasonable and imprudent decisions by Aqua NC management. Witness Junis recommended reductions to rate base for Aqua NC Water and Brookwood Water in the amounts of $2,834,632 and $1,399,522, respectively. The calculations are presented in greater detail in Junis Supplemental Exhibit 5. On redirect, witness Junis stated that, as an alternative position, the Public Staff's recommended reductions to rate base could be deferred with no return until the potential benefits are accessible to customers and a thorough and reasonable cost-benefit analysis justifies the recovery of the cost in rates charged to customers.

Additionally, witness Junis recommended the disallowance of any future increase to the depreciation rate of Water Account 334.00 Meters and Meter Installations due to the early retirements that resulted from Aqua NC's Meter Replacement Program. This is a potential additional cost not considered by the cost-benefit analyses and a result of the group accounting and depreciation methodologies. According to witness Junis, this is dissimilar to the cases made by Duke Energy Progress and Duke Energy Carolinas, which claimed the retired AMR assets resulting from the implementation of AMI were an extraordinary expenditure and should be amortized over a period of time shorter than the remaining life.

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Summary of Company Testimony[1]

Aqua NC witness Thompson testified that he is employed by Aqua Services as Director of Procurement. In that capacity, witness Thompson stated that he is responsible for the procurement of materials and services for Aqua America; that he manages and negotiates meter and meter related material for Aqua NC; and that he works closely with the Manager of Metrology to set meter standards and on meter related issues. Witness Thompson stated that the purpose of his rebuttal testimony was to rebut the testimony of Public Staff witness Junis as it pertains to AMR capable meters.

Witness Thompson testified that he had reviewed the testimony of witness Junis and that he did not agree with the Public Staff recommendations. Witness Thompson stated that witness Junis makes the following finding: "Aqua has not implemented benefits to the customer while materially increasing the cost to customers." Witness Thompson further stated that witness Junis concluded that: "The installation of AMR meters was imprudent, unreasonable, and not justified by a realistic and comprehensive cost-benefit analysis." Witness Thompson contested and disagreed with witness Junis' conclusions. According to witness Thompson, it is inappropriate and shortsighted for the Public Staff to conclude that the deployment of a technology is imprudent before that technology is fully deployed and its benefits can be realized.

Witness Thompson testified that the cost-benefit analyses provided by the Company in response to EDR 22 Q1 demonstrate that the decision to install AMR meters was prudent and reasonable. Witness Thompson further stated that he disagreed with the recommended adjustments or comparative calculations provided by the Public Staff. Witness Junis overlooked the immediate and tangible benefits of the AMR technology that were provided and summarized in the Company's responses to multiple EDRs. AMR technology has provided Aqua NC with a reduction in estimated bills, availability of data to support customer consumption and billing inquiries, meter reading efficiency, and eliminated manual meter reading errors.

Witness Thompson testified that AMR technology has been shown to reduce the number of estimated bills for the Company. The Business Case analysis, provided to the Public Staff in discovery, shows that in 2015 Aqua NC manual read meters had an estimated bill rate of 2.63%, or 22,071 bills per year, which exceeded three times that of Aqua America's average of 0.75%. Aqua NC meters for the same period were 14% radio read, while the other Aqua America states averaged 99% radio read meters. This benefit was further defined by providing data that Aqua NC has had an 18% reduction in estimated bills in Brookwood Water. Similarly, there was a 42% reduction in estimated bills per year for Aqua NC's Water Rate Division in the areas in which it has installed the AMR technology.

Witness Thompson testified that he disagreed with witness Junis' assertion that the noteworthy functionality of the 40 daily readings provided by AMR meters is mitigated by the fact that the 40-day read history is not accessible to customers and that customers have not been notified that Aqua NC planned to and is collecting this history. According to witness Thompson, witness

[1] The Company's rebuttal testimony was filed on September 4, 2018, one day prior to the Public Staff's filing supplemental testimony for witness Junis which included various updated calculations and amounts regarding this issue.

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Junis discounts any operational or customer benefits that are realized by the availability of this data internally; however, this view is contrary to facts understood by utility operators and managers. The 40 daily read history is available with the 100W Endpoint Receiver Transmitter (ERT) through the data logging. The 100W ERT stores 40 days of consumption information, which can be collected by the AMR system and leveraged for timely resolution to customer billing inquiries, bill disputes, and potential leak detection. The 40 daily reads stored and collected by the AMR system are used by Aqua NC in investigating customer inquiries and resolving customer metering issues. These benefits were discussed in Aqua NC's response to DR 22 Q3. Witness Thompson stated that the most recent example of this was in August 2018, when Aqua NC noted a sharp drop in well capacity in one of the Company's critical systems. Aqua NC searched the system for leaks, utilizing the AMR that had been installed in this system. In a timely manner, a meter reader captured cycle reads for all the AMR capable meters in the area to determine if there were any customers with high consumption or possible leaks. Within a few hours, Aqua NC had the information, which included a list of customers that identified abnormal consumption in several customer accounts. Aqua NC contacted the customers and notified them of a potential leak. Aqua NC verified significant leaks on two of the identified accounts and turned their water off until repairs could be made. The customers were appreciative of the efforts. This is typical of the successful utilization of the AMR system.

Company witness Thompson testified that new technology takes time to deploy and full utilization and visibility to the customer often does not occur until the Company is able to reach some level of critical mass. The worst decision is to stop deployment. The best decision is to continue deployment and increase functionality as the buildout progresses. The current level of utilization of the data collected by the AMR system is producing tangible operational and customer benefits. The first step in the process is to implement in an organized and efficient manner AMR while aged meters are being replaced. Aqua NC will continue to refine the business processes surrounding the utilization of data.

According to witness Thompson, many of the "more professionally run" utilities, as defined by witness Junis, have communicated to their customers that the benefits of the AMR or AMI technology that they have chosen to use will be realized over time and incrementally, not immediately.

Witness Thompson disagreed with witness Junis' statement that the noteworthy functionality of the AMR meters to provide indicators and tamper detection is mitigated because customers are not aware of the indicators or flag. According to witness Thompson, witness Junis inappropriately discounts the value of operational or customer benefits, simply because the data is available internally at this point, and not directly transmitted to the customer. The indicators and tamper detection collected by the AMR meters is being used by the Company in conjunction with the data logging of the 40 daily reads to prioritize service orders and to investigate potential leaks, broken or frozen meters, and theft of service. In addition, witness Thompson stated that the tamper indicators are available immediately to the meter reader and by the next day to customer service representatives and other staff through the automated report. These benefits have been discussed in detail with the Public Staff.

Company witness Thompson also testified that AMR technology provides for more efficient meter reading. The Company's Business Case analysis provided to the Public Staff in EDR Q1 shows that the projected read rate from AMR meter reads versus manual reads was projected to increase over 600%, from 37.5 reads an hour to 264 reads an hour. This information was used by Aqua NC to judge the reasonableness of the decision to implement an AMR system.

Witness Thompson also testified that he did not agree with the Public Staff's contention that the functionalities of the AMR system are mitigated because onsite meter readers can observe whether a home appears to be occupied, whether it is for sale or vacant, evidence of meter tampering, and signs of leaks. This type of observation and recording of such observation would significantly impact the meter reader's read rate, dropping to less than 37.5 reads an hour. This would require more meter reading hours and would detract from the meter reader's ability to perform work on other service orders, like meter maintenance and customer inquiry.

Witness Thompson further testified that there are additional benefits of AMR technology that witness Junis failed to acknowledge in his testimony. Employee safety and business efficiency are additional strategic and intangible benefits of the AMR program. Reducing the hours required for meter reading decreases the opportunities for accidents both onsite and in transit, such as insect/snake/dog bites, slips, trips, and falls. The AMR program also limits Aqua NC's reasons for having to enter a customer's property, due to the ability to read the meter from a distance. Aqua America is standardizing companywide to an AMR system, which provides economies of scale that are beneficial to North Carolina customers. By implementing a companywide program, the cost of the AMR program is reduced per customer as fixed and semi-variable costs, such as software, process development and troubleshooting, are spread across a broader customer base. Further, an evolving AMR program will continue to provide more timely and accurate data, increased data integrity, and advanced analytics for improved operations and service.

Witness Thompson stated that there are also future benefits to be realized incrementally as Aqua America and Aqua NC become a 100% AMR system. The industry recognizes a 10- to 20-year useful life before degradation of functionality and accuracy necessitates replacement. Aqua NC has optimized the value of aged replacement within the recognized useful life to upgrade to AMR metering technology. Although the full benefits of this program will not be realized immediately, it is prudent to install the new technology as the Company's manual meters reach the end of their useful lives in preparation for a full utilization of the AMR technology. Otherwise, a newly installed manual meter would become obsolete before its useful life has been reached resulting in an unnecessary cost to customers.

In addition, Company witness Thompson testified that the Company is converting to AMR technology in a manner that will facilitate upgrades to Advanced Metrology Infrastructure (AMI) technology as that technology becomes more cost effective. Aqua NC has ensured that the meters and meter reading and data logging technology, ERTs that are being installed as part of this program can also be utilized if later evaluations should justify an upgrade to AMI technology. Aqua NC does not believe the additional cost of AMI (repeaters, cell towers, and security) are cost-justified, presently. Furthermore, the meters being currently installed are both AMR and AMI capable, as are the 100W ERTs that are currently being used to implement the AMR program. The 100W ERTs offer an advanced two-way meter data collection using handheld (AMR), mobile

(AMR), fixed network (AMI), and combination hybrid solutions. The meter and the 100W ERTs include AMI functionality with no change required on the premise. All programming can be completed remotely should it be justified where a dense customer base supports the added fixed network cost.

According to witness Thompson, the functionality of the AMR program will increase over time and will include significant coordination with customer operations and other Company-wide initiatives, such as customer account portal and other tools to improve the overall customer experience. Internal work flows are being tested and upgraded to increase the Company's ability to utilize all the daily data collected in a timely manner with systemic business processes.

In response to witness Junis reference to "more professionally run utilities," witness Thompson stated that Raleigh, Durham, Charlotte Water, and Greensboro are all using AMR Technology. The Fayetteville Public Works Commission (PWC), OWASA, and Winston-Salem are investing in AMI Technology. Witness Thompson stated that he was also aware that Durham, OWASA, and Fayetteville PWC all used outside contractors to install the new technology.

Witness Thompson testified that he did not agree with witness Junis' adjustments to the Company's cost benefit analysis as shown in Exhibits 7 and 8 of the Public Staff's testimony. The AMR Cost-Benefit Analysis, completed by Aqua NC and provided to the Public Staff in response to EDR 22 Q1, demonstrated the cost benefit of installing AMR meters in comparison to installing manual meters. Witness Junis adjustment, shown in Junis Exhibit 7, replaces the contractor costs for installation of manual meters with an Aqua NC-calculated cost estimate of internal labor cost for a large-scale meter replacement project. Witness Junis' adjustment, shown in Junis Exhibit 8, replaces the contractor costs for installation of manual meters with a Public Staff-calculated cost estimate of internal labor costs for a large-scale meter replacement project. The adjustment also adjusts the cost of the manual meter. Witness Thompson testified that he disagreed strongly with the overall intent and integrity of the Public Staff's adjustments. The Company's Cost-Benefit Analysis was not intended to demonstrate the prudent and reasonable choice to have contractors install the AMR meters; rather, it was showing the benefit of AMR meters over manual meters. Aqua NC does not even have the internal resources to complete a large-scale meter replacement project. Finally, witness Thompson stated that he also disagreed with the magnitude of the Public Staff's adjustments.

Witness Thompson testified that he disagreed with witness Junis' estimate of $38.43 for a manual meter as referenced in the Public Staff's testimony. For information, witness Thompson stated that he attached to his testimony, as Thompson Exhibit 1, a sales quote from Mueller Systems dated March 27, 2017. The per unit pricing for a 5/8"x3/4" Manual Water Meter is $44.64 (plus tax). This pricing does include any discounts that would be available using Company buying power. The quote shows a minimum order of 12,000 units. Despite the low demand for manual meters company-wide, Aqua NC and Aqua America have a strong relationship with Mueller for discount direct manufacturer pricing. Alternatively, Aqua NC is paying $53.85 (plus tax) for an RF capable Badger Pit Meter of the same size. Witness Thompson stated that he attached the Badger Price List as Thompson Exhibit 2. Material costs of the meter boxes (pits), pit lids, resetters, and other miscellaneous material that may be required to exchange a meter were not discussed by witness Thompson, because they are required regardless of the choice to upgrade to AMR technology.

Witness Thompson further stated that he disputed parts of the Public Staff's Calculation of Average Duration Meter Exchange and Public Staff Adjusted Calculation of Average Labor Costs per Aqua NC Meter Exchange, shown on Junis Exhibit 8. Witness Junis states that the average time required to change a meter is 0.54 hour. Additionally, he states that additional plumbing work that may be required with a meter exchange, replace or repair meter box, lid, or replace resetter could take up to one hour of an experienced professional's time. Regarding these issues, witness Thompson testified that he might agree with the Public Staff's analysis, provided that the personnel assigned to such work would always be dedicated and specialized to do meter exchange work eight hours a day. In EDR 51, Aqua NC determined an average time to change a meter is one and one-half hours. This estimate was based on current Aqua NC skill level and was consistent with the labor rate used in the calculation. This analysis also assumed that meter exchanges would be completed as time allowed throughout the day and while answering other priority service calls and incurring more travel time.

Witness Thompson stated that he disagreed that the labor associated with such efficiency could be paid at a rate on average of $15.23 per hour. The labor cost used in this calculation ignores the fact that a more qualified and higher paid professional could be required to perform additional work. This partially results because installation of approximately 25% of meters will require additional work associated with the meter pit, etc.

Further, witness Thompson testified that the Public Staff's notion that the adjusted calculation of average labor costs per Aqua NC meter exchange is comprehensive of all costs that would be incurred if the Company were to perform AMR meter installation in-house is simply not accurate. Witness Junis calculates an average cost of $14.80 per install. Junis Exhibit 8. This is based on an average labor rate of $15.23 per hour. Witness Thompson stated that he did not think the average labor rate of $15.23 per hour used in witness Junis' testimony is appropriate because it is not representative of the labor rate of a specialized and experienced professional that would be required to achieve the time efficiencies stated in the testimony duration calculation. In Thompson Exhibit 3, witness Thompson stated that he had reflected the salary ranges for Meter Service Technicians I, II and III. The Meter Service Technician I position has a median rate of $23.50/hour and a job description that states "...refers more complex issues to higher level staff". The Meter Service Technician III, with an average rate of $35.80/hour, best represents the skill level of the technicians used in the 2017 AMR Meter Exchange Project and has a job description that states, "...handles complex issues and problems, and refers only the most complex issues to higher-level staff. Possess comprehensive knowledge of subject matter."

According to witness Thompson, Aqua NC replaced an average of 562 meters per year prior to the 2017 AMR Meter Exchange Project. For Aqua NC to have completed 15,000 exchanges in 2017 (May–December), additional short-term staff would have been required. There would be added cost to hire, train, and terminate, temporary staff. Additional vehicles, equipment, and staff to provide project management and oversight would also be required. These costs were not included by the Public Staff in its labor cost per hour.

Witness Thompson stated that he also disagreed with witness Junis' contention that Aqua NC's decision to hire a contractor for AMR meter exchange and ERT installation was unreasonable and imprudent. To the contrary, the Company's decision in that regard was reasonable and prudent. It is very customary within the utility industry to hire contract labor for specific projects. It is efficient, reduces liability, and avoids the need for later layoffs and perhaps workman's compensation payments. Contractor labor costs for the 2017 AMR Meter Replacement Project were $44.51 per install, excluding tax. The description of work with Itron, using Field Deployment Manager (FDM) software required a specific installation workflow to be followed to minimize service order errors, ensure accurate reading upon installation, and minimize rework. The contractor's staff specializes in meter exchange programs and achieved the efficiencies stated in previous testimony. Aqua NC utilized a competitive bid process to award this contract, ensuring that the contractor costs were reasonable and at fair, market value for the work to be performed. Aqua NC's purchasing policy requires three bids with qualified supplier vetting. Bid awards are granted on price, experience and qualifications. The average cost of $69.84 per install referenced on page 32 of the Junis testimony and provided by Aqua NC in EDR 29, included AMR meter installations of sizes ranging from 5/8" to 4", additional plumbing work associated with the Meter Pit (Box), Pit Lid, Setter Replacement, and other tasks as outlined on project invoices are shown on the Project Summary submitted as Thompson Exhibit 4.

Discussion and Conclusions

In Aqua NC's last rate case (Docket No. W-218, Sub 363), based on a stipulation entered into by Aqua NC and the Public Staff, the Company's investment in AMR meters at that time were included in Plant in Service for the Brookwood Water rate division. In Sub 363, the stipulating parties agreed that the Public Staff has the right to challenge the reasonableness, prudency, and cost effectiveness of the Company's investment in AMR meters in future cases.

In 2017 and 2018, Aqua NC installed 17,441 AMR water meters at a total cost of $3,781,679 in Aqua NC Water Operations service areas pursuant to the Company's Meter Replacement Program. In 2012 and 2013 Aqua NC installed 8,950 AMR water meters at a total cost of $1,885,507 in Brookwood Water Operations service areas. Aqua NC is requesting that its total investment in AMR meters to date of $5,667,186 be included in utility Plant in Service in this proceeding.

In the present proceeding, the Public Staff has proposed to reduce the original costs of the AMR meters and meter installations in rate base for the Aqua NC Water Operations and Brookwood Water Operations meter replacement projects by the amounts of $2,834,632 and $1,399,522, respectively, for a total reduction to combined Plant in Service of $4,234,154. The Public Staff's adjustment also resulted in a proposed total decrease of $139,727 to depreciation expense and accumulated depreciation. As a result, the Public Staff's total revenue requirement recommended in this proceeding was reduced by $473,571.

Public Staff witness Junis testified that the AMR meters installed by Aqua NC have the following noteworthy functionalities: The receiver collects the meter reading at that moment, a history of 40 daily readings (recorded at 12:01 a.m. ET), and any indicators once the meter is read. These collected indicators or flags include tamper, high consumption, and zero consumption.

However, he contended that the biggest flaw of the current status of the Company's implementation of AMR meters, dating back to 2012 in North Carolina, is the lack of data shared with customers. Witness Junis asserted that the additional functionalities of the AMR meters are mitigated by the decreased physical presence of the onsite inspection of a meter reader.

Further, witness Junis asserted that the installation of AMR meters was not justified by a realistic and comprehensive cost benefit analysis. Witness Junis testified that the Public Staff communicated concerns about Aqua NC's cost-benefit analysis dating back to early 2017. After its investigation and analysis of the Company's AMR meter replacement program, the Public Staff concluded that Aqua NC's investment in AMR technology and the utilization of a contractor for installation was unreasonable due to the combination of the price paid per AMR meter and meter installation, lack of expense savings to offset the capital cost, and lack of quantifiable benefits passed along to customers. Aqua NC disagreed with the Public Staff's analysis and conclusion.

The Commission notes that both the Public Staff and Aqua NC expended considerable time and effort in presenting their respective positions to the Commission concerning this issue. Based upon our careful review of the testimony, the Commission reaches the following conclusions on the key components of this issue:

1. Aqua NC's decision to install AMR meters versus standard meters –

The Public Staff contended that Aqua NC's meter replacement program was initiated by its parent company, Aqua America, and the decision was not supported by an appropriate cost-benefit analysis.

Aqua NC stated that, although the meter replacement program was initiated by its parent company as part of a company-wide initiative, the installation of AMR meters was performed in conjunction with its normal meter replacement program and fully supported by a cost-benefit analysis.

The Commission concludes that it was not unreasonable for Aqua NC to select the newer AMR technology rather than the standard meter for its normal meter replacement program. Standard water meters utilize older technology whereby the meter reader has to manually read the counter located on the meter and log the reading on a handheld computer device. A new standard meter has very limited, if any, ability for adjustment for future technological advances.

The Commission determines that it would have been inappropriate for Aqua NC to invest in older technology in 2012 and 2013, and then again in 2017-2018 when the real world situation is that we live in a time when technology improvements are increasing rapidly. The Commission finds that the older standard meter technology, which has an average useful life of approximately 17 years, would not provide the required benefits to the Company or the expected benefits from its customers for a period extending 17 years into the future. The Commission recognizes that with the fast changing pace of technology, even the AMR technology has already been updated to AMI technology. In that regard, witness Thompson testified that the AMR technology installed by Aqua NC is AMI ready but AMI technology is not a prudent decision for Aqua NC at this time.

The Commission concludes that Aqua NC's decision to install AMR meters versus standard meters was reasonable and prudent.

In making its decision, the Commission has given substantial weight to the testimony of witness Thompson that the other Aqua America states are utilizing this technology for their regulated water utilities and that other North Carolina municipalities, including Raleigh, Durham, Charlotte Water, and Greensboro are all using AMR technology and Fayetteville PWC, OWASA, and Winston-Salem are investing in AMI technology.

2. Cost of AMR technology versus cost of standard meter –

The Public Staff expressed concerns about the cost of the AMR technology versus the cost of a standard meter. Witness Junis clearly and succinctly set forth the cost of the AMR technology versus the standard meter costs in his Revised Junis Exhibit 10. Further, witness Junis explained that the calculated average cost of $54.30 for in-kind standard meter replacement, including manual read meter, installation, and allocated costs, is comparable to the Meter Replacement Program projects completed for Aqua NC Water and Brookwood Water at average costs of $206.43 and $209.66, respectively, including AMR meter, ERT, installation, and allocated costs. Tr. Vol. 12, pp. 180-181.

The Commission recognizes that regarding Aqua NC's total investment-to-date in its AMR meter replacement program is $5.667 million. Of this total, approximately 61%, or $3.452 million, relates to the cost of the AMR meters ($1.635 million) and the ERTs ($1.817 million). In his adjustment, witness Junis excludes the cost of the ERTs ($1.817 million) and replaces the cost of the AMR meters ($1.635 million) with his calculated cost of $1.014 million for standard, manually-read meters.[1] As a result, the Public Staff's adjustment for the difference in technology, prior to considering installation costs, is $2.438 million.

The Commission understands that the Public Staff has concerns with the difference in costs between the AMR meters installed by Aqua NC ($3.452 million) and witness Junis' calculated costs if standard meters had been installed instead ($1.014 million); and recognizes that difference is not an insignificant amount. However, the Commission finds and concludes that the Public Staff did not sufficiently consider that the new standard meter is, for the most part, outdated technology from the moment it is installed. As a result, the Commission would not expect a new standard meter to be used by Aqua NC the entire length of its estimated useful life. Rather, the Commission considers it most likely that Aqua NC would find it necessary to replace its re-investment in standard meters prior to the end of their useful life which would result in additional costs to the customers in the future when the new technology is installed. When that situation occurs, the Commission recognizes that it would be evaluating the impact on customers related to both the cost of the Company's proposed new meter technology and the write-off by Aqua NC of its remaining investment in standard meters. Consequently, the Commission is of the opinion that although the cost of the AMR technology is significantly greater than the cost of a standard meter, the Commission must also consider, in making its decision, the potential long-term impacts on

[1] The $1.014 million is comprised of $38.43 times 17,441 meters installed at Aqua NC Water plus $38.43 times 8,950 meters installed at Brookwood Water.

customers resulting from the selection of each technology. Based upon the evidence presented in this proceeding, the Commission finds and concludes that it is a better long-term decision for both the Company and its customers to update to the newer AMR technology in conjunction with Aqua NC's normal meter replacement program. As previously mentioned, the Commission also concludes that Aqua NC's decision to invest in AMR technology is consistent with the decisions of the principal municipalities in North Carolina.

3. The decision to use an outside contractor for the meter replacement program versus using internal labor –

The Public Staff questioned Aqua NC's decision to hire a contractor for AMR meter exchange and ERT installation and maintained that Aqua NC should have performed its AMR installation program using internal labor. Aqua NC witness Thompson asserted that the Company does not have the internal staffing for such a large meter replacement program. He contended that the Company's decision to retain an outside contractor using a bid process was reasonable and prudent. Aqua NC stated that it obtained three bids from outside contractors before selecting the vendor, consistent with its purchasing policy. He stated that the bid awards are based on price, experience, and qualifications.

The Commission observes that there was extensive testimony presented by the Public Staff concerning the appropriate hourly cost of Aqua NC's internal labor and the average time it takes to change out a meter. The Commission acknowledges that the Public Staff evaluated these two critical factors in order to determine and quantify its proposed adjustment in this proceeding. The Commission acknowledges that such analysis by the Public Staff was articulate and relevant.

Aqua NC witness Thompson disagreed with the Public Staff's recommendation to use internal labor versus an outside contractor. Witness Thompson testified that Aqua NC does not have the flexibility in its staffing or staff with the right skills to be cost effective for large scale meter exchange replacement projects. He stated that additional short-term staff would have been required in order for Aqua NC to have completed approximately 15,000 meter exchanges in 2017. The Commission gives substantial weight to the testimony of Aqua NC witness Thompson concerning the additional costs that would have been incurred by the Company if this project had not been outsourced and that these costs were not included in the labor cost per hour calculated by witness Junis. In particular, these added costs include the cost to hire, train, and terminate, temporary outside/external staff. Additional vehicles, equipment, and staff to provide project management and oversight would also be required. The Commission also gives substantial weight to witness Thompson's testimony that the outside contractor specializes in meter exchange programs; uses specialized software that requires a specific installation workflow to be followed to minimize service work errors; ensure accurate readings upon installation; and minimize rework. Further, witness Thompson testified that the outside contractor, not Aqua NC, would be responsible for the correction of any problems occurring as a result of an issue with the installation of the meter. The Commission views the outside contractor's ongoing support and liability for problems that arise due to the installation as beneficial to Aqua NC and its customers; such benefits should be considered in the evaluation of the cost difference between internal labor costs and an external contractor. The Commission also gives some weight to the testimony of witness

Thompson that he was aware that Durham, OWASA, and Fayetteville PWC all used outside contractors to install the new technology.

The Commission finds the Public Staff's argument that Aqua NC should have performed its AMR installation program using in-house labor to be unpersuasive for the many credible reasons testified to by Company witness Thompson. The testimony offered by witness Thompson on this point was supported by substantial evidence.

For these reasons, the Commission finds and concludes that the Company's decision to retain an outside contractor for its meter replacement program was reasonable and prudent.

4. Lack of data being shared with customers —

Witness Junis expressed concern that customers are not aware of the data the Company has available concerning their daily usage. He also maintained that the lack of data being shared with customers is the biggest flaw of the current status of the Company's implementation of AMR meters. The Commission acknowledges that Company witness Becker testified that there are ways that this information can be provided to customers in the near future, such as including information on monthly customer bills and also on the Company's new water quality website explaining that such data is available, how it is being used by the Company, and how the customer can obtain access to it. The Commission agrees with witness Junis that customers should be notified by Aqua NC that the Company is collecting the 40-day read history and that this data should be shared with AMR-metered customers. Consequently, the Commission finds and concludes that Aqua NC should take appropriate measures to share the 40-day read history with AMR-metered customers and should notify the Commission when such information is being shared and also state how it is being provided to customers.

5. Expense savings to offset the capital cost and benefits passed along to customers —

The Commission is persuaded by the testimony of witness Thompson that the AMR technology has provided the Company with a reduction in estimated bills, availability of data to support customer consumption and billing inquiries, meter reading efficiency, and a reduction in manual meter reading errors. Further, the Commission finds the testimony of witness Thompson credible that the indicators and tamper detection collected by the AMR meters is being used by the Company in conjunction with the data logging of the 40 daily reads to prioritize service orders and to investigate potential leaks, broken or frozen meters, and theft of service.

Moreover, Company witness Berger, in her testimony regarding nonrevenue water loss, stated that the AWWA Manual 36 lists AMR/AMI technology as a primary method for addressing apparent losses for small water utilities because it limits "systematic data handling errors in customer billing systems, customer metering inaccuracies, and unauthorized consumption...." The Commission finds and concludes that this is another benefit of AMR technology for both the Company and its customers, especially given the fact that the Commission discusses elsewhere in this Order its decision that the Company should maintain a certain standard regarding its unaccounted for water.

The Commission gives substantial weight to the testimony of witness Thompson that the new technology takes time to deploy and full utilization and visibility to the customer often does not occur until the Company is able to reach some level of critical mass and that the functionality of the technology will increase as the buildout progresses. Further, the Commission agrees with witness Thompson that the current level of utilization of the data collected by the AMR system is producing tangible operational and customer benefits.

Based upon the testimony of witness Junis, the Commission recognizes that Aqua NC materially increased the rate of its meter replacement program in 2017. Witness Junis testified that Aqua NC averaged 569 meter replacements for Aqua NC Water Operations from 2013 to 2016 and that in 2017, the Company replaced 15,760 Aqua NC Water Operations meters for an increase in the number of replacements over 2,600%. Such significant step-up in the meter replacement program may be due to the reason testified to by Aqua NC witness Thompson that once the program is fully deployed, the benefits to the customers will increase or possibly due to his statement that Aqua NC is the only Aqua America state not pervasively using AMR technology. Nonetheless, the step-up in the pace of meter replacements in 2017 has significantly increased the Company's requested revenue requirement in the present rate case proceeding.

The Commission acknowledges that a slower rate of meter replacement would have smoothed out the effects to customers over a longer period of time. However, the Commission gives significant weight to the testimony of Aqua witnesses Thompson and Becker that the maximum benefits to customers will be achieved once the full deployment of the AMR technology is completed for both Aqua NC and its parent company, Aqua America. Although the full benefits of this program will not be realized immediately, the Commission finds and concludes that it was prudent for Aqua NC to install the AMR technology as the Company's manual meters reach the end of their useful lives in preparation for a full utilization of the AMR technology. Based upon the evidence presented in this proceeding, the Commission concludes that Aqua NC's decision to install AMR technology rather than standard, manually-read meters was the better long-term decision for both the Company and its customers.

With respect to the benefits to be achieved by Aqua America on a consolidated basis once full deployment of AMR technology is completed in all its operating states, the Commission finds and concludes that Aqua NC should inform the Commission within six months of the issuance date of this Order, regarding the specific nature of these expected benefits for the Aqua America subsidiaries as well as the planned timing of such benefits.

Furthermore, because the Commission has concluded that Aqua NC's decision to install AMR technology was reasonable and prudent, the Public Staff's recommendation that any future increase to the depreciation rate of Water Account 334.00 Meters and Meter Installations due to the early retirements that resulted from Aqua NC's meter replacement program should be disallowed is denied.

Issues Relating to Flowers Plantation Development, Johnston County, NC

The evidence supporting these findings of fact is contained in the Company's verified Application, the testimony and exhibits of Company witness Becker, Public Staff witnesses Junis and Cooper, the Stipulation, the late-filed exhibits filed at the request of various Commissioners on the record at the evidentiary hearing, and the entire record in this proceeding.

Aqua NC's 100,000-gpd Neuse Colony WWTP Expansion of 2016

The evidence supporting this finding of fact is contained in the Company's verified Application, the testimony and exhibits of Company witness Becker and Public Staff witness Junis, the Stipulation, and the entire record in this proceeding. This finding of fact is largely informational and pertains to (1) the uncontroverted description of the Flowers Plantation development in Johnston County, North Carolina; (2) the capacity used or reserved to provide water and wastewater service to the Flowers Plantation Development; (3) the current capacity and flow reduction changes to the Neuse Colony WWTP; and (4) the stipulated adjustment to include in rate base the full amount of $908,497 for actual costs incurred by Aqua NC to build the 100,000-gpd Neuse Colony WWTP expansion in 2016.

CIAC Collected Toward Total Capacity of Neuse Colony WWTP

This finding of fact revolves around a series of contracts entered into between 1999 and 2002 between River Dell Utilities, Inc., Rebecca Flowers Finch (d/b/a River Dell Company), and Heater Utilities, Inc. (Heater). Ex. Vol. 12, pp.139-140. Pursuant to the January 14, 1999 Purchase Agreement, Heater was responsible for the "construction of all necessary expansion to the WWTP up to the [DEQ] permitted discharge of 750,000 gpd." Ex. Vol. 12, p. 112. Additionally, the Purchase Agreement states, in pertinent part:

> There shall not be a purchase price for Existing Wastewater Facilities as Heater shall be responsible to construct all WWTP expansions and the existing 50,000 gpd WWTP shall be transferred to River Dell, at River Dell's sole option, without any purchase payment to Heater, once Heater has constructed the first expansion to the WWTP which will probably be 250,000 gpd.

Id. at 106.

The Purchase Agreement further states:

> Secondary Developer shall pay to Heater a cash contribution in aid of construction the same dollar amount per gallon that Heater paid for the cost of design, engineering and construction of the last WWTP expansion including regulatory mandated upgrades to the wastewater treatment process.

Id. at 127-28.

Company witness Becker testified that the current available capacity of the Neuse Colony WWTP is 350,000 gpd, which includes the recent 100,000-gpd capacity upgrade completed in 2016. The WWTP was originally permitted at 360-gpd per residential customer. Over time, the Company applied to DEQ for design flow reductions at the Neuse Colony WWTP, which when granted, reduced the adjusted daily sewage flow design rate from 360-gpd to 240-gpd per residential customer, and then again from 240-gpd to the current rating of 180-gpd per residential customer.

Public Staff witness Junis testified that the western half of the Flowers Plantation development (Neuse Colony) was to be served by the Company's Neuse Colony WWTP, while the eastern half of the Flowers Plantation development (Buffalo Creek) was to be served by purchased wastewater treatment capacity from the County's WWTP. He elaborated that, functionally, wastewater from both Neuse Colony and Buffalo Creek would flow to Aqua NC's Neuse Colony WWTP, where it then could be diverted to Johnston County based on operational needs. Tr. Vol. 12, pp.138-39. The point of delivery to the County's collection system, as originally contracted in the Amended Purchase Agreement, was to be located across Highway 42 from Aqua NC's Neuse Colony WWTP.

Witness Junis testified that the Company has sold (reserved), on the Neuse Colony side of the Flowers Plantation development, 561,001 gpd of wastewater capacity to developers through connection fees and capacity fees, including amounts sold (reserved) by Heater prior to its acquisition by Aqua NC. He argued that the Company oversold capacity in the Neuse Colony WWTP by at least 200,000 gpd beyond the daily sewage flow design rate originally permitted by DEQ. Witness Junis further contended that Aqua NC is obligated to provide treatment of wastewater that its current infrastructure may not be able to properly store and treat. He stated that if the obligated flow is realized in a short period of time, there would be an increased risk of wastewater overflows and/or incomplete treatment and contaminant exceedances. Finally, witness Junis testified that the Company collected 6% more CIAC for the Neuse Colony WWTP than the original cost of the utility Plant in Service, while purportedly overselling the plant capacity, which he contended would result in a CIAC shortage when the Company is necessitated by actual flows and the 80-90% rule promulgated by DEQ[1] to expand further the Neuse Colony WWTP or to purchase additional capacity from the County.

In his rebuttal testimony, Company witness Becker testified that witness Junis mistakenly based his opinion on the amount of sold (reserved) capacity on the Company's books rather than on the current flow design rate, which in witness Becker's opinion, is the proper basis upon which business decisions to build or buy (reserve) capacity are, or should be, made. Witness Becker stated that witness Junis utilized the 360-gpd and 240-gpd ratings that were initially used to sell (reserve) capacity at the Neuse Colony WWTP but failed to consider the additional flow reductions upon which the Company's decisions to build or buy are based. Witness Becker testified that Aqua NC's position is that the flow reductions granted by DEQ have, in effect, doubled the capacity available to sell (reserve) in the Neuse Colony WWTP. Tr. Vol. 14, p. 23. Based on the current flow rating of 180 gpd, witness Becker stated that the Company is only utilizing approximately 316,000 of the

[1] See generally, 15A NCAC 02H .0223 (detailing what actions must be taken when treatment plants reach average flows of 80% and/or 90% of their permitted capacity).

total 350,000 gpd of capacity, and that it collected CIAC in the amount of $2,294,168, exceeding the original plant cost of $2,166,023.

In summary, witness Becker asserted that the Company has increased CIAC cost recovery and reduced costs by obtaining the flow reductions from DEQ which allow more lots to be served by the existing capacity and will produce more revenues and more CIAC, to the benefit of both the Company and its ratepayers. Tr. Vol. 14, p. 36.

Discussion and Conclusions

As a preliminary matter, the Commission notes that when the owner and/or operator of a Commission-regulated wastewater utility receives payments from a real property developer in exchange for the obligation to provide wastewater collection and treatment capacity to the developers' lots, those payments, however denominated in the contract between the utility and the developer, are contractual rights most appropriately designated as reservation fees. Contrary to testimony from both parties in this case, payment of a reservation fee does not convey to the developer any ownership or property interests in the utility's WWTP facilities. Rather, the utility retains the relevant ownership or property rights in its WWTP facilities. Once the lots are connected thereafter to the utility's plant, the developer retains no rights whatsoever. While the lot owner maintains the right to receive monthly utility wastewater service from the monopoly utility indefinitely into the future, the utility owns the WWTP facilities throughout this process. Prior to the buildout of these lots, payment of reservation fees obligates the utility to reserve a given portion of capacity to the exclusion of other users, but does not bestow on the developers any ownership interests in the capacity of the WWTP.

Absent extraordinary circumstances, the reservation fees are tied to the specific real property – typically individual lots – under development by the developer. To the extent the lots covered by the contract between the developer and the utility do not require use of the capacity originally contemplated due to, for example, reduced flows from those lots into the WWTP, any capacity contemplated by the agreement, which is no longer necessary to serve those lots, is not fungible – it is not transferable by the developer to other property nor eligible for resale by the developer to another developer of a different tract of land. To the contrary, if the utility has available capacity remaining after serving lots that it is contractually obligated to serve, it may (and should) make this additional capacity available to other users in exchange for additional reservation fees. Where such additional capacity remains, the utility need not invest in additional WWTP facilities, but rather should make use of such unused capacity by serving more consumers without additional cost.

Given that the reservation fees represent cost-free capital, as long as the reservation is for capacity in the utility's WWTP, or capacity that is otherwise obtained by the utility, the fees received by the utility constitute Contributions in Aid of Construction (CIAC). The CIAC reduces the rate base of the utility, and, thus, the fixed costs that otherwise would be recovered over time in the monthly wastewater charge to ratepayers.

As a rate base/rate of return utility, Aqua NC should have in its rate base a reasonable level of investment per connection and should otherwise seek to maximize its CIAC. However, the

Company has a uniform wastewater rate structure. All of its investment in WWTPs, wherever located, is consolidated into the Plant in Service account. Designations for individual plants or other facilities owned by the utility are lost for ratemaking purposes. Likewise, all reservation fees to reserve capacity, wherever they originate, are consolidated in Aqua NC's regulatory books of account as CIAC and reduce Aqua NC's consolidated rate base accordingly. For ratemaking purposes, there is no need to match CIAC received by a particular developer to the WWTP in which Aqua NC builds or otherwise obtains from a third party capacity for the developer. Because Aqua NC's wastewater customers in Flowers Plantation development pay a uniform wastewater rate, funds that Aqua NC receives from developers with respect to property located anywhere in Flowers Plantation development, including in Neuse Colony and Buffalo Creek, benefit all Aqua NC wastewater customers. Therefore, assertions that Aqua NC overcollected CIAC from developers for its Neuse Colony WWTP are misguided.

The Public Staff divides its analysis of the Johnston County issues into a Neuse Colony discussion and a Buffalo Creek discussion and relies significantly on contracts executed in 1999 and 2002 that form the basis of this dichotomy. These contracts were executed many years ago on the assumption that Neuse Colony would be served by the Neuse Colony WWTP as expanded, and Buffalo Creek would be served, for a limited period of time, on an interim basis by the Neuse Colony WWTP, and then in the future ultimately served by capacity in the County's WWTP. As of the end of the test year in this case, all of the wastewater from the Flowers Plantation development is served by the Company's Neuse Colony WWTP, and, even if later served in part by the County at some point in 2019, the Aqua NC collection system will first transport all such wastewater to its Neuse Colony WWTP. At that point, all the Flowers Plantation wastewater loses its identity based on the origination point, and each gallon is treated the same. As of the end of the test year, therefore, the initial assumption that the wastewater from the Buffalo Creek side would be treated in the County's WWTP changed and evolved as the Flowers Plantation development has been built out. Therefore, the need to distinguish between wastewater collected within Neuse Colony or Buffalo Creek for purposes of establishing uniform utility rates does not exist at this time.

While an issue exists as to the Commission's approval of the 1999 and 2002 contracts, whatever approval the Commission granted, such approval did not extend expressly to the discrete paragraphs, subdivisions, and topics addressed within the contracts. Aqua NC has agreements with Flowers Plantation and other developers reserving capacity and requiring the payment of reservation fees, but for the most part, these agreements and the amount of reservation fees paid or uses to be made of such fees, have not been approved by the Commission. Reservation fees are deemed to be utility charges assessed in exchange for the right to receive future utility services, and, therefore, should be set forth in tariffs approved by the Commission.[1] Nevertheless, for ratemaking purposes there exists no need to match reservation fees to particular costs Aqua NC incurs to serve its customers. Aqua NC can use capacity in either its own WWTP facilities or capacity reserved from Johnston County to serve any customer anywhere in Flowers Plantation. Consequently, arguments that Aqua NC has oversold capacity in its WWTP are erroneous (setting aside the issue of contract reservations vs. reservations based on reductions in flow). Aqua NC's

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[1] See e.g., Order of Clarification, In the Matter of Carolina Water Service, Inc., of North Carolina – Investigation of Tap and Plant Modification Fees, Docket No. W-354, Sub 118, et al., p. 7 (Feb. 27, 1998).

ability to serve customers in Neuse Colony is not limited by capacity in the Neuse Colony WWTP alone. Likewise, arguments that Aqua NC collected excess CIAC within Neuse Colony are misplaced.

To adopt the Public Staff's position would result in significant unused capacity and rate base at the Neuse Colony WWTP, which could not be otherwise utilized, and consequently would not be in the interest of the ratepayers or the Company. In the final analysis, this is a matter of property rights and a question of which party owns the facility. The Neuse Colony WWTP is owned by Aqua NC and not by the developers who develop the lots. There is simply no evidence to show that the policy followed by the Company has or is likely to result in outflows, incomplete treatments, or contaminant exceedances as predicted by the Public Staff. The Commission relies on DEQ determinations as to whether sufficient capacity exists to permit appropriate treatment. Flow reductions have doubled the capacity available for the Company to sell, which increases the potential capacity (reservation) fees to be collected and revenues to be generated, benefitting both the Company and its ratepayers. Accordingly, the Commission concludes that the Company has not committed capacity in excess of what is available through a combination of capacity at the Neuse Colony WWTP and capacity obtained from the County's WWTP, and, furthermore, that Aqua NC may continue to allow reservation of additional capacity for which it collects additional corresponding CIAC, as long as Aqua NC remains in compliance with DEQ determinations and regulations in so doing.

CIAC Collected for Construction of Buffalo Creek Pump Station and Force Main

On May 14, 2002, River Dell Utilities, Inc., Rebecca Flowers Finch (d/b/a River Dell Company), and Heater entered into an Amended Purchase Agreement for the purchase of the water and wastewater utility systems serving Buffalo Creek. The Amended Purchase Agreement provided that Heater "will treat the wastewater from the land at Flowers Plantation Sections I, II and IIIB on an interim basis at [the Neuse Colony WWTP], and then in the future have the County provide bulk wastewater treatment for Heater." Ex. Vol. 12, p. 172. This provision necessitated construction of a pump station and force main to deliver the wastewater from the Buffalo Creek side to the Neuse Colony WWTP. "Functionally, wastewater from both the Neuse Colony side and the Buffalo Creek side would flow to the Neuse Colony WWTP site where it would be diverted to the County based on operational needs." Tr. Vol. 12, pp. 138-139. Additionally, the Amended Purchase Agreement states, in pertinent part:

> Heater shall pay $75,000 plus 50% of the cost of the construction of the Pump Station and Force Main ... Heater's 50% payment of the balance shall be recovered equally from the first 2,000 single-family equivalents.

Ex. Vol. 12, p. 186.

Company witness Becker testified that Aqua NC failed to include a pro rata portion of the costs of construction of the Buffalo Creek Pump Station and Force Main in secondary developer contracts executed between 2006 and 2018, resulting in approximately $315,000 of uncollected CIAC, which should have been collected as contemplated for in the Amended Purchase Agreement. Witness Becker explained that part of the reason for this oversight was the complicated and unusual nature of the 1999 and 2002 multi-party contracts. Witness Becker also noted that when the Company acquired Heater in 2004, the Company's management team underwent a significant transition of key personnel. He likewise noted that, between the time when CIAC was first collected toward the Johnston County capacity purchase and when this issue came before the Commission for adjudication, four rate cases and numerous contiguous extension filings have occurred that allowed an opportunity for regulatory oversight of the secondary developer contracts in question.

In response to questions from the Commission, witness Becker noted that Aqua NC does not have a uniform connection fee and that the connection fees fluctuate by area. He further testified that, before a lot can be connected to a wastewater collection system, it is subject to review by the Public Staff and must be approved by the Commission through an application for a Certificate of Public Convenience and Necessity or a Notification of Contiguous Extension.

Witness Junis testified, and was uncontroverted by the Company, that after removing Heater's contractually-allowable investment of $75,000, overhead, and interest costs from the $1,079,301 total cost of the Buffalo Creek Pump Station and Force Main, Heater's 50% of the balance amounts to $440,816. Heater collected the $440,816 costs that were to be recovered from Rebecca Flowers Finch (d/b/a/ River Dell Company). Ex. Vol. 16, p. 289. Witness Junis further testified that $440,816, divided equally among 2,000 single-family residential equivalents (SFREs), per the terms of the Amended Purchase Agreement, would be $220.41 per SFRE. According to witness Junis, Aqua NC failed to invoice developers for CIAC, to which it was contractually entitled, in the amount of $315,687[1]. Ex. Vol. 12, pp. 145-146. On examination by Chairman Finley, witness Junis testified that approximately one-third of the CIAC for the Buffalo Creek Pump Station and Force Main should have been collected prior to the end of the updated test year period, ending October 31, 2013, in Aqua NC's last general rate case in Docket No. W-218, Sub 363. Witness Junis provided a late-filed exhibit, clarifying that Aqua NC failed to invoice and collect from developers $218,999 in CIAC for the Buffalo Creek Pump Station and Force Main subsequent to the Sub 363 updated test year cutoff of October 31, 2013.

Company witness Becker disagreed with witness Junis' proposed adjustment to impute $315,687 of uncollected CIAC for the Buffalo Creek Pump Station and Force Main. Witness Becker reiterated that the Amended Purchase Agreement was executed in 2002, that much of the Heater management team subsequently left the Company in early 2005, and that the first developer contract entered into pursuant to the Amended Purchase Agreement was not executed until 2006. Witness Becker admitted that, as a result of these changes and an oversight during the transition in management, Aqua NC failed to collect a pro rata portion of the capacity fees from developers between 2006 and 2018, resulting in approximately $315,000 of uncollected CIAC. Witness Becker contended that, with the benefit of hindsight and after numerous filings and proceedings in which these issues conceivably could have been raised, the Public Staff now is seeking what amounts to a $315,000 write-off of rate base and penalty to Aqua NC. Tr. Vol. 14, pp. 24-25.

[1] Through June 2018, Aqua NC failed to collect wastewater capacity payments from 1,432.27 SFREs (1432.27 SFREs x $220.41 per SFRE = $315,687).

In a late-filed exhibit,[1] the Public Staff stated that the Amended Purchase Agreement and a secondary developer contract were filed with the Commission on February 7, 2006, and approved[2] by the Commission in Docket No. W-218, Sub 538, by Order dated April 6, 2006.

Discussion and Conclusions

The Commission concludes that the Company did not act prudently or reasonably when it failed to collect CIAC to which it was contractually entitled in the amount of $315,687, for the construction of the Buffalo Creek Pump Station and Force Main. The Bulk Wastewater Agreement was approved by the Commission in 2002, prior to Aqua NC's acquisition of Heater. However, in the Company's Notification of Contiguous Extension filed on February 7, 2016, in Docket No. W-274, Sub 538, Aqua NC's management attached as an exhibit the Amended Purchase Agreement, which outlined Aqua NC's right to collect from developers sufficient CIAC for the construction of the Buffalo Creek Pump Station and Force Main. Similarly, the Amended Purchase Agreement was approved by Commission Order dated April 6, 2006, and Aqua was required to comply with the terms of all other Commission-approved contracts referenced herein.[3] In addition, an internal Heater memo dated August 6, 2004, clearly set forth Heater's understanding that 50% of the cost of the Buffalo Creek Pump Station and Force Main was to be collected from the secondary developers, pertaining to the first 2,000 SFREs. The amount of capacity fees as CIAC that should have been, but was not, collected by Aqua NC for the construction of the Buffalo Creek Pump Station and Force Main is not in dispute by the parties in this proceeding.

The Commission gives weight to Aqua NC's admission that it failed to include the appropriate contractual language in its contracts with secondary developers executed between 2006 and 2018. Likewise, Aqua NC does not dispute that it failed to collect CIAC in the amount of $315,687, as a result of Company management's "oversight." Tr. Vol. 14, pp. 24-25. The Commission also gives weight to Aqua NC witness Becker's admission on cross-examination, for which the Commission applauds Aqua NC for its accountability on this issue, that documentation exists demonstrating Aqua NC's intent to collect from the master developer of the Flowers Plantation the agreed-upon capacity fees as CIAC on a going-forward basis, but that Aqua NC's management failed to follow through on this. Failure of Aqua NC's management to review appropriately the contracts and other documentation addressing the utility's responsibilities and obligations undertaken by the prior owner with respect to Flowers Plantation provides insufficient excuse for failing to collect the contracted-for CIAC.

[1] On October 11, 2018, and as corrected on October 15, 2018, the Public Staff entered into the record its Late-Filed Exhibit Relating to the Flowers Plantation Contributions In Aid of Construction Issues.

[2] Ordering Paragraph 5 of the Commission's Order Recognizing Contiguous Extension and Approving Rates states "[t]hat Heater's agreements with developer, Walker Woods Development, LLC, and the developer River Dell Utilities, Inc., and River Dell Company, are hereby approved."

[3] Despite said contracts being filed with the Commission and subject to review by the Public Staff, the capacity fee Aqua NC charged to developers for the Flowers Plantation lots were neither included in Aqua NC's filed tariff, nor raised as a contested issue in any of Aqua NC's prior general rate cases or its numerous filings of contiguous extension notifications.

While the Commission agrees with Aqua NC that one contributing factor to this "oversight" could have been the fact that the pertinent capacity fees to be collected as CIAC for the Buffalo Creek Pump Station and Force Main should have been, but were not, included on the Company's tariff, the Commission is unpersuaded that this fact somehow excuses Aqua NC's responsibility to prudently manage the various contractual obligations and rights it assumed, and over which it subsequently had control, after it acquired Heater in 2004. On the other hand, Commission Orders in prior Aqua NC general rate cases have included the costs of the Buffalo Creek Pump Station and Force Main in rate base without offsetting CIAC that Aqua NC failed to collect. It is the Company's obligation to include in its filings and its rate case proceedings information concerning its ability to collect CIAC to help finance utility plant; it is not the Commission's obligation to guess about such matters. The Commission also depends on the Public Staff, as the agency responsible for investigating and auditing Aqua NC's books, to make timely recommendations with respect to cost-of-service adjustments. The contractual provisions at issue here were available for inspection and review prior to the instant case and more appropriately should have been brought to the Commission's attention in a timelier manner.[1] With that said, however, the Commission finds unpersuasive Aqua NC's contention that subsequent Commission approval of a secondary developer contract that lacked certain language pertaining to Aqua NC's right to collect capacity fees as CIAC somehow superseded the controlling terms of the 2002 Amended Purchase Agreement and Bulk Wastewater Agreement. Furthermore, upon Commission approval of the controlling Amended Purchase Agreement and Bulk Wastewater Agreement, the Commission had no reason, until the instant proceeding, to suspect that Aqua NC would not appropriately enforce the rights and obligations it was afforded pursuant to such contracts. It was Aqua NC's sole responsibility, not the responsibility of the Public Staff or of the Commission, to ensure that appropriate wording would be appropriately carried forward to future secondary contracts with developers.

For these reasons, the Commission will limit its disallowance of CIAC to that which Aqua NC failed to collect after its last rate case test year period, ending October 31, 2013, in Docket No. W-218, Sub 363. The Commission, therefore, concludes that it was not reasonable or prudent for Aqua NC's management to fail to collect sufficient CIAC to which it was entitled, in the amount of $218,999 (reflecting the amount of CIAC that the Company failed to collect subsequent to the updated cutoff date in its last rate case of October 31, 2013), for the construction costs of the Buffalo Creek Pump Station and Force Main.

The Commission further notes that Aqua NC witness Becker indicated that the Company will review the lots to determine if additional CIAC can be collected by addressing the capacity fee issue in its future contracts with secondary developers. If Aqua NC is able to collect additional capacity fees as CIAC for the construction of the Buffalo Creek Pump Station and Force Main,

[1] With respect to future proceedings to review applications for Certificates of Public Convenience and Necessity and/or notifications of contiguous extensions filed with the Commission pursuant to Commission Rule R7-38, the Commission expects that, going forward, the Public Staff will audit and more closely scrutinize water and sewer contracts governing capacity and/or connection fees between the developer, the utility, and/or any third party from whom wastewater capacity is purchased. In the future, the Public Staff shall, for all such water utility contracts (not only those to which Aqua is a party), more closely investigate developer contracts before recommending the approval of such contracts to the Commission. Likewise, the Commission also expects the applicant (utility) to disclose and account for CIAC available from third parties.

Aqua NC may request that the Commission reevaluate this issue in a future proceeding based upon what Aqua NC may be able to collect in the future from lots other than the first 2,000 SFREs (i.e., Aqua NC could, in theory, and assuming it is able to now collect these fees pursuant to future contracts executed with secondary developers, request that the imputed CIAC in this proceeding become actual cash CIAC collected prior to the Company's next general rate case).

Aqua NC's Payment to Johnston County for 250,000 gpd of Wastewater Capacity

Company witness Becker testified that the Flowers Plantation development is expected to grow by approximately 300 lots per year. Based on this anticipated growth, the Company in 2017 began reviewing its capacity needs for Buffalo Creek based on actual flows. While considering plans to expand the Neuse Colony WWTP, the Company decided to examine the option of purchasing (reserving) wastewater treatment capacity from Johnston County (the County). The Company's option to purchase (reserve) wastewater capacity from the County expires in 2022. For these reasons, the Company determined that the prudent approach was to begin acquiring (reserving) and using capacity from the County before such time as Aqua NC's option to purchase capacity from the County expires.

In a Bulk Wastewater Service Agreement executed on May 14, 2002, Heater and Johnston County agreed that at some future date (possibly after Heater built out its 750,000 gpd Neuse Colony WWTP), Heater would purchase (reserve) bulk wastewater from the County and pay the County's then-prevailing capacity fee. The Bulk Wastewater Service Agreement further provided that the County's then-current capacity fee was \$5.50 per gpd, which would be adjusted by Johnston County in the future, based on the County's cost of construction of its WWTP.

According to witness Becker's testimony, in 2009, Johnston County quoted a price of \$6.29 per gpd for capacity, which included \$4.83 per gpd for wastewater treatment capacity and \$1.46 per gpd for transmission fees to upgrade the County collection system. The Company did not consider this to be a prevailing rate as referred to in the 2002 Bulk Wastewater Service Agreement, but rather to be an initial price quote. Aqua NC reached this conclusion because Johnston County does not have published (prevailing) rates for wastewater capacity, but rather states in its guidelines that wastewater capacity fees are determined on a negotiated basis.

In 2018, Johnston County quoted a rate of \$8.48 per gpd to Aqua NC, which included a \$5.34 gpd charge for wastewater treatment capacity and \$3.14 per gpd for transmission fees to upgrade the County's collection system.[1] Aqua NC decided to begin the process of purchasing (reserving) capacity from the County in 2018, and consequently paid the \$8.48 per gpd rate.

Because Aqua NC had been collecting \$6.00 per gpd in CIAC from most developers, the Company concluded that it had appropriately charged and received sufficient funding to purchase (reserve) the 250,000 gpd of wastewater capacity from the County in 2018. The Company viewed the \$5.34 per gpd capacity charge to be reasonable, but not the \$3.14 per gpd transmission fee,

[1] This fee does not reimburse the County for the interconnection facilities between Aqua NC's Neuse Colony WWTP and the County's collection system. Aqua incurs these costs. However, the interconnection point is to the County's collection system, not directly into the County's WWTP. The \$3.14 per gpd is a fee the County assesses generically to those connecting to its transmission and connection system.

because the initial contract provided that the capacity fee could be adjusted based only on the cost of construction for the County's WWTP and it was the Company's understanding that Johnston County's WWTP had not been upgraded since 2006.

Company witness Becker stated that Aqua NC engaged the Public Staff to proactively discuss the purchase of Johnston County wastewater capacity to serve Buffalo Creek. Tr. Vol. 5, p. 39. On June 21, 2018, Aqua NC purchased 250,000 gpd of wastewater treatment capacity from Johnston County for $2,120,000.

On cross-examination by the Public Staff on September 24, 2018, witness Becker stated and then reaffirmed that Aqua NC has received the necessary engineering approvals from DEQ to construct the interconnection to the Johnston County wastewater system. Tr. Vol. 15, p. 54.

Witness Junis cited Paragraph 7.I. of the Amended Purchase Agreement, which provides, in pertinent part, that "Secondary Developer shall pay to Heater a cash contribution in aid of construction the same dollar amount per gallon as the County's then current bulk wastewater capacity fee, which at the time of the execution of this Amended Agreement is $5.50 per gallon." Ex. Vol. 12, p. 141.

Witness Junis testified that Aqua NC sold (reserved) approximately 333,671 gpd of wastewater capacity to Buffalo Creek developers. He further testified that Aqua NC charged developers CIAC in the amount of $5.50 per gpd in 2006, which was the first time the Company sold (reserved) wastewater capacity to serve Buffalo Creek. Witness Junis testified that Aqua NC subsequently charged Buffalo Creek developers CIAC in the amount of $6.00 per gpd. Witness Junis asserted that the wastewater capacity fee to be paid to the County is a negotiated rate that was provided by Johnston County to Aqua NC on at least four occasions – in 2002, in 2009, and twice in 2018. Ex. Vol. 12, p. 146.

In support of the Public Staff's position, witness Junis testified that Aqua NC collected $1,497,400 for 250,000 gpd of wastewater capacity between January 11, 2006, and November 10, 2017. Tr. Vol. 12, p. 148. He testified that, in his opinion, the capital cost of $2.120 million for the wastewater capacity purchased from Johnston County and associated CIAC of $1.497 million should be removed from rate base. Tr. Vol. 12, pp. 148-150. Witness Junis asserted that Aqua NC could have avoided creating rate base if it (1) had better tracked the quantities of capacity being sold (reserved) to developers on each side of the Flowers Plantation development; (2) better matched the CIAC to be collected with Johnston County's then-current capacity rate; and (3) incrementally purchased (reserved) capacity from Johnston County as it received the associated CIAC from developers. Tr. Vol. 12, pp. 151-152.

Witness Junis asserted that the wastewater capacity purchased (reserved) by Aqua NC from Johnston County is not used and useful, as Aqua NC has not yet interconnected to Johnston County's wastewater collection system.

The Public Staff in its late-filed exhibit confirmed that the Agreement was filed with the Commission and approved by Commission Order in Docket No. W-274, Sub 392.[1] The Agreement was not found to be filed in any other dockets.

In rebuttal, witness Becker again testified that the capacity that witness Junis contends that the Company should have been purchasing (reserving) over the last decade was not needed throughout that time, and, therefore, it would have been imprudent for the Company to purchase (reserve) additional capacity before it was needed.[2] For that reason, witness Becker argued that it would be inappropriate for the Commission to impute $622,500 of CIAC, as recommended by the Public Staff, because Aqua NC acted prudently in not purchasing (reserving) unneeded capacity over the past 12-year period.

Witness Becker testified that it is appropriate to include these costs in rate base because the capacity will be used and useful within a reasonable time frame after the close of the evidentiary hearing. He stated that he has been advised that North Carolina courts have held that customers could be assessed costs for future customers when the costs were based on a short-term projection. For these reasons, witness Becker argued that it is appropriate to include this purchase in rate base, or, in the alternative, to allow the Company to create an asset held for future use and recover carrying charges on the amount of the purchase. As a second alternative, witness Becker argued that both the purchased capacity asset and the entire amount of CIAC collected toward same should be removed as offsetting rate base assets.

Company witness Becker testified that, based on the rapid growth rate of the Flowers Plantation development and the 2022 sunset clause on Aqua NC's option to purchase wastewater capacity from Johnston County, Aqua NC determined that it needed the capacity and purchased 250,000 gpd of capacity for $8.48 per gpd. He explained that "Aqua decided to purchase as much capacity as could be purchased using the CIAC received from Buffalo Creek developments of $2,000,925" for 333,671 gpd. Tr. Vol. 14, p. 30.

Witness Becker asserted that the Amended Purchase Agreement does not explain how the $5.50 per gpd capacity fee was determined or how it is defined. He added that the capacity fee to be paid to Johnston County "shall be adjusted in the future based on the County's cost of construction of the County's wastewater treatment plant," and to the Company's knowledge, there has been no construction of the Johnston County wastewater treatment plant since 2006.

[1] Ordering Paragraph 5 of the Commission's Order Granting Franchise and Approving Rates states "[t]hat Heater's agreement with Johnston County and the developer, Rebecca Flowers, d/b/a River Dell Company, is hereby approved."

[2] Aqua NC had concerns that if the payment to Johnston County was made to reserve wastewater capacity prior to the time the actual capacity was needed, the Company would not receive rate base treatment on the asset (capacity purchased from Johnston County). On p. 20 of Aqua NC witness Becker's rebuttal testimony, he states that "the premature purchase of unneeded capacity from Johnston County benefits only [Johnston] County..." Tr. Vol. 14, p. 28. The Commission agrees with Aqua NC that it was prudent to wait to reserve capacity from the County until needed and that construction of Aqua NC's interconnection to the County should appropriately coincide with the need for the capacity. The Commission rejects inclusion of the costs of capacity payments as not yet used and useful. Had Aqua NC adhered to the Public Staff's view that the Company reserve capacity concurrently with receipt of CIAC from Buffalo Creek developers, Aqua NC for years unwisely would have expanded rate base funds ineligible to include in cost of service because not used and useful.

Tr. Vol. 14, p. 27. Witness Becker testified that, with the advantage of hindsight, Public Staff witness Junis effectively proposes to impute money (the shortage of approximately $2.49 gpd) that Aqua NC did not collect from developers as CIAC. Id. at 30-31.

Witness Becker disagreed with witness Junis' proposed adjustment to remove from Plant in Service the wastewater capacity fee of $2.120 million that Aqua NC paid to Johnston County in 2018. He stated that witness Junis does not recommend removing a corresponding amount of CIAC, but instead recommends removing only $1.497 million of CIAC. Tr. Vol. 14, p. 34. Witness Becker did not dispute that the Company "only collected an average of $5.99 per gpd from developers over the past 12 years for the first 250,000 gallons" of wastewater capacity for Buffalo Creek. Tr. Vol. 14, p. 31.

Witness Becker stated that the Bulk Wastewater Service Agreement was filed with the Commission in Docket No. W-274, Sub 392. He further stated that, had the provisions for recovery of capacity fees to be collected from developers and paid to the County been included in Heater's tariff, then it would have been less likely that these provisions "would have been overlooked." Tr. Vol. 14, p. 32. Witness Becker testified that "[t]he Commission's Orders are important, and they are relied upon by investors." Tr. Vol. 14, pp. 32-33.

Witness Becker testified that the purchased wastewater capacity from Johnston County will be used and useful within a reasonable amount of time after the test period, and, therefore, it would be appropriate to include the full amount in rate base. Alternatively, witness Becker asserted that, at the very least, the Company should be allowed to create an asset held for future use and recover carrying charges on the amount of the 250,000 gpd capacity purchase from Johnston County. Tr. Vol. 14, p. 35.

Discussion and Conclusions

The Commission has carefully reviewed the evidence and contentions of the parties on the issue of reservation and transmission fees paid to Johnston County and the reservation fees collected from Flowers Plantation developers.

As a preliminary matter, throughout the litigation of this rate case, both Aqua NC and the Public Staff have consistently treated the capacity payment to Johnston County as an asset accounted for in the same account Aqua NC uses for its Plant in Service. The Commission relies on this specific accounting classification, which was uncontested by any party to this rate case, in deciding the disputed issues related to Johnston County. In so doing, the Commission does not make any determinations as to the appropriateness or accuracy, for ratemaking purposes, of the non-dispositive accounting classifications and/or treatment of the capacity payment to Johnston County as an asset in Aqua NC's Plant in Service account.

In deciding these issues, the Commission highlights that there were several different ways it could have decided the myriad complex issues presented by the circumstances comprising the Johnston County and Flowers Plantation facts. Indeed, the parties litigated these issues zealously, but the Commission is not persuaded that any of the outcomes suggested by the parties as they pertain to these issues are (1) correct as a matter of law; or (2) preferable over the ratemaking discretion exercised by the Commission in determining these issues in the manner set forth herein.

In this case, no party has questioned whether the costs to purchase capacity from Johnston County are "known and measurable"; indeed, the Company documented these costs and has shown that they were in fact incurred. Rather, the arguments raised by the Public Staff challenging the inclusion of the Company's Johnston County capacity costs in rates hinge on whether those costs are "reasonable and prudent" and whether they are "used and useful."

The Commission notes that the published Johnston County Water and Sewer Policies do not establish a prevailing rate for wastewater treatment capacity but rather provide for a negotiated fee based on gpd of average flow based on the cost of infrastructure improvements. Furthermore, the County's capacity fee was to be adjusted in the future based on the County's cost to construct its WWTP. A negotiated fee contemplates some interaction between the parties and envisions that a mutual decision will be reached. The record is clear that no such qualifying upgrades have been made by the County to its WWTP since 2006.

The Commission further notes that it is possible that Johnston County, sometime after the execution of the May 14, 2002 Agreement, changed its policy such that increases in its prevailing capacity fee would be negotiated based on costs of infrastructure improvements, including those made to its collection system, and would not be based upon the cost of construction of its WWTP. However, even if such policy changes were made, they do not negate or otherwise supersede the contractual obligations accepted by Johnston County in the May 14, 2002 Agreement. An analysis of the rate proposals offered by the County in 2009 and 2018 must be reconciled with the provisions of the May 14, 2002 Agreement, which clearly contemplate that the capacity fee and the charges for transmission and treatment services are separate and distinct. The 2009 letter from Johnston County to the then-President of Aqua NC distinguishes the $4.83 per gpd capacity cost as being based on the unit capital cost of the County's most recent WWTP facilities expansion, which is consistent with the original Agreement. The $1.46 per gpd transmission cost was stated as another charge, separate and distinct from the capacity charge, and is not related to treatment as specifically referenced by the Agreement.

A review of the July 18, 2018 letter from Johnston County to witness Becker leads to a similar conclusion. Although the total fee proposal was $8.48 per gpd, it was separated into a proposed capacity fee of $5.34 per gpd for WWTP capacity based on the cost of the last expansion, which occurred in 2006, again consistent with the intent of the May 14, 2002 Agreement. The email from Johnston County to the Company on August 23, 2018, supports this interpretation. Accordingly, the Commission concludes that the Company's contention that the rate quoted by the County in 2018 included a capacity fee of $5.34 per gpd for capacity and a separate charge of $3.14 per gpd for transmission is reasonable.

The Public Staff alleges that it was unreasonable for the Company not to purchase capacity from the County over time or to adjust the amount of CIAC charged to developers based on the rates provided by Johnston County over time. However, to accept this argument, the Commission must ignore the existing contractual provision that the capacity charge and the transmission charge are separate and distinct charges, which is a position that the Commission does not accept. Even if the May 14, 2002 Agreement were subject to a different interpretation, the Commission is unable to conclude that Aqua NC's interpretation is unreasonable, and further notes that the Company's interpretation of the contract has remained consistent since 2002. Furthermore, the Commission notes that the 2002 Agreement is ambiguous or silent about several material issues now disputed in the instant proceeding, including whether the capacity would be reserved in small increments, when the capacity would be reserved, and the timing of when such reservation payments would be owed by Aqua NC.[1] The Agreement also states, "Heater shall pay to the County the County's then prevailing capacity fee for bulk wastewater. The current fee is $5.50 per gpd, which shall be adjusted by the County in the future, based on the County's cost of construction of the County's wastewater treatment plant."

The final capacity fee was clearly the result of a negotiated rate. Therefore, the Commission concludes that it would have been unreasonable for Aqua NC to ignore the contractual provisions that offered financial protection to the Company and its ratepayers by raising the $6.00 per gpd charge to secondary developers to match what amounted to mere offers received from Johnston County. Similarly, it would have been unreasonable for Aqua NC to purchase capacity on a piecemeal basis when the Company did not yet have a need for the capacity. Further, the approximate $6.00 per gpd CIAC capacity charge has been subject to review by both the Public Staff and the Commission in numerous rate cases and filings for contiguous extensions involving Aqua NC, of which the Commission takes judicial notice.

Reservation fees the Company pays to Johnston County should reduce the County's fixed costs recovered through the County's rates. As previously discussed herein, Aqua NC's payments to the County are to be negotiated. Aqua NC, therefore, should stress to the County that these reservation fee prepayments reduce the County's fixed costs, and thus should be reflected in a reduced capacity charge that Aqua NC pays to the County.

The Commission concludes that Aqua NC paid Johnston County $1,335,000, or $5.34 per gpd, to reserve the 250,000 gpd of capacity in the test year in this rate case. The Commission also concludes that Aqua NC paid Johnston County $785,000, or $3.14 per gpd, during the test year to defray the County's maintenance, upkeep, and potential extension of the County's transmission and distribution system. The Commission, in its discretion, concludes that it is reasonable and appropriate to treat the $785,000 differently from the $1,335,000.

The Commission concludes that the $1,335,000 should not be added to Aqua NC's rate base at this time because Aqua NC's interconnection to the County's transmission and distribution system was not completed as of the end of the test year, as extended to the close of the hearing, and thus, Aqua NC could not make use of its Johnston County capacity payment to serve customers at that time. Likewise, the Commission is not convinced that Aqua NC's interconnection to the County's transmission and distribution system will occur within a reasonable time period after the close of the test year in this case. Under the statute, Aqua NC's capacity payment to Johnston

[1] One such example of the contract's ambiguous nature includes that reservation payments "shall be paid for by Heater as Heater takes down the capacity." Ex. Vol. 12, p. 328.

County, therefore, is not used and useful. This finding is consistent with North Carolina case law holding that current customers should not have to pay for plant costs related to future customers.[1]

In so determining, the Commission relies on the Company's late-filed exhibits of October 3, 2018, which included a cover letter stating, in pertinent part, that "the permit for the construction of Aqua NC's wastewater collection system extension" interconnecting the Neuse Colony WWTP and Johnston County's collection Force Main was issued on September 28, 2018 (four days after witness Becker's testimony that Aqua NC had already received the necessary regulatory approval to construct the interconnection).[2] While not specifically requested by the Commission, yet informative, the Company provided a letter from witness Pearce in response to a request for information from DEQ that stated that "[i]t is currently estimated that the engineering plan submittal for the Pump Station will be submitted to DEQ before August 15, 2018 and for the interconnect construction to be completed by March 31, 2019." [3] However, Aqua NC did not submit a request to DEQ for an Authorization to Construct until September 4, 2018.[4] It similarly did not file with the Commission an application for the Wastewater Collection System Extension Permit until September 4, 2018, supplementing its application with additional information on September 11, 2018. The aforementioned submittals were provided by Aqua NC at minimum 20 days later than previously estimated by the Company. The Commission gives weight to the discrepancy between the expected and actual dates of these submittals as evidence of uncertainty as to the estimated completion date of March 31, 2019 (the last day of the first quarter of 2019), for the interconnection between the Neuse Colony WWTP and Johnston County's collection Force Main.

The Commission further notes, however, that the prototypical "used and useful" analysis does not apply neatly to these Aqua NC capacity reservation fees. Aqua NC will not use the capacity reserved from Johnston County to serve customers for some time after Aqua NC's interconnection to the County's system. Instead, Aqua NC needs the capacity to enable developers of lots within the Flowers Plantation to receive necessary development approvals and, ultimately, complete buildout. In this respect, timing of the interconnection is far less significant than placing on-line utility plant needed immediately or in the near term to serve load. With the County's commitment, Aqua NC can accommodate developers' needs now, even though Aqua NC's interconnection to the County's system is not yet complete. This arguably could have led the Commission to a different conclusion on the "used and useful" dispute, and is one factor relied

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[1] See N.C.G.S. § 62-133(b)(1); see, e.g., State ex rel. Utils. Comm'n v. Carolina Water Service, Inc., 328 N.C. 299, 401 S.E.2d 353 (1991); State ex rel. Utils. Comm'n v. Public Staff-North Carolina Utils. Comm'n, 333 N.C. 195, 424 S.E.2d 133 (1993).

[2] The Wastewater Collection System Extension Permit was entered into the record as Aqua NC Johnston County Late-Filed Exhibit 3.

[3] The letter was entered into the record as Aqua NC Johnston County Late-Filed Exhibit 1.

[4] The Authorization to Construct was entered into the record as Aqua NC Johnston County Late-Filed Exhibit 2.

upon by the Commission to treat the reservation fees as capacity payments, and, thus, differently from the transmission charge.

As discussed above, the Commission determines it unwise and inappropriate to match developer capacity reservation fees that Aqua NC assesses in Flowers Plantation with any particular asset. This determination is particularly appropriate where, as is the case here, the asset is considered Plant in Service and the capacity made available under such agreement will be available to Aqua NC for use throughout Flowers Plantation. Consequently, the Commission rejects treatment that would disallow as an offset to rate base any CIAC Aqua NC collected through the end of the hearing with respect to any property being developed within Flowers Plantation. On a related note, there would be no rate base effect if the capacity purchased from Johnston County and the CIAC of equal amounts were both included in rate base; the converse also is true – there would be no rate base effect if the capacity purchased from Johnston County and the CIAC of equal amounts were both excluded from rate base. It seems clear that the intent of the parties, as memorialized in the contracts at issue here,[1] was to effectuate these transactions in a rate base-neutral and revenue-neutral manner (the developers pay Aqua NC, and then Aqua NC pays Johnston County), where feasible.[2] The Commission further notes that Aqua NC's ratepayers have benefitted over the years from the inclusion in rate base of CIAC subsequently used to purchase capacity from the County. The Commission, on balance and in exercising its discretion, endeavors to decide these issues in a manner that is both in the public interest (here, meaning rate base-neutral), and is consistent with the intent of the underlying contract.

Because Aqua NC's payments to Johnston County constitute a situation with a unique set of facts, the Commission determines to treat the $785,000 payment differently. While there are different ways that this test year payment might be appropriately treated, for ratemaking purposes, the Commission determines that the $785,000 payment should be treated as an expense on the income statement. As best the Commission can determine based on the state of the record before it, the County collects this fee to maintain, repair, and potentially expand its transmission and distribution system. It is not used to defray the costs of building or expanding the County's WWTP, at least to the extent that no such upgrades to the County's WWTP have occurred since 2006, when Aqua NC first began collecting CIAC toward its eventual capacity purchase from the County. Tr. Vol. 14, p. 27. Aqua NC will connect its transmission line from the Neuse Colony WWTP at a point on the County's collection system, not at the County's WWTP itself.

While the Commission determines to treat the $785,000 transmission fee as an expense, it further concludes, in its discretion, that this expense should not be recognized entirely in one cost of service year, but instead should be amortized and recovered over six years with no unamortized balance in rate base. Accordingly, $130,833 should be expensed in this case. This amortization

[1] This intent also is evidenced in the letter then-President of Aqua NC, Tom Roberts, wrote in April 2015, and in Ruffin Poole's e-mail of October 2013.

[2] In calculating the revenue requirement impact of the exclusion from plant in service of the $1,335,000 capacity payment to the County, the Commission uses a 2.00% depreciation rate and a useful life of 50 years.

period, in the Commission's discretion, appropriately balances the interests between Aqua NC and its ratepayers.

The Commission recognizes that there is additional CIAC yet to be collected by Aqua NC from developers as the Flowers Plantation continues to expand. In so recognizing, the Commission directs Aqua NC to charge, in all future contracts executed with Flowers Plantation developers, a reservation fee of at least $8.48 per gpd, unless and until such time as Aqua receives written communication from the County informing Aqua NC that it has changed the $8.48 per gpd rate, inclusive of the transmission and distribution expense charge, at which point the modified rate controls. The Commission further directs Aqua NC to obtain such written documentation of the current capacity fees charged by Johnston County on at least an annual basis until such time as Aqua NC's option to reserve capacity from the County expires. Finally, the Commission directs Aqua NC to use, going forward, accounting treatment and classifications for rate base purposes in a manner consistent with the treatment afforded by this Order.

Aqua NC's Request for Deferral Accounting Treatment of Purchased Capacity

Having already determined that the Company has failed to show that the capacity purchased from Johnston County is used and useful Plant in Service to Aqua NC's ratepayers as of the end of the test period in this case, or will be used and useful within a reasonable time thereafter, the Commission finds premature, and thus, moot, the Company's request, made in the alternative, to allow deferral accounting through the establishment of a regulatory asset for the Johnston County capacity costs. Therefore, the Commission concludes that the Company's request in the alternative to allow deferral accounting treatment for the capacity it purchased from the County should be denied.

ADIT

The difference in the level of ADIT is due to the differing levels of unamortized rate case expense, post-test year plant additions, unamortized repair tax credit, and EDIT recommended by the Company and the Public Staff. Based on the conclusions reached elsewhere in the Order, the Commission concludes that the appropriate level of ADIT for use in this proceeding is $24,849,085.

Summary Conclusion

Based on the foregoing, the Commission concludes that the appropriate level of rate base for combined operations for use in this proceeding is as follows:

Item	Amount
Plant in Service	$492,295,394
Accumulated depreciation	(155,246,692)
Contributions in aid of const.	(196,384,493)
Accum. amortization of CIAC	70,758,708
Acquisition adjustments	2,055,735
Accum. amort. of acquis. adj.	1,040,444

Advances for construction	(4,467,841)
Net Plant in Service	210,051,255
Customer deposits	(379,445)
Unclaimed refunds	(193,255)
Accum. deferred income taxes	(24,849,085)
Materials and supplies inventory	2,405,967
Excess capacity adjustment	(1,322,276)
Working capital allowance	4,759,698
Original cost rate base	$190,472,859

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 53-58

The evidence supporting these findings of fact is contained in the Application and in the testimony of Public Staff witnesses Cooper and Junis, and Company witness Gearhart. The following table summarizes the differences between the Company's level of operating revenues under present rates from its Application and the amounts recommended by the Public Staff:

Item	Company Application	Public Staff	Difference
Service revenues	$54,039,950	$55,496,957	$1,457,007
Late payment fees	113,213	114,830	1,617
Miscellaneous revenues	1,283,259	1,355,499	72,240
Uncollectibles & abatements	(404,234)	(414,248)	(10,014)
Total operating revenues	$55,032,188	$56,553,038	$1,520,850

With the Stipulation and the revisions made by the Public Staff in its supplemental testimony and Revised Supplemental Cooper Exhibit I, the Company does not dispute the following Public Staff adjustments to operating revenues under present rates:

Item	Amount
Reflect Company pro forma level of service revenues	$1,457,007
Adjustment to late payment fees	1,617
Adjustment to reclassify availability revenues	72,240
Adjustment to uncollectibles & abatements	(10,014)
Total	$1,520,850

Therefore, the Commission finds and concludes that the adjustments listed above, which are not contested, are appropriate adjustments to be made to operating revenues under present rates in this proceeding.

Summary Conclusion

Based on the foregoing, the Commission concludes that the appropriate level of operating revenues under present rates for combined operations for use in this proceeding is as follows:

WATER AND SEWER – RATE INCREASE

Item	Amount
Service revenues	$55,496,957
Late payment fees	114,830
Miscellaneous revenues	1,355,499
Uncollectibles & abatements	(414,248)
Total operating revenues	$56,553,038

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 59-86

The evidence supporting these findings of fact is contained in the Application and Aqua NC's NCUC Form W-1 filing, the testimony of Public Staff witnesses Cooper, Henry, Boswell, Feasel, Junis, and Darden, and Company witnesses Gearhart, Becker, Kopas, Pearce, and Berger.

The following table summarizes the differences between the Company's level of O&M and G&A expenses from its Application and the amounts recommended by the Public Staff:

Item	Company Application	Public Staff	Difference
Salaries and wages	$10,582,933	$10,048,145	($534,788)
Employee pensions and benefits	3,307,897	3,021,650	(286,247)
Purchased water/sewer	2,390,335	2,316,616	(73,719)
Sludge removal	536,333	559,382	23,049
Purchased power	3,660,633	3,570,667	(89,966)
Fuel for power production	26,809	26,809	0
Chemicals	1,403,799	1,521,967	118,168
Materials and supplies	505,720	505,720	0
Testing fees	971,148	902,172	(68,976)
Transportation	919,149	919,149	0
Contractual services – eng.	2,750	2,750	0
Contractual services – acctg.	188,101	188,101	0
Contractual services - legal	263,190	196,144	(67,046)
Contractual services - other	4,258,718	4,199,984	(58,734)
Rent	309,942	309,942	0
Insurance	963,266	650,674	(312,592)
Regulatory commission expense	224,568	92,562	(132,006)
Miscellaneous expense	1,497,272	1,444,151	(53,121)
Interest on customer deposits	32,388	32,388	0
Annual. and consumption adj.	7,051	127,978	120,927
Total O&M and G&A expense	$32,052,002	$30,636,951	($1,415,051)

With the Stipulation and the revisions made by the Public Staff in the supplemental testimony and Revised Supplemental Cooper Exhibit I, the Company does not dispute the following Public Staff adjustments to O&M and G&A expenses:

WATER AND SEWER – RATE INCREASE

Item	Amount
Update salaries & wages through 6/30/18	($40,329)
Remove open positions	(174,436)
Adjustment to reflect actual overtime pay	(18,568)
Update pensions & benefits through 6/30/18	(36,587)
Remove benefits related to open positions	(149,986)
Adjustment to remove original pro forma allocated benefits	6,364
Remove duplicate Health Advocate benefits	(9,445)
Adjustment to insurance expense	(312,592)
Adjustment to communication initiative	13,989
Adjustment to remove legal invoices before test year	(12,942)
Adjustment for legal fees related to fines and penalties	(10,099)
Adjustment to purchased power	(89,966)
Adjustment to chemicals	118,168
Adjustment to contract services to remove pre-test yr. invoices	(1,366)
Adjustment to contract services for NC 811 locates	(57,368)
Remove legal fees related to legislation	(44,005)
Adjustment to payroll taxes	8,260
Total	($810,908)

Therefore, the Commission finds and concludes that the adjustments listed above, which are not contested, are appropriate adjustments to be made to the O&M and G&A expenses in this proceeding.

The Company disagrees with the following Public Staff adjustments to O&M and G&A expenses, as evidenced by the testimony of Company witnesses Gearhart, Becker, Kopas, Pearce, and Berger:

Item	Amount
Remove ½ of operators' salaries	($58,051)
Adjustment to remove 30% of bonuses	(29,648)
Adjustment to allocate 50% of executive compensation to shareholders	(213,756)
Remove ½ of four operators' benefits	(15,748)
Adjustment to allocate executive benefits to shareholders	(80,845)
Adjustment to board of directors fees	(67,110)
Annualization and consumption adjustment	120,927
Adjustment to sludge removal	23,049
Adjustment to testing	(68,976)
Adjustment to regulatory commission expense	(132,006)
Adjustment to purchased water	(73,719)
Total	($595,883)

These contested adjustments affect salaries and benefits, miscellaneous expense, sludge removal, testing, regulatory commission expense, and purchased water.

Salaries and Benefits

With the Stipulation and revisions made by the Public Staff in its supplemental testimony and Revised Supplemental Cooper Exhibit I, the Company does not dispute the following Public Staff adjustments to salaries and wages:

Item	Amount
Update through 6/30/18	$ (40,329)
Remove open positions	(174,436)
Actual overtime payroll	(18,568)
Total	$ (233,333)

Therefore, the Commission finds and concludes that the adjustments listed above, which are not contested, are appropriate adjustments to be made to salaries and wages in this proceeding.

Based on the testimony of Company witnesses Kopas, the Company disagrees with the following Public Staff adjustments to salaries and wages:

Item	Amount
Remove operators' salaries	$ (58,051)
Remove 30% of STI bonus	(29,648)
Remove 50% of executive compensation	(213,756)
Total	$ (301,455)

The difference in the level of employee pensions and benefits is due to the differing levels of salaries and wages recommended by the Company and the Public Staff. Based on the conclusions reached elsewhere in the Order regarding the levels of salaries and wages, the Commission concludes that the appropriate level of employee pension and benefits for use in this proceeding is $3,077,822.

The Public Staff and the Company disagree on the following items concerning salaries and benefits: (1) an adjustment to salaries and wages and related benefits that quantifies the expense savings as a result of USIC performing the One Call/NC 811 work previously performed by Aqua NC personnel; (2) an adjustment to remove 30% of employee bonuses that are related to earnings per share; and (3) an adjustment to allocate executive compensation and related benefits to shareholders.

Operators' Salaries and Benefits

In his direct testimony, Aqua NC witness Gearhart testified that the Company added a new contract in 2018 for USIC to perform One-Call/NC 811 responsibilities. Witness Gearhart explained that the amount included was based on estimated calculations and a pending contract with the contractor. He stated that, during discovery, the Company submitted the executed contract and the initial invoices received from USIC to the Public Staff. Tr. Vol. 5, p. 221.

Public Staff witness Junis testified that Aqua NC filed a pro forma adjustment to the Contract Services – Other expense in the amount of $507,880, which Public Staff witness Junis cited to Column (g) of Aqua NC's Application Exhibit B3-m, for USIC to perform utility locates and other activities in response to the NC 811 system. Tr. Vol. 12, p. 152.

Witness Junis described the Public Staff's recommended adjustment to normalize the annual expense to an amount of $450,511, based on actual locate tickets received during the months of May and June 2018, after USIC started to perform the responsibilities. Tr. Vol. 12, p. 153. The Company agreed to Public Staff witness Junis' proposed adjustment as part of the Stipulation.

Witness Junis testified that, in an effort to quantify the expense savings as a result of USIC performing the One Call/NC 811 work previously performed by Aqua NC personnel, the Public Staff made multiple data requests. See Junis Exhibit 21, EDR 33 Q2 and Junis Exhibit 22, EDR 45 Q1. Witness Junis testified that Aqua NC management originally planned to hire six full-time employees to fully perform the work the Company had been deficient in completing. The evaluation had excluded supervisor time necessary to conduct a cursory review and assign workable tickets in the Company's service territory. Witness Junis stated that Mr. Joe Pearce, Aqua NC's Director of Operations, estimated the expense that Aqua NC avoided by contracting USIC to be approximately $693,667, which includes the fully loaded costs of 10 field staff and one supervisor. Furthermore, the Company stated:

> Approximately 10% of 811 work orders are currently being worked...the remaining 90% are not being addressed timely. This delinquency has exposed ANC to fines/penalties, lawsuits, and significant repair costs necessary to fix damaged unmarked lines.

EDR 45 Q1, p. 1.

Based on an allegation of Aqua NC's inability to quantify the actual expense incurred in the test year to address One Call/NC 811 tickets, the responses referenced above, and the fact that the Company has stated approximately 40% of all the tickets were workable and only 10% of those were being completed, Public Staff witness Junis recommended reducing workforce expense for 50% of a Field Supervisor I's workload and 50% of three Utility Technicians' workload, one from each of the three regions, to complete tickets that the Company responded to prior to contracting with USIC.

In his rebuttal testimony, Aqua NC witness Becker testified that he disagreed with the Public Staff's proposed adjustment to reduce the Company's workforce labor and benefits expense by 50% for four positions, due to Aqua NC's decision to contract with USIC to do line locates. Witness Becker asserted that witness Junis seeks to arbitrarily eliminate part of Aqua NC's workforce, overriding a responsible management decision to redeploy employees to other tasks, due to management's decision to employ an outside vendor to comply with One Call/NC 811 work. According to witness Becker, witness Junis' adjustment is essentially the elimination of two full time employees (FTEs) and that adjustment should be summarily rejected as it: (a) reflects an unsupportable and inappropriate intrusion into management decisions; (b) ignores Aqua NC's demonstrated need and prerogative to contract with outside vendors for completion of a range of activities which are not the Company's core competencies, specifically including line locates; and (c) ignores the fact that there was no staff reduction, as staff time was reassigned to other core services.

Witness Becker further stated that Aqua NC began looking at the possibility of outsourcing the One Call/NC 811 work in 2017. During that year, the Company's operations management team made and supported a recommendation to outsource line locate work related to One Call/NC 811 requirements. The Company determined that these functions are more reasonably managed and handled by outside vendors who specialize in the activity. The contract with USIC was executed on February 26, 2018, and USIC began to handle Aqua NC's NC 811 call volume on May 1, 2018.

Company witness Becker testified that certain factors supported the Company's decision to rely on an outside vendor to meet this function. Specifically, witness Becker stated that management focused on the choices and the evaluation of alternatives, including hiring more FTEs to perform the work internally, and decided to outsource this activity based on the following factors:

(1) The skill set necessary to complete line locates is different than those of water and wastewater professionals;
(2) Using Aqua NC's water and wastewater professionals to complete the large volume of line locates is disruptive to their normal work schedules;
(3) This work is episodic and includes emergency locate requirements;
(4) It is an inefficient use of a water/wastewater supervisor's time to continuously manage this effort; and
(5) Using a firm with statewide coverage, specific expertise, and ongoing activity in Aqua NC's areas of operation provides efficiencies and assurance of consistency.

According to witness Becker, it was clear to Aqua NC management that use of outside, specialized resources was the most appropriate option. The decision to contract line locate work additionally included, but was not limited to, consideration of benefits of avoiding additional hires for line locates, elimination of the responsibility of managing a non-core service, and reduction of risk and liability related to unaddressed line locates. Time previously spent by Aqua NC employees to respond to line locate work orders is now used for other water and wastewater duties which are more directly in line with Aqua NC's core services. These services, the need for which is increasing over time, not decreasing, include maintenance on filters, pumps, lift stations, wastewater treatment plant equipment, and collection and distribution lines; reporting requirements; environmental regulatory compliance; flushing initiatives; sludge hauling; testing; "Close the Loop" initiatives; and meeting customer expectations.

Witness Becker argued that the Public Staff has not made or supported any claim in this case that Aqua NC is overstaffed. To the contrary, Aqua NC's field workforce and supervisors are fully utilized daily to handle their workload. Witness Junis' testimony does not state that Aqua NC has either an excessive field supervisory or field staff workforce. Moreover, prior to the Public Staff's filing of testimony in this rate case, witness Becker stated that he had never heard anyone from the Public Staff or any other regulatory agency state that Aqua NC is overstaffed for field personnel. Witness Becker asserted that he could confidently state that the Company's field staff employees are fully utilized. Further, he asserted that, to the contrary, the Public Staff has, on several occasions in public forums in the past year, stated that Aqua NC was significantly understaffed in some respects.

Witness Becker stated that Aqua NC's intent related to line locate work was and is to cost-effectively meet regulatory requirements and reduce the Company's risk of asset damage and liability.

Witness Becker further testified that he disagreed with witness Junis' assumption that an Aqua NC supervisor was spending half of his/her time managing the One Call/NC 811 process. He stated that such assumption was incorrect and that, in fact, the lack of a supervisor, or half of a supervisor, was one of the drivers for the need to outsource this program.

Witness Becker testified that he could not say at this time whether there will be repair savings by having reduced contract claims. However, he asserted that any attempt to meaningfully correlate use of outside vendors with a change in the repair cost experience is, at this point, sheer hypothesis and is definitely not known and measurable. Witness Becker observed that the program has just begun, results will be tracked and monitored, and those results will be available for a future audit. Witness Becker contended that the proposed reduction of the expenses for employees who are actually on payroll and fully deployed doing necessary work shows indifference on the part of the Public Staff to: (a) management's prerogative to make deployment decisions; (b) the reality of Aqua NC's need for the staff; and (c) the fact that this is an opportunity to retain and use existing staff for legitimate purposes, rather than having to hire new employees.

Witness Becker recommended that the Commission reject, as inappropriate and unwarranted, all recommendations associated with reduction in workforce due to Aqua NC's decision to contract with a professional, specialized outside vendor to perform line locate services. The amount of labor previously expended addressing line locates was minimal; however, all previous time spent by these Aqua NC field staff and supervisors related to the provision of line locate services was filled with work on other core water and wastewater services necessary for operations.

Further, witness Becker noted that it is essential to Aqua NC, as a regulated utility, that regulation observe the difference between proper regulatory oversight and an attempt to supplant management's obligation to prudently run the business. Witness Becker maintained that rejection of this adjustment and of the Public Staff's insufficient rationale is appropriate. He also stated that such action would provide needed guidance about the proper balance that should be struck between the regulator and the regulated, with respect to the responsibility to manage the business on a day-to-day basis.

Based upon the foregoing, the Commission agrees with Aqua NC's decision to contract with USIC in 2018 to perform its One Call/NC 811 line locate responsibilities. Further, the Commission agrees with and finds reasonable witness Becker's testimony which recites the five factors, as previously listed herein, which led the Company to retain USIC as an outside vendor to perform the required One Call/NC 811 line locates. The Commission acknowledges that the Public Staff did not challenge Aqua NC's decision in this regard.

The Commission gives significant weight to the testimony of witness Becker that time previously spent by Company employees to respond to line locate work orders can now be used for other water and wastewater duties which are more directly in line with Aqua NC's core services. In his testimony, witness Becker listed various core services, including maintenance on filters, pumps, lift stations, WWTP equipment, collection and distribution lines, reporting requirements, environmental regulatory compliance, flushing initiatives, sludge hauling, testing, "Close the Loop" initiatives, and meeting customer expectations. The Commission recognizes the necessity for Aqua NC employees to devote additional effort to customer service and water quality concerns expressed by customers as a result of the customer testimony and statements received in this proceeding. The Commission is of the opinion that such additional needed effort cannot be accomplished simultaneously with Aqua NC's reducing its current operations personnel. Further, witness Becker testified concerning several new initiatives the Company has recently implemented to improve its customer communications and overall quality of service. The Commission recognizes that such new initiatives would require additional time and effort to be expended by Aqua NC's existing employees. Consequently, for these reasons, the Commission finds and concludes that the Public Staff's proposed adjustment to exclude 50% of the updated labor costs and benefits of four Aqua NC field operational employees from the cost of service in this case is inappropriate.

__Employee Bonuses Related to Earnings per Share__

Public Staff witness Henry stated in his direct testimony that Aqua NC's Application included bonuses paid to North Carolina employees during the test year, including Short-Term Incentive (STI) bonuses and achievement awards. He testified that after examining Aqua NC's bonus policies, he found it appropriate to recommend an adjustment to remove 30% of the STI bonuses paid to the North Carolina employees. He further testified that according to Aqua NC's most recent policies for the STI Plan, 60% of the metric weight depended on financial while 50% of the 60% is directly related to Aqua America's earnings per share. Witness Henry testified that earnings per share directly benefit the shareholders' value instead of being for the ratepayers' benefit. He testified that, therefore, the Public Staff recommended an adjustment to remove 30% of the bonuses from expenses and allocate them to the Company's shareholders.

Henry Supplemental Exhibit 1, Schedule 2 Revised, line 6 as filed on September 13, 2018 shows the Public Staff's recommended adjustment to allocate to shareholders 30% of the North Carolina supervisors' bonuses related to Aqua America's earnings per share totaling $29,648. This is the same amount as presented in witness Henry's direct testimony.

Aqua NC witness Kopas testified on rebuttal that he disagreed with Public Staff witness Henry's adjustment to allocate 30% of bonuses paid to North Carolina supervisory employees to shareholders. Witness Kopas stated that, for the reasons set forth in his testimony regarding the Company's opposition to the Public Staff's accounting adjustment to executive compensation, the STI is part of the total compensation paid to attract and retain qualified supervisory employees at Aqua NC. He testified that this financial metric reinforces to employees that it is their responsibility to serve Aqua NC's customers in a prudent and efficient manner. He further testified that the Company's ability to provide reliable service to its customers is directly related to its financial viability and linking a portion of those employees' compensation to a financial target encourages employees to achieve customer-based objectives in a cost-efficient manner. Witness Kopas testified that the STI (or supervisory bonus) program for Aqua NC has been in place without any ratemaking adjustment having been proposed or made in the Company's last two rate case proceedings.

After reviewing all of the evidence presented, the Commission concludes that the Public Staff's proposed adjustment to exclude 30% of the bonuses paid to North Carolina supervisory employees in the amount of $29,648 from the cost of service in this case is unreasonable and inappropriate for the reasons testified to by Aqua NC witness Kopas.

First, the Commission gives substantial weight to Aqua NC witness Kopas' rebuttal testimony that Aqua NC's STI is part of the total compensation paid to attract and retain qualified supervisory employees who actually work for Aqua NC in North Carolina and directly provide service to customers in this State in a manner designed to ensure that those customers are served in a prudent and efficient manner.

Second, the Commission gives great weight to witness Kopas' testimony that linking a portion of the compensation of North Carolina supervisory personnel to a financial target, as is the case with the STI, clearly encourages those employees to achieve customer-based objectives in a cost-effective manner.

Third, the Commission gives little weight to Public Staff witness Henry's testimony, which emphasizes his earnings per share analysis as essentially benefiting only the Aqua America shareholders' value with no stated benefit to ratepayers. The Commission agrees with Aqua NC that employee compensation packages that include financial metrics appropriately incentivize individuals to achieve goals that support strong operations of a company that ultimately does benefit ratepayers.

Further, the Commission concludes that if it approved the Public Staff's position on this issue, it would send the wrong message to Aqua NC and its North Carolina-based supervisory personnel. The Public Staff does not propose to exclude any of the salaries or other benefits earned by Aqua NC's North Carolina supervisory personnel in this case, and the Commission finds no reasonable basis to exclude any portion of the STI program from the Company's cost of service in this proceeding. Also, the Commission notes that witness Kopas specified that there have been no similar ratemaking adjustments either proposed or made in Aqua NC's last two rate case proceedings.

Finally, although the Public Staff specified in its proposed order that the Commission should not discourage incentive pay for Aqua NC's North Carolina supervisors and that the incentive metrics should benefit Aqua NC's customers, the Commission does not find the examples provided by the Public Staff reasonable or appropriate. The examples are not specific enough to be adopted in this case. However, the Commission finds that Aqua NC should review its STI bonus plan and consider basing the 50% of the 60% financial weighting of its current bonus plan on a more customer-specific metric.

Accordingly, for the reasons set forth above, the Commission concludes that the Public Staff's proposed adjustment to allocate 30% of North Carolina supervisory employee STI bonuses in the amount of $29,648 to shareholders and thereby exclude those expenses from the cost of service in this case is inappropriate and unsupported by the facts in this case. Therefore, the Public Staff's proposed adjustment to exclude 30% of North Carolina supervisory employee bonuses from Aqua NC's cost of service in this proceeding is hereby denied.

__Executive Compensation and Benefits Related to Shareholders__

Public Staff witness Henry testified that the Public Staff has proposed an adjustment to remove 50% of the compensation, including pension and incentive plans, of the top five executive officers of Aqua America as listed in the 2017 Annual Meeting of Shareholders Proxy Statement from Aqua NC's cost of service in this proceeding. He testified that Aqua America is the second largest investor owned water and wastewater utility in the United States with its shares traded on the New York Stock Exchange (NYSE) having a $6.709 billion market capitalization at the August 17, 2018, market close as reported by Morningstar. He further testified that Aqua America's market capitalization is larger than the cumulative market capitalization of $6.297 billion of the next four largest investor-owned water utilities which are American States Water Co. (NYSE), California Water Service Group (NYSE), SJW Group (NYSE), and Connecticut Water Service, Inc. (NASDAQ).

Witness Henry testified that the five executives identified by the Public Staff are: (1) the President and Chief Executive Officer; (2) the Executive Vice President and Chief Financial Officer; (3) the Executive Vice President and Chief Operating Officer; (4) the Executive Vice President, Strategy and Corporate Development; and (5) the Senior Vice President, General Counsel and Secretary. He asserted that the Public Staff's recommendation is not based on the premise that the compensation of the identified Aqua America executive officers is excessive or should be reduced. Witness Henry testified that the Public Staff's recommendation is based on the Public Staff's belief that it is reasonable and appropriate for the shareholders of the very large water and wastewater utilities to bear some of the cost of compensating those individuals who are most closely linked to furthering shareholder interests, which are not always the same as those of ratepayers.

Witness Henry further testified that executive officers have fiduciary duties of care and loyalty to shareholders, but not to customers. Consequently, witness Henry maintained, the Company's executive officers are obligated to direct their efforts not only to minimizing the costs and maximizing the reliability of the Company's service to customers, but also to maximizing the Company's earnings and the value of its shares. Witness Henry testified that it is reasonable to expect that management will serve the shareholders as well as the ratepayers; therefore, he argued that a portion of management compensation and pension should be borne by the shareholders.

Public Staff witness Henry testified that in addition to salaries and pensions, these five executive officers receive compensation from incentive plans, including an Annual Cash Incentive Award that for 2016 was based upon Aqua America's budgeted annual net income, and in 2017 the Award was weighted 60% based upon earnings per share. He testified that there are also Long-Term Incentive Awards in the form of Performance Share Awards of Aqua America shares that for 2016 were weighted 60% based on Total Shareholder Return and in 2017 were weighted 45% based upon Total Shareholder Return. He further testified that their Stock Options are based upon achieving at least an adjusted return on equity equal to 150 basis points below the return on equity granted by the Pennsylvania Public Utility Commission during Aqua America's Pennsylvania subsidiary's last rate case proceeding.

Witness Henry testified that the 2017 Proxy Statement on page 46 states:

> The Compensation Committee [of the Board of Directors] believes that by providing the named executive officers with the ability to earn stock options, the named executive officers' interests are aligned with the shareholders' interests as the value of the stock option is a function of the price of the Company's stock.

Public Staff Henry Supplemental Exhibit 1, Schedule 2 Revised, line 7 shows the Public Staff's recommended adjustment to remove 50% of the executive compensation for the top five Aqua America executives totaling $213,756, and Public Staff Henry Supplemental Exhibit 1, Schedule 3 Revised, line 7 shows the Public Staff recommended adjustment to remove 50% of the top five Aqua America executives' pensions and incentive plans totaling $80,845.

Public Staff witness Henry also testified that in each of the respective recent general rate cases, both Duke Energy Progress LLC, (DEP) in Docket No. E-2, Sub 1142, and Duke Energy Carolinas LLC (DEC) in Docket No. E-7, Sub 1146, excluded in their E-1 filings 50% of the compensation of the top four executive officers, as shown on Public Staff Henry Redirect Exhibit 1. He testified that in both cases the Public Staff recommended removing the compensation for a fifth executive, specifically the Chief Legal Officer. He testified that DEP and the Public Staff (in the DEP case) and DEC and the Public Staff (in the DEC case) stipulated to removing 50% of the compensation and benefits of the five top officers. Witness Henry testified that it is the Public Staff's principled position that work and loyalties are divided between shareholders and customers.

Aqua NC witness Kopas, in his rebuttal testimony, contested Public Staff witness Henry's proposed adjustment to remove 50%, including pension and incentives, of Aqua America's top five executives' compensation that is allocated to Aqua NC. Witness Kopas stated that Aqua America sets compensation levels for its executives to attract and retain qualified personnel and to remain competitive in the market. Noting witness Henry's acknowledgement that the Company's executive officers are obligated to direct their efforts to minimizing the costs and maximizing the reliability of the Company's service to customers, witness Kopas framed differently than witness Henry the value to ratepayers of the executives' obligation to support earnings and share value. Witness Kopas focused on the extent to which the efforts of Aqua America's executives benefit ratepayers through controlling costs and managing a strong overall company which allows it to attract capital at lower costs. Witness Kopas asserted that Aqua America officers have a responsibility not only to all investors in the Company, which includes both shareholders and bondholders, but also to employees and "most of all - to customers."

Further, noting the extent of regulation both on the environmental side and the financial side, witness Kopas explained that Aqua America officers are charged with the responsibility of meeting these standards of providing safe and reliable water and wastewater service to customers served by Aqua NC. Witness Kopas asserted that only upon its success in serving ratepayers is Aqua NC afforded an opportunity to earn a return on the dollars invested by shareholders. Witness Kopas offered his opinion that the ability of Aqua NC as a public utility to meet the needs of its customers is the highest priority of all Company employees, and that only then will the financial returns be achieved to attract both debt and equity capital needed in the business. He maintained that executive compensation is a necessary part of the Company's overall cost of service to meet the needs of its customers and that a reduction of 50% to Aqua America executive compensation including pension and incentive plans is not warranted.

Finally, witness Kopas testified that in the 2011 Aqua NC rate case (Docket No. W-218, Sub 319), the Commission rejected the Public Staff's proposed adjustment to remove 50% of the executive compensation for the top four Aqua America executives, however that the Commission did conclude that a 25% adjustment to the executive compensation expense item was reasonable in that case. Witness Kopas stated that if the Commission concludes that an accounting adjustment to executive compensation is justified in this case, then the Company, as an alternative proposal, requests that the percentage disallowance be set at no greater than the 25% adjustment that was found reasonable by the Commission in Docket No. W-218, Sub 319.

On cross-examination by the Public Staff, Aqua NC witness Kopas testified on the executive compensation provisions outlined in the Aqua America, Inc. 2018 Annual Meeting of Shareholders Proxy Statement (Proxy Statement), as filed with the United States Securities and Exchange Commission that was identified during the evidentiary hearing as Public Staff Kopas Rebuttal Cross-Examination Exhibit 2. As requested on cross-examination, witness Kopas read into the record that page 25 of the Proxy Statement states that an objective of the Aqua America executive compensation program was to align the interests of the named executive officers and shareholders.

Witness Kopas also testified that page 27 of the Proxy Statement states that Equity Incentives are:

> Designed to reward named executive officers for (1) enhancing our financial health, which also benefits our customers (2) improving our long-term performance through both revenue increases and cost control, and (3) achieving increases in the Company's equity and in absolute shareholder value and shareholder value relative to peer companies, as well as helping to retain executives due to the long-term nature of these incentives.

Witness Kopas testified that page 28 lists the components of compensation paid to the named executive officers in 2017 and that the Long-Term Equity Incentive Awards provide restricted stock units, performance share units, and options. He testified that page 28 states that the compensation objective for restricted stock units is to: "Align executive interests with shareholder interests; retain key executives."

Witness Kopas stated that the compensation objective for the performance share units as shown on page 28 of the Proxy Statement is to: "Align executive interests with shareholder interests; create a strong financial incentive for achieving or exceeding long-term performance goals."

Witness Kopas further testified that the compensation objective for the options as shown on page 28 of the Proxy Statement states: "Align executive interests with shareholder interests; through performance-based nature, provides strong incentives to achieve core company goals".

Aqua NC witness Kopas further testified that on page 33 it states that for the 2017 annual cash incentive award metrics that 60% of the award is based upon earnings per share. He testified that for the annual cash incentive award, earnings per share metric, the five executives received a 110% payout. Witness Kopas testified that page 36 of the Proxy Statement shows that all five of the executives' actual 2017 cash incentives were substantially greater than the 2017 target cash incentives.

Witness Kopas further stated that the Proxy Statement outlines the performance share awards on page 37 and notes, in part:

> The performance goals to be achieved under the PSU awards have been based on the following performance goals, with the weighting of each goal assessed each year. The Company's total shareholder return (TSR) at the end of the performance period as compared to the TSR of the other large investor-owned water companies (American Water Works Company, American States Water Company, Connecticut Water Service, Inc., California Water Service Group, Middlesex Water Company, and SJW Corporation); the Company's TSR compared to the TSR for the companies in the S&P Midcap Utility Index (Appendix A); the achievement of maintaining Operating and Maintenance expenses within the Company's regulated operations over the performance period; and, the achievement of the three-year cumulative total earnings before taxes in non-Aqua Pennsylvania subsidiaries.

Witness Kopas testified that for the total shareholder return compared to the S&P 400 Utilities Index there was a 127.78% payout to the five executives.

Company witness Kopas further testified that page 41 of the Proxy Statement states:

> Stock Options. In 2017, the Compensation Committee added performance-based stock options to the grants to the named executive officers. The Compensation Committee believes that the award of stock options, when paired with performance and service-based stock awards, completely aligns the interests of the named executive officers with those of the shareholders.

> The Compensation Committee believes that by providing the named executive officers with the ability to earn stock options, the named executive officers' interests are aligned with the shareholders' interests as the value of the stock option is a function of the price of the Company's stock. In addition, stock options provide the use of an additional performance metric for the earning of long-term equity compensation.

Witness Kopas testified that the five executive positions in the Proxy Statement are the same five positions that the Public Staff recommended removal of 50% of their salaries, pensions, and incentive plans.

After considering all of the evidence in the record, the Commission finds the Public Staff's proposed adjustment to allocate 50% of the top five Aqua America executives compensation, including pensions and incentive plans, to shareholders to be unreasonable and not supported by the evidence presented. However, the Commission is persuaded by the record of evidence that an adjustment to remove 25% of the compensation, including pension and incentive plans, of the top five Aqua America executives totaling $106,878 in compensation and $40,423 in pensions and incentive plans is reasonable and appropriate in this proceeding.

In reaching this conclusion, the Commission gives some weight to Aqua NC witness Kopas' rebuttal testimony that adequate compensation plans are necessary to attract and retain qualified executive leadership. The Commission also gives some weight to witness Kopas' testimony that the interests of Aqua NC ratepayers and Aqua America, Inc. shareholders are aligned in terms of the necessity to attract very large amounts of capital at a reasonable cost. The Commission generally agrees that shareholders provide the capital that is essential to the capital-intensive water and wastewater industry, and thus, ratepayers depend on corporate leadership to attract the shareholders whose investment is essential to the ability to serve those ratepayers. This evidence does not support a 50% adjustment as proposed by the Public Staff.

Further, the Commission gives little weight to the Public Staff's observation that the Commission approved 50% adjustments for executive compensation for DEP in its Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase issued on February 23, 2018, in Docket No. E-2, Sub 1142, and for DEC in its Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction issued on June 22, 2018, in Docket No. E-7, Sub 1146. Both DEC and DEP originally filed their rate cases reflecting removal of 50% of the executive compensation of the top four executive officers and later in the proceedings, the Company and the Public Staff reached a stipulation to remove 50% of the executive compensation for the top five executive officers; therefore, the Commission did not resolve the issue through litigation in either case.

The Commission also notes that Aqua NC witness Kopas stated that if the Commission concludes that an accounting adjustment to executive compensation is justified, then Aqua NC recommends as an alternative proposal that the percentage disallowance be set at no greater than 25%, consistent with the Commission's decision in Aqua NC's 2011 rate case proceeding (Docket No. W-218, Sub 319).

Therefore, for the reasons set forth above, the Commission concludes that the Public Staff's proposed adjustment to exclude from the Company's cost of service 50% of the executive compensation for the top five executives named by the Public Staff is inappropriate. However, the Commission is persuaded by the evidence presented including Aqua America, Inc.'s 2018 Proxy Statement that a portion of these expenses should be allocated to the Company's shareholders and that witness Kopas' alternative proposal to remove 25% of such costs is reasonable. The Commission also notes that this decision is consistent with the Commission's decision in Aqua NC's 2011 rate case (Docket No. W-218, Sub 319). The Commission finds it appropriate to allocate 25% of the executive compensation including pensions and incentive plans of the top five Aqua America executives as identified by the Public Staff, to the shareholders, and, therefore, to remove $106,878 in executive compensation salaries and $40,423 in executive pension and incentive plans for a total of $147,301 from Aqua NC's cost of service in this case.

<u>Miscellaneous Expense (Board of Directors Compensation and Expenses)</u>

Public Staff witness Henry testified that the Public Staff has proposed an adjustment to remove 50% of the compensation and expenses associated with the Board of Directors of Aqua America that have been allocated to Aqua NC in this proceeding. Witness Henry specified that the allocations to Aqua NC encompass the Board of Directors' compensation and other miscellaneous expenses. He further testified that the premise of the adjustment is closely linked to the premise of the adjustment made by the Public Staff related to executive compensation. Witness Henry maintained that it is reasonable and appropriate for the shareholders of the very large water and wastewater utilities to bear a reasonable share of the costs of compensating those individuals who have a fiduciary duty to protect the interests of shareholders, which may differ from the interests of ratepayers.

Public Staff witness Henry testified that the Aqua America, Inc. Board of Directors Corporate Governance Guidelines (The Board of Directors Guidelines) state in Section II:

> RESPONSIBILITIES OF THE BOARD
>
> 1. It is the responsibility of the Board to provide guidance and direction on the Corporation's general business goals and strategy, and to provide general oversight of, and direction to, management so that the affairs of the Corporation are conducted in the long-term interests of all its shareholders.

Public Staff witness Henry further testified that Aqua America allocated to Aqua NC $116,838 for Board of Directors compensation and $17,381 for Board of Directors expenses. He testified that the Public Staff recommends that 50% of the Board of Directors' compensation totaling $58,419, and 50% of the Board of Directors' expenses totaling $8,691 be removed as a shareholder expense as shown on Public Staff Henry Supplemental Exhibit 1, Schedule 4 Revised, lines 2 and 3.

Aqua NC witness Kopas stated in his rebuttal testimony that he opposes the Public Staff's proposed adjustment related to Board of Directors compensation and expenses for the same reasons he opposed the Public Staff's proposed adjustment to remove 50% of the compensation paid to the top five executive officers. Aqua NC maintained in its proposed order that the Board of Directors' fiduciary responsibilities inure to the benefit of ratepayers, in terms of assuring the provision of sufficient capital at reasonable costs to support this capital-intensive industry. Witness Kopas stated that, as an alternative to full recovery in cost of service of the Board of Directors' compensation and expenses, he recommended that, at most, the Commission impose a 25% adjustment, consistent with the adjustment made by the Commission regarding executive compensation for the top four executives in 2011, in Docket No. W-218, Sub 319.

On cross-examination by the Public Staff, witness Kopas testified that Public Staff Kopas Rebuttal Cross-Examination Exhibit 1 as admitted into evidence is the Aqua America Board of Directors Guidelines. He testified that on page one it states:

> The following corporate governance guidelines will provide the principles by which the Board of Directors (the "Board") of Aqua America, Inc. (the "Corporation"), will organize and execute its responsibilities along with the requirements of the Corporation's Articles of Incorporation, Bylaws and the laws and regulations governing the Corporation and the Board.

See Public Staff Kopas Rebuttal Cross-Examination Exhibit 1.

Witness Kopas further testified on cross-examination that on page six under Roman Numeral II, Responsibilities of the Board, Number 1, it states:

> It is the responsibility of the Board to provide guidance and direction on the Corporation's general business goals and strategy and to provide general oversight of and direction to management so that the affairs of the Corporation are conducted in the long-term interests of all its shareholders.

See Public Staff Kopas Rebuttal Cross-Examination Exhibit 1.

Witness Kopas also testified that on page eight, paragraph 10, of the Board of Directors Guidelines it states:

> The Executive Compensation Committee will periodically review the compensation package for directors and make recommendations to the Board for any changes. Such reviews shall take place annually. The Board should make changes in its director compensation and only upon recommendation by the Executive Compensation Committee and after discussion and approval by the Board. Both the Executive Compensation Committee and the Board should be guided by the following principles: compensation should fairly pay directors for the work required; compensation should align directors' interests with the long-term interests of shareholders, while not calling into question their objectivity, and the structure of

> the compensation should be simple, transparent, and easy for shareholders to understand.

See Public Staff Kopas Rebuttal Cross-Examination Exhibit 1.

Witness Kopas further testified that he accepted, subject to check, that the word "customer" does not appear even once in the Aqua America Board of Directors Guidelines. Tr. Vol. 12, pp. 202-203.

Based upon consideration of all of the evidence presented in this case, the Commission finds that it is appropriate to remove 25% of the Board of Directors' compensation and expenses from the Company's cost of service in this proceeding. In reaching this conclusion, the Commission has given some weight to the testimony of Aqua NC witness Kopas. The Commission generally agrees with Aqua NC's assertions that adequate compensation is required to attract extremely competent, qualified members of a Board of Directors to lead a company such as Aqua America, Inc. and that North Carolina ratepayers and Aqua America, Inc. shareholders share a mutual interest in a highly skilled and qualified Board. The Commission also generally agrees that ratepayers' best interests depend on a regulated utility's ability to attract capital; in this instance, to support the level of investment required by Aqua NC as a regulated water and wastewater service provider in this state. As stated by Aqua NC, these financial and investment decisions are made at the parent company level and are integrally related to and supportive of the local company's ability to provide safe and reliable service.

However, the Commission is not convinced by Aqua NC's recommendation that no amount of the Board of Directors compensation and expenses should be removed in this proceeding. The Commission agrees with Public Staff witness Henry that a reasonable share of the cost should be removed but does not agree with the Public Staff that a reasonable amount is 50%. Clearly, based on the Board of Directors Guidelines as entered into evidence in this proceeding as Public Staff Kopas Rebuttal Cross-Examination Exhibit 1 one of the responsibilities of the Board of Directors is to provide guidance and direction to the Company so that the affairs of the Corporation are conducted in the long-term interest of all of its shareholders.

The Commission notes that Aqua NC witness Kopas provided the Commission with an alternative proposal to remove 25% of the Board of Directors compensation and expenses from Aqua NC's cost of service in this proceeding, and the Commission finds this alternative proposal to be fair and reasonable.

Accordingly, for the reasons set forth above, the Commission concludes that the Public Staff's proposed adjustment to exclude from cost of service 50% of the expenses associated with Board of Directors' compensation and expenses, in the amounts of $58,419 and $8,691, is inappropriate. However, the Commission is persuaded that a portion of the Board of Directors' compensation and expenses should be allocated to the Company's shareholders, and that Aqua NC witness Kopas' alternative proposal to remove 25% of such costs is reasonable. Therefore, the Commission finds it appropriate to allocate 25% of the Board of Directors' fees to the shareholders and, therefore, to remove $29,210 in Board of Directors' compensation and $4,345 in Board of Directors' expenses from Aqua NC's cost of service in this proceeding.

WATER AND SEWER – RATE INCREASE

Sludge Removal

The Public Staff and the Company disagree as to the appropriate amount of expenses related to sludge hauling. This disagreement centers on the time period that should be used to calculate the expenses.

In its Application, Aqua NC included sludge expense of $536,333 for the test year. On July 20, 2018, the Company provided a post-test year update to sludge expense that included an increase in sludge disposal amounts in the Central/Cary region in 2018. The Company's initial update proposed an increase of $89,875 to the test year sludge expense. On September 4, 2018, Company witness Pearce filed rebuttal testimony proposing a revised increase of $70,424 to the test year sludge expense, which reflects the one-year average of sludge hauling records ending in June 2018.

On August 21, 2018, the Public Staff filed schedules, which included an adjustment to increase sludge expense by $23,049 to incorporate updated sludge hauling expense amounts provided by the Company. With this adjustment, the Public Staff's recommended sludge expense reflects the two-year average of sludge hauling records ending in June 2018 and reflects the projected annual costs for two WWTPs, The Legacy at Jordan Lake and Westfall, which began producing sludge in 2018 after the test year. The projected annual costs for the two WWTPs were based on available historical data for 2018 provided by the Company.

In her prefiled direct testimony, Public Staff witness Darden testified that the Company's sludge hauling data from its Cary/Central region shows an increase in the quantity of sludge hauled in the post-test year period from January 2018 through June 2018 as compared to the test year. Further, witness Darden testified that more significant increases occurred in March, April, and May 2018, and that there was a return to a level closer to the two-year average in June 2018. Tr. Vol. 9, p. 24. On redirect-examination, witness Darden testified that data provided by the Company for July 2018 showed a return to a sludge hauling level below the two-year average. Tr. Vol. 9, p. 47. Witness Darden Redirect Examination Exhibit 1 is a graph showing monthly sludge hauling quantities for the Company's Central/Cary region from July 2016 through July 2018. Ex. Vol. 9, p. 44. The graph shows the two-year average sludge hauling quantity advocated by the Public Staff, which is approximately 300,000 gallons, and the one-year average quantity advocated by the Company, which is approximately 350,000 gallons. The graph shows an increased volume of sludge hauled during the months of March through May 2018 ranging between approximately 425,000 gallons and 600,000 gallons. It also shows a decrease to a level of approximately 325,000 gallons in June 2018, and a further decrease to a level of approximately 290,000 gallons in July 2018.

Witness Darden noted that increased sludge hauling could be a response to sludge storage approaching full capacity and an attempt to prevent associated compliance and operational issues. Witness Darden explained that, if this were the case, sludge hauling could return to regular maintenance levels once sludge levels were reduced. Tr. Vol. 9, p. 24. Witness Darden testified that operational changes could also affect sludge hauling levels. Tr. Vol. 9, p. 36.

Witness Darden opined that, due to the short time frame over which the most significant increases in the Company's sludge hauling occurred, it was unclear whether these increases represented a peak or a trend. Tr. Vol. 9, pp. 24-25. Due to the uncertainty as to whether the comparatively significant increases in sludge hauling that occurred in March through May 2018 would continue going forward, and in order to avoid annualizing what could be an isolated peak in sludge hauling levels, witness Darden advocated the use of a two-year average ending in June 2018 to determine sludge expenses. Tr. Vol. 9, p. 25. Witness Darden noted that the two-year average takes into account The Legacy at Jordan Lake and Westfall WWTPs, which both began producing sludge in 2018. Id. Witness Darden further noted that the two-year average accounts for the operational changes the Company indicated it made at the WWTPs by incorporating sludge hauling data provided by the Company through June 2018. Tr. Vol. 9, pp. 32-33.

Aqua NC witness Pearce testified in prefiled rebuttal testimony that the Company had made changes to its WWTP operations to reduce mixed liquor suspended solids concentrations that would, in turn, increase sludge production. Tr. Vol. 13, p. 122. Witness Pearce provided an example calculation to demonstrate how decreasing mixed liquor suspended solids results in an increased sludge production rate. Tr. Vol. 13, p. 123. The calculation assumes a number of values including values for WWTP operating capacity, hydraulic retention time, and mixed liquor suspended solids concentration. Witness Pearce did not indicate the source of the values used in his example calculation. Witness Pearce also included in his rebuttal testimony a graph from the 1992 edition of the Water Environment Federation Manuals of Practice showing net sludge production as compared to solids retention time. Tr. Vol. 13, pp. 123-124. Witness Pearce extrapolated from the graph that a greater than 10% increase in sludge production would result from improving the pollutant removal efficiency of WWTPs. Like the example calculation provided by witness Pearce, the graph and extrapolation assumed values the source of which witness Pearce did not disclose. Witness Pearce gave no indication in his prefiled rebuttal testimony whether the values upon which his example calculation and extrapolation were based represent actual operational data from one or more of the Company's WWTPs. It was not until he was questioned about the source of the assumptions on cross-examination that witness Pearce asserted that his example calculation and extrapolation were based on actual data from an Aqua NC WWTP. Tr. Vol. 13, p. 134. Witness Pearce recommended sludge expense, totaling \$606,756.78 (\$507,699.28 for Aqua NC Sewer and \$99,057.50 for Fairways Sewer) based on data from July 2017 through June 2018. Tr. Vol. 13, p. 125. This amount represents an increase of \$70,424 over the amount of sludge expenses stated in the Company's Application.

On cross-examination, witness Pearce verified that, based on the extrapolation from the graph included in his rebuttal testimony, operational changes made the second week of April 2018 would result in an approximately 10% increase in sludge production. When confronted with the fact that the Company's actual sludge hauling data shows an increase in sludge hauling far in excess of 10%, witness Pearce testified that the 10% increase he estimated would be accurate "over the 12-month period." Tr. Vol. 13, pp. 135-136. Witness Pearce acknowledged that the actual sludge hauling levels for eight of the 12 months that make up the test period advocated by the Company were lower than the Company's one-year average level. Tr. Vol. 13, p. 131.

On redirect-examination of witness Pearce, the Company introduced Aqua Pearce Redirect Exhibit 1. That exhibit is a graph showing monthly sludge hauling quantities for the Company's

Central/Cary region from July 2016 through August 2018. Ex. Vol. 9, p 65. Witness Pearce testified that he had received the Company's sludge hauling logs for the month of August 2018, and that the level of sludge hauled during the month of August 2018 was higher than the two-year average advocated by the Public Staff. Tr. Vol. 13, p. 145.

The Commission has carefully reviewed the evidence in this docket and concludes that it is appropriate to adjust sludge hauling expense by $23,049 based on the two-year average advocated by the Public Staff. By basing sludge hauling expenses on an average of the two-year period ending June 2018, this will take into account the addition of two WWTPs that started producing sludge in 2018 and it will reflect other operational changes made at some of the Company's WWTPs. The use of the two-year period average also ensures that the uncharacteristically high levels of sludge hauling that occurred during the months of March, April, and May 2018 are given appropriate emphasis in determining expenses. Although the Commission acknowledges that the operational changes made to the Company's WWTPs in April 2018 have increased the quantity of sludge hauled by Aqua NC for several months in 2018, the Commission is not persuaded by the testimony of witness Pearce that such operational changes would result in the approximately 10% increase in sludge production rate indicated by his example calculation. Witness Pearce did not clearly set forth the source of the values used in his example calculation for which he bases his estimated 10% increase in the sludge production rate. Consequently, the Commission gives minimal weight to the testimony of witness Pearce in that regard.

For the foregoing reasons, the Commission determines that using the two-year average advocated by the Public Staff rather than the one-year average advocated by the Company will produce a level of sludge hauling expense that is more representative of the Company's actual ongoing sludge hauling expense.

__Testing Expense__

In its Application, the Company included testing expenses of $971,149 for the test year. On July 20, 2018, the Company provided a post-test year update to testing expense that included an increase in NOD site testing. The Company's update increased test year testing expense by $111,538. In her direct testimony, Public Staff witness Darden recommended that testing expenses in the amount of $882,746 should be approved, with an increase of $19,426 for NOD site testing. Witness Darden's pro forma adjustments resulted in a decrease of $88,402 to the level of test year compliance and operational testing expense as proposed by the Company in its Application and a decrease of $92,112 to Aqua NC's proposed post-test year update of $111,538 to NOD testing expense.

__Annual Compliance and Operational Testing Expenses__

Witness Darden testified that she did not agree with Aqua NC's use of its per book amounts or the manner in which the Company calculated pro forma adjustments. Witness Darden further stated that the Company's calculations did not account for the variation in the frequency with which specific water quality tests must be performed, as some tests are conducted with different frequencies of every three, six, or nine years, and therefore should be amortized by the number of years. The Company filed a testing expense with pro forma adjustments based on comparisons of the test year to the past three years individually and as an average. Witness Darden testified that she disagreed with the Company's amortization, noting that it does not capture the amortization of tests with frequencies that exceed one year. Tr. Vol. 9, p. 39.

Public Staff witness Darden calculated testing expenses in the present case in the same manner that the Public Staff has traditionally calculated the testing expense – using current testing schedules going forward, amortizing the expense over the number of years corresponding to the testing frequencies for the various tests, and using the current unit costs of the tests. Tr. Vol. 9, p. 18. Witness Darden noted that the Company provided the Public Staff with the schedules establishing the current required compliance testing frequency for each of its water and wastewater systems.

On cross-examination, witness Darden acknowledged that her calculations did not include operational testing and were based on EDR 3. Witness Darden noted that Aqua NC has not tracked operational testing historically, and that the appropriate amount of operational testing expense has been agreed upon by the Company and the Public Staff in the past. Further, witness Darden testified that, in this case, the Company and the Public Staff did not agree. Witness Darden recommended that the testing expense should include the required compliance testing and the NOD testing update provided by Aqua NC. Witness Darden testified on cross-examination that the Public Staff recognizes that operational testing should be recovered as long as it is reasonable and cost-effective. Tr. Vol. 9, pp. 41-42.

Company witness Berger testified on rebuttal that she disagreed with the adjustments made by Public Staff witness Darden and noted that witness Darden began her inquiries by requesting, in EDR 3, "the minimum water system testing test type and frequency as determined by DEQ". Witness Berger testified that the information requested did not provide a full picture and did not contain sufficient information to warrant the adjustments made by witness Darden.

Witness Berger asserted that the information requested by the Public Staff in EDR 3 and the follow-up request on August 3, 2018, only accounted for minimum testing compliance required by DEQ. Witness Berger further stated that compliance testing is designed to determine compliance with the rules and regulations at a moment in time, not just the time in which the compliance testing occurred. Witness Berger then explained the difference between compliance testing and operational testing, noting that operational testing is utilized by the operator to determine the effectiveness of treatment and for proactive identification of issues. Tr. Vol. 16, p. 136.

Witness Berger testified that operational testing is performed continuously based on need and judgment of the operator. She observed that regulatory agencies do not establish operational testing requirements but they do expect the utility to understand the treatment methods used to ensure the delivery of drinking water that meets regulatory requirements.

Further, witness Berger acknowledged under cross-examination on September 25, 2018, that the Company was unable to provide the Public Staff with operational testing expenses when the Public Staff requested them on September 5, 2018. In particular, she testified, "if we could have been asked to provide the operational . . . versus the compliance we could have done so, just not on such a short timeline." Tr. Vol. 16, p. 166. However, when asked if Aqua NC currently is tracking compliance and operational testing separately, witness Berger responded that some of the Company's operational testing expenses were still not being tracked. Id.

On cross-examination, witness Berger also stated that the Public Staff's request for information concerning the test year level of operational testing would have required her to go line-by-line through each monthly invoice–typically 150-250 pages each. To comply with the Public Staff's request, in this regard, as best as possible within the short time frame, witness Berger testified that a software package was utilized to provide approximately 85-90% of the data requested from 2016 up to August 31, 2018. She commented "[a]nd I think it had over 20,000 entries in it so it provided at least some known documentation to support". Tr. Vol. 16, pp. 164-165.

The Commission recognizes that both the Public Staff and the Company are in agreement that operational testing is a reasonable operating expense; it is a testing expense incurred by Aqua NC separate and apart from the compliance testing required by DEQ, and a reasonable level of this type of testing expense should be included in test year operating expenses. However, in the present proceeding neither the Public Staff nor Aqua NC has submitted to the Commission evidence which clearly supports the dollar amount of a reasonable level of operational testing expense. Aqua NC contends that the Public Staff did not ask for this specific information early-on in the audit process in EDR 3, and therefore the Company had insufficient time to accumulate this information and provide it to the Public Staff for review. The Public Staff asserts that Aqua NC does not track its per book operational testing expense separately from its per book compliance testing expense such that the information can be readily identified and provided to the Public Staff for review.

Historically, the Public Staff has restated the amount of compliance testing for all regulated water utilities because per book amounts, typically, do not reflect: (1) current testing schedules going forward; (2) the amortization of the expense over the number of years corresponding to the testing frequencies for the various tests; and (3) the current unit costs of the tests. Aqua NC's per book accounting for testing expense provides no reason for exception to this practice by the Public Staff. The Commission acknowledges that in Aqua NC's last rate case proceeding (Sub 363), Public Staff witness David Furr filed similar testimony regarding the problems that arise when per book amounts are used to calculate pro forma testing expense. As a result of prior rate case audits by the Public Staff and Commission decisions, the Company should be well aware of the Public Staff's method for calculating its recommended pro forma level of testing expense.

Based upon the testimony received in this proceeding, the Commission recognizes the distinction between compliance testing and operational testing and finds that operational testing is essential to the proper operation of a water utility. Further, during the course of the hearing in this matter, there was much discussion about the need to maintain and improve water quality for customers. The Commission understands that operational testing is an essential part of that effort. However, in this proceeding, the Commission is not persuaded that the level of operational testing expense the Company seeks to recover is reasonable. The Company did not maintain adequate records of its operational testing expenses separate from its compliance testing such that the Company could provide the Public Staff with an appropriate analysis of the cost data for its test year operational testing expense in its Application. A review of such expenses for reasonableness is necessary in order for the Public Staff to make a recommendation to the Commission for inclusion in test year operating expenses in this proceeding.

The Commission understands from the testimony of witness Darden that historically, Aqua NC and the Public Staff were, through discussions, were able to agree upon a testing expense amount which included both compliance and operational testing expense; however, in the present proceeding the parties have not been able to agree on testing expense. In her rebuttal testimony, witness Berger referenced Aqua NC's response to NCUC Form W-1, Item 12(b), which presented comparisons between Aqua NC's test year operating expenses and its prior three years' per books operating expenses, in support of the Company's position that the Public Staff's recommended level of testing expense is incomplete. Nonetheless, witness Berger did not specify what portion of the testing expense included on Aqua NC's NCUC Form W-1, Item 12(b) related to the level of operational testing incurred in the test year and prior years; nor did she provide the amount of operational testing agreed upon by the Company and the Public Staff and approved in prior rate case proceedings.

The Commission is of the opinion that, as discussed previously in this Order, due to the need for Aqua NC to maintain and improve water quality for customers in the future, some level of operational testing fees will be required to accomplish that objective. In this proceeding, the Public Staff did not present a level of operational testing fees expense for the Commission's consideration. The Commission agrees with the testimony of witness Darden that Aqua NC's use of per book numbers to calculate its proposed level of operational testing fees expense is flawed as it does not generally reflect current testing schedules going forward, the appropriate amortization periods, and the current unit costs of the tests. Further, Aqua NC's per book amounts do not track operational testing expense such that those expenses can be readily quantified. The Commission is of the opinion that Aqua NC's utilization of a software package to provide approximately 80-90% of the data requested by the Public Staff for the period 2016 through August 31, 2018 and providing that information to the Public Staff to sort out does not equate to sufficient evidence. Further, Aqua NC's contention that since such report contained approximately 20,000 entries, it provided at least some known documentation to support actual operational testing expense does not satisfy the Company's responsibility in documenting this expense. The Commission does not dispute that Aqua NC has incurred operational testing expense during the test year and such expense will continue. However, it is the responsibility of the utility to provide justification for the costs it seeks to recover from customers in a manner that can be audited and evaluated by the Public Staff within a reasonable timeframe. In all fairness, the Commission does acknowledge that the Public Staff could have sought this information sooner in its discovery process; nonetheless, that does not alter the requirement that Aqua NC should provide this information in a manner that can be effectively reviewed and evaluated by the Public Staff.

Although the Commission finds that Aqua NC failed to provide sufficient and specific evidence concerning its test year level of operational testing in the present proceeding, the Commission determines that some level of operational testing expense is important. Thus, due to the lack of specific evidence in the record on this issue, in order to determine an appropriate level of operational testing fees to include in this proceeding, the Commission has examined its prior Aqua NC rate case final orders with respect to total testing fees approved for Aqua NC Water Operations. Based upon a review of the level of total testing fees approved by the Commission in the Sub 363 Order and Sub 319 rate case proceedings for Aqua NC Water Operations, and considering that there are many factors involved when calculating the total ongoing level of testing expense, the Commission, in its discretion, finds and concludes that 50% of the amount in dispute or $44,201, should be included for operational testing expense in this proceeding.

Furthermore, the Commission strongly encourages Aqua NC to maintain its books and records on a going-forward basis in a manner that will allow the Company to track its operational testing expense separately from its compliance testing expense such that those expenses can be readily quantified by Aqua NC, presented to the Public Staff for review of reasonableness, and proffered to the Commission for inclusion in test year operating expenses in the Company's next rate case. If Aqua NC should determine that such separate accounting would be cost-prohibitive to implement, the Commission recommends that the Company work with the Public Staff to formulate a mutually-acceptable method to determine and present operational testing costs in future rate case proceedings.

Based upon the foregoing, the Commission finds and concludes that the appropriate level of testing expense is $926,947, consisting of $882,746 for compliance testing and $44,201 for operational testing, prior to considering the update for the NOD site testing expense.

<u>NOD Testing Expense</u>

Witness Darden testified that the Company filed updated testing expenses for a post-test year sampling program in Aqua NC's Central Cary area as a result of NODs for approximately 50 systems. DEQ and Aqua NC set up short-term sampling for the sites that were issued NODs. In calculating testing expenses associated with NOD sites, the Company annualized the amount spent between January and June 2018 and arrived at a total of $111,538. Whereas, Public Staff witness Darden recommended the addition of $58,278 as a sub-category to testing expense to account for NOD site testing. Tr. Vol. 9, p. 21. In calculating this amount, witness Darden applied a price decrease which took effect in April 2018 to the period April through June 2018. For ratemaking purposes, witness Darden testified that the total NOD site testing expense would be averaged over three years. Witness Darden disagreed with annualizing these costs, as the Company proposed, on the basis that DEQ Public Water Supply Section (PWSS) could reduce the sampling frequencies for NOD sites after the third testing quarter, which ended September 30, 2018. Under cross-examination, witness Darden noted that the testing that occurred during the one-year period ending September 2018 would provide a historical benchmark, and, therefore, it was likely that reductions in sampling frequencies would occur after that point. She stated that additional sampling data may not be necessary at the same sampling frequency for every site. Tr. Vol. 9, pp. 43-44. For example, if all the samples at a particular site are consistent, the sampling frequency could be reduced due to the consistency and the fact that the samples provide a benchmark of historical testing data. Tr. Vol. 9, p. 45. Witness Darden testified on redirect that if certain sites are consistently producing the same results on a monthly basis, the testing frequency could be changed to quarterly, then to semiannually, and then to annually if the historical data supported it. Also, she pointed out that when treatment is installed, a different sampling schedule would be utilized from the sampling schedule that had been required for the initial monitoring. Tr. Vol. 9, p. 50.

Due to the likelihood that sampling frequencies will be reduced after September 2018, the Public Staff recommended that the actual expenses of $58,278 spent on the NOD site testing be recovered over three years and that testing expenses continue to be tracked and then recovered in future rate cases. Therefore, the Public Staff recommended an increase to test year operating expenses for NOD site testing of $19,426 which results from the amortization of such total testing expenses of $58,278 over three years.

Company witness Berger testified in her prefiled rebuttal testimony that witness Darden was incorrect when she testified that sampling frequencies for NOD sites could be reduced after the third quarter of 2018. She further testified that, pursuant to the State's rules regarding the concentration of iron and manganese, DEQ determines the sampling frequencies required for these constituents, and that the requirement to sample for these constituents is ongoing. Tr. Vol. 16, p. 140. However, on cross-examination, witness Berger acknowledged that, in practice, the utility submits a recommendation regarding the appropriate testing frequency to DEQ for its approval. She further acknowledged that DEQ has the authority to amend testing schedules for NOD sites. Tr. Vol. 16, p. 169. In an excerpt from an audio recording made by witness Berger of an August 29, 2018, meeting between Aqua NC, DEQ PWSS, and the Public Staff, Bob Midgette, the head of the operational branch of DEQ PWSS, stated that he anticipates Aqua NC could reduce NOD site testing frequency from monthly to quarterly in 2019, and possibly to annually thereafter if the data support such a reduction.[1] When asked about Mr. Midgette's statement under cross-examination, witness Berger acknowledged, "[Mr. Midgette] does make that recommendation on a specific case-by-case basis where we have the data that demonstrates that we have a resolution in place that, yes, we can propose [a reduction in testing frequencies]." Witness Berger went on to testify that the Company intended to use surplus NOD testing expenses resulting from any reductions in NOD testing frequencies to perform sampling on non-NOD sites to proactively address secondary water quality issues. Tr. Vol. 16, p. 176.

The Commission finds and concludes that the evidence of record demonstrates that NOD site-testing frequencies will be reduced after September 2018 and it is, therefore, appropriate that actual costs should be recovered and amortized over three years as recommended by the Public Staff. The future costs associated with the NOD site testing are not currently known and measurable and, therefore, it is appropriate that they be recovered in future rate cases. Based upon the foregoing, the Commission concludes that the total annual testing expense for use in this proceeding, including the increase of $19,426 for NOD site testing recommended by the Public Staff is $946,373 ($926,947 + $19,426).

Purchased Water

In its Application, Aqua NC included purchased water expense of $1,947,892 for the test year ending September 30, 2017. Public Staff witness Junis proposed an adjustment to decrease the Company's filed purchased water expense of $1,947,892 by $73,670. The Company and the Public Staff disagree on the appropriate amount of allowable, recoverable water loss.

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[1] A transcription of two excerpts from the audio recording was entered into the record as Public Staff Berger Cross-Examination Exhibit 5. A CD containing the excerpts from the audio recording transcribed in Exhibit 5 was entered into the record as Public Staff Berger Cross-Examination Exhibit 6.

WATER AND SEWER – RATE INCREASE

Company witness Gearhart stated in his direct testimony that for all purchased water systems, the test year actual volumes of water purchased were used with the most recent/known vendor pricing applied to that volume. He explained that a pro forma adjustment was made to include purchased water expense from the City of Belmont, because in June 2018 the City of Belmont began to supply water to three of Aqua NC's subdivisions which had previously been supplied from Aqua NC's wells.[1] Witness Gearhart testified that during discovery, the Company found that there were purchased water systems with abnormal volume activity during the test year. He stated that these systems merited adjustments and in response to a Public Staff engineering data request, resulted in a reduction in the Company's annual purchased water expense. The Company adjusted the purchased water expense to $1,941,621, a decrease of $6,271 from the originally filed amount. He stated that the response also included an adjustment for the vendor's price increase that went into effect in July 2018. Tr. Vol. 5, pp. 217-218.

Public Staff witness Junis testified that Aqua NC's operations resulted in test year water losses exceeding 15% for nine of its third-party water provider accounts. The highest two being the City of Asheville and the City of Concord that resulted in 74% and 64% unaccounted for purchased water, respectively. Tr. Vol. 12, p.155.

In response to Public Staff EDR 13,[2] the Company provided explanations for unaccounted for purchased water supplied by the City of Asheville, City of Concord, City of Mount Airy, Davidson Water, Harnett County, Iredell Water, Town of Pittsboro, and Town of Spruce Pines. The response stated in part that "Aqua NC has a purchased water loss percentage of 13%." Witness Junis testified that the overall 13% included a surplus (Aqua NC sells more gallons than it buys) from the City of Lincolnton and Aqua NC buys approximately half of the overall purchased water for its Aqua NC Water rate division from Johnston County and sells that purchased water to customers in the Flowers Plantation development. Tr. Vol. 12, pp. 155-156.

In response to Public Staff EDR 53,[3] the Company provided an update to its purchased water workpapers, which witness Junis testified that the update included the quantity of gallons purchased from the City of Lincolnton and an increase in the cost of purchasing water utility service from Johnston County. Witness Junis provided Table 12 in his direct testimony that details the Company's purchased water quantities, water losses, and the Public Staff's recommended adjustment based on an acceptable level of water loss of 15%. Tr. Vol. 12, p. 156.

Based on the most recent, available information, Public Staff witness Junis concluded that the customers should not pay for excessive water loss due to lack of oversight, maintenance, and repair. Witness Junis recommended a decrease of $73,670[4] to the purchased water expense filed by the Company.

[1] These affected subdivisions include Heather Glen, Highland on the Point, and Southpoint Landing Subdivisions located in Gaston County, North Carolina. See Docket No. W-218, Sub 491 for additional information.

[2] The Company's response to Public Staff EDR 13 Q1 was entered into the record as Junis Exhibit 23.

[3] The Company's response to Public Staff EDR 53 Q3 with witness Junis' adjustments was entered into the record as Junis Exhibit 24.

[4] Exhibit B3-b-a to the Application listed a variance of $49.64 between columns (i) and (j) that was excluded from the Application, however, it was included in the Company's and witness Junis' workpapers. Whether the variance

WATER AND SEWER – RATE INCREASE

In reference to the non-revenue water analysis that Company witness Berger included in her rebuttal testimony, under cross-examination Public Staff witness Junis stated that the difficulty with utilizing that method is there is not the level of detail, in terms of information available to do a water balance analysis as described by the American Water Works Association (AWWA). Tr. Vol. 10, p. 123. On cross-examination, witness Junis agreed that Aqua NC does not meter hydrant flow when flushing, and stated that doing so would provide the level of detailed information necessary for an accurate non-revenue water or water balance analysis. Tr. Vol. 10, p. 126.

Concerning the issue of water loss that was captured prior to water main replacements to address leaks, Public Staff witness Junis testified that he considered whether it is appropriate for the Company to recover both the extremely high water loss amount that the Aqua NC system is not now experiencing due to leak repairs and the capital costs associated with the repairs. Tr. Vol. 10, p. 128.

Public Staff witness Junis clarified that allowing for a reasonable amount of water losses is not the same as discouraging the Company from doing flushing. The reasonable amount of water losses may include flushing amounts. The Public Staff requested records of the Company's flushing and the Company could not quantify their flushing. Tr. Vol. 10, p. 129.

On cross-examination, Public Staff witness Junis stated that the 15% of allowable water loss is reasonable due to AWWA information. AWWA recommends that action needs to be taken to address water loss at 15%. Witness Junis further clarified that, after the Company addressed water loss issues for systems exceeding 15%, those systems were under the 15% water loss threshold. Tr. Vol. 10, p. 130.

In her rebuttal testimony, Company witness Berger contended that the Public Staff's use of the concept for Unaccounted for Water is an outdated measure of water loss and that a certain amount of water is necessary for system processes to maintain compliance with DEQ regulations. Tr. Vol. 16, pp. 123-124.

On cross-examination, Company witness Berger stated that water loss calculations should consider other factors that contribute to water loss including environmental factors and construction factors. Tr. Vol. 16, p. 146. Company witness Berger pointed out that her rebuttal testimony included background information indicating that, for a number of systems, water loss was due at least in part to operational flushing to address Disinfection-By-Product (DBP) issues. Tr. Vol. 16, p. 148. On further cross-examination, witness Berger confirmed that, with the exception of the Town of Pittsboro, her rebuttal testimony, filed on September 4, 2018, was the first time Aqua NC indicated that DBP flushing contributed to its water loss, even though Aqua NC had previously provided two responses to data requests on that very issue. Tr. Vol. 16, pp. 154-155.

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is included or not would impact the filed amount and the recommended adjustment but not the recommended level of expense. For the purposes of discussion, the variance has been reduced ($73,719.33 - $49.64 = $73,669.69) from witness Junis' adjustment.

In her rebuttal testimony, Company witness Berger testified that witness Junis failed to investigate root causes and did not consider the Company's proactive measures to address customer concerns and regulatory requirements. Tr. Vol. 16, p. 134. However, on cross-examination, witness Berger agreed that witness Junis' request for a detailed explanation for water losses in EDR 13, Q 1 was an investigation of the root causes of those losses. Tr. Vol. 16, p. 151. The Public Staff contended that witness Berger's testimony on cross-examination contradicted her prefiled rebuttal testimony on this issue.

In reference to a Public Staff engineering data request[1] in the rebuttal testimony of Company witness Berger, she stated that the Company was unable to provide historical data for flushing records at this time, due to the short timeline to satisfy this request. She also stated that the Company cannot provide an accurate estimate of the amount of flushing required in the future. Tr. Vol. 16, p. 156.

Under cross-examination, Company witness Berger confirmed that Aqua NC had 74% water losses in the Asheville system for the test year. Company witness Berger stated that she does not think it is reasonable for customers to pay for 74% water loss. She stated that she does agree it is high, but that it was a case where the circumstances behind the specific leak and attempts by the Company to repair the leak should be considered. Tr. Vol. 16, pp. 158-159.

In her rebuttal, Company witness Berger stated that witness Junis failed to factor the costs involved in any potential infrastructure improvements that may be associated with further addressing the water loss issues. Tr. Vol. 16, p. 134. Under cross-examination, witness Berger agreed that water main replacements, main extensions to eliminate dead ends to help address DBP issues, and treatment systems and filters to comply with water standards are all eligible for recovery between rate cases through the WSIC mechanism. She added that she did not see where witness Junis had applied that reasoning in his calculation. Tr. Vol. 16, pp. 159-160.

While the Commission acknowledges that the testimony presented by Aqua NC in this proceeding explains several operational reasons why some level of water loss in Aqua NC's systems will exist, the Commission finds that it is in the best interest of both Aqua NC and its customers for the Company to be mindful of an acceptable standard of water loss as it monitors its water losses from period to period. The Commission is of the opinion that with an established water loss standard in place, Aqua NC will more aggressively seek to investigate water losses and will strive to identify the cause(s), and make the necessary corrections, if applicable, more expeditiously. Public Staff witness Junis recommended that an acceptable standard for water loss should be 15% based on an AWWA recommendation that action needs to be taken to address water loss occurring at that level. Although Aqua NC witness Berger disagreed with witness Junis' utilization of a maximum system-specific acceptable overall water loss of 15%, in part, because it fails to consider the size, age, or operating characteristics of individual systems, she did not offer any other acceptable standard or detailed criteria to hold Aqua NC accountable to an acceptable level of water loss. Rather, witness Berger testified that the Company performs water audits in accordance with the AWWA Manual 36, Water Audits and Loss Control Programs. In particular,

[1] Public Staff Engineering Data Request #58, Questions 3-5 and 7 with the Company's responses were entered into the record as Public Staff Berger Rebuttal Cross-Examination Exhibit 3.

witness Berger stated that Aqua NC reviews water purchased versus water billed and then requires its operations group to investigate and provide explanations.

Based upon the evidence received in this proceeding, the Commission agrees with the Public Staff that an acceptable water loss percentage should be applied to Aqua NC's purchased water expense. The Commission finds and concludes that 15% is a reasonable and appropriate amount of recoverable water loss for use in this proceeding. The Commission accepts for purposes of this proceeding that the 15% of recoverable water loss encompasses reasonable levels of necessary operational flushing, flushing due to compliance issues, and leaks; and also encourages the Company to monitor and address water losses. Accordingly, as recommended by the Public Staff, the Commission finds that the appropriate level of annual purchased water expense in this proceeding is $1,874,173.

Regulatory Commission Expense

In regard to regulatory commission expense, which is also known as rate case expense, the Public Staff and the Company disagree on the amortization period for the applicable expenses. In its Application, Aqua NC included a three-year amortization period for rate case expense. In her direct testimony filed on August 21, 2018, Public Staff witness Cooper recommended a three-year amortization period for rate case expense, except for the depreciation study, which she recommended a five-year amortization period.[1]

As part of her supplemental testimony, Public Staff witness Cooper recommended an amortization period of five years for rate case expense instead of the three years she initially recommended in her prefiled direct testimony. Her supplemental testimony did not explicitly explain the Public Staff's reasoning for the adjustment to the recommended amortization period. On cross-examination, Public Staff witness Cooper testified that five years was more favorable to customers because of the extraordinary number of attorneys that were representing the Company.[2] This would in turn result in a substantial increase in attorney fees for this proceeding. The Public Staff contended that another reason for its recommendation of a five-year amortization is the fact that the Company utilizes the WSIC and SSIC mechanism for upgrades and improvements between rate cases. Because the Company has the ability to recover some of those costs before a rate case is filed, it seems reasonable to the Public Staff that there would be a greater time span between rate case filings. As noted by the Public Staff, the time span between this rate case and the previous rate case was approximately four and a half years. Tr. Vol. 8, p. 114.

On cross-examination, witnesses Cooper and Henry agreed that it is possible that Aqua NC would hit the 5% cap on WSIC before the next five years lapse, in light of the emphasis on capital investments in the conversations about solutions to the secondary water quality concerns expressed by customers. Witness Cooper acknowledged on cross-examination her understanding that it has been usual and customary for the Public Staff to recommend utilization of a three-year amortization period for regulatory commission expense in water and wastewater cases. Witness

[1] See Cooper Exhibit 1, Schedule 3-5, Column B filed on August 21, 2018.

[2] On August 23, 2018, a Notice to Appear was filed on behalf of the Company adding three additional attorneys for this proceeding. This brought the total number of attorneys representing the Company to six, including Aqua America attorney Kim Joyce.

Henry testified that this case has imposed a major workload on both the Public Staff and the Company, acknowledged (implicitly) by the participation of multiple Public Staff attorneys, and he agreed that a largely unsettled case of this sort would be expected to result in increased legal fees. He noted that the Public Staff is interested in smoothing out that financial impact to customers by amortizing those fees over a longer period, and he also acknowledged the potential of a cash flow impact for the Company if a longer amortization period is used.

As stated earlier, the recommendation for the five-year amortization was filed in the supplemental testimony of Public Staff witness Cooper, but there was no rebuttal filed by the Company related to this issue. On cross-examination, Company witness Gearhart stated that this issue was not included in his rebuttal testimony because he had not been made aware that witness Cooper's proposed amortization period had changed. Tr. Vol. 13, p. 104.

Witness Gearhart testified on cross-examination by the Public Staff that in the Company's initial schedules, the amortization period was listed as three years, except for the depreciation study, which was five years. Referring to the relevant pages from the rate case Orders of 2009, 2010, 2011, 2012, and 2014, he noted that the amortization period for these kinds of expenses was three years in all instances, except for expenses associated with depreciation studies. Witness Gearhart disagreed with the Public Staff's change in methodology, stating that it does not reflect the amount of time that historically existed between rate cases. He stated that this is the first time during his tenure where Aqua NC's rate case interval has exceeded three years, and argued that this interval was an outlier, noting that the Company was "...spending a lot of money." He testified that the Company's Three Year WSIC plan has a $27,000,000 cap, and that the cap is anticipated to be met in the next three years.

Witness Becker agreed on cross-examination that Aqua NC continued to collect in its revenue requirement for rate case expenses that were amortized for three years in the last rate case, pursuant to the Sub 363 Order. However, he noted that this is the first time the Company has been able to stay out that long, that the continuation of revenues based on the prior amortization has helped the Company hold off on a rate case filing, and that it has offset increases in other expenses that have not been updated since the last rate case. He agreed on cross-examination that with respect to that single item, one could say the Company had "over-recovered."

Witness Becker, on redirect-examination, discussed the efforts, commitment of resources, and difficulty associated with attempting to respond to discovery requests that delved into events that occurred as far back as 2005, for purposes of meeting challenges posed in this rate case. He contended that the Company's effort to reconstruct the history and the inputs into Aqua NC's decisions over the period of time from 2005 until now was comprehensively undertaken and was very difficult. He also discussed, on redirect-examination of his rebuttal testimony, a series of examples of the magnitude and pace of the discovery process, which started late and continued through the Friday before the commencement of the evidentiary hearing on the following Tuesday.

Witness Becker discussed the Company's need for a heightened level of legal counsel for this rate case as a result of the certainty or the likelihood that: (a) there would be no global settlement discussions of any kind prior to the Public Staff filing its testimony; (b) certain significant issues were not going to settle, under any foreseeable circumstances; (c) the Company would have 10 days from receipt of the Public Staff's testimony to respond, attempt to negotiate, and develop extensive rebuttal testimony; (d) significant impacts on company rate base were at stake; (e) little time would remain after the filing of rebuttal to prepare for a fully-litigated case; and (f) the Company was accused by the Public Staff of mismanagement. Additionally, witness Gearhart spoke to the volume of discovery in this case, which required internal response and legal support. Witness Becker testified that Aqua NC had conducted the case up to that point with the assistance of two consulting attorneys and had no internal staff – legal or otherwise – dedicated entirely to regulatory support.

In its proposed order, Aqua NC requested that it be allowed to recover its total rate case expenses related to the current proceeding over a four-year period, except for the 2017 depreciation study for which a five-year amortization period was requested.

On November 19, 2018, as required by the September 17, 2018 Stipulation, Aqua NC filed the affidavit of Dean R. Gearhart which provided the rate case expense incurred to date in conjunction with the present proceeding. Affiant Gearhart requested that the Commission approve and include total rate case costs in this proceeding in the amount of $818,397. Affiant Gearhart explained that he provided the Public Staff all required documentation related to such update and that all cost amounts provided were for actual costs incurred to date except for one estimate related to the costs of preparing and mailing notices to customers once the Commission issues its final order in this proceeding.

As detailed in the affidavit of Gearhart, the total rate case costs consists of the following:

Description	Amount
Aqua Service Company Capitalized Time	$5,699
Billing Analysis/Rate Design	52,416
Consultants	38,536
Depreciation Study	58,664
External Audit Fee	2,000
Legal Fees – Current Proceeding	417,876
Legal Fees – Defending WSIC/SSIC[1]	55,560
Mailing/Printing Customer Notices	99,737
NCUC Hearing Costs[2]	11,057
NCUC Rate Case Filing Fee	500
ROE/Capital Structure Witness	48,537
Travel Expenses	1,815
Environmental Finance Center Studies[3]	26,000
Total Rate Case Expense	$818,397

[1] This expense is for the costs associated with defending the Commission's final Order in the Sub 363 rate case before the North Carolina Supreme Court in response to the appeal taken by the North Carolina Department of Justice.

[2] This expense item is for the costs associated with outside court reporting services.

[3] The Environmental Finance Center "Studies of Volumetric Wastewater Rate Structures and a Consumption Adjustment Mechanism for Water Rates of Aqua North Carolina, Inc." were filed jointly by Aqua NC and the Public Staff in Docket No. W-218, Sub 363A on March 31, 2016. These studies were prepared for use in this proceeding and were in fact used and cited by both Aqua NC and the Public Staff in this case.

Consequently, as a result of these final updated rate case costs, Aqua NC requested that the Commission include in rates in this proceeding annual rate case expense of $201,666.

On November 26, 2018, the Public Staff filed its response to Gearhart's affidavit. The Public Staff stated that it has reviewed the documentation filed by Aqua NC for rate case expense as listed in the affidavit of Gearhart. The Public Staff contended that while it does not dispute that the Company has provided documentation supporting the expenses listed in the affidavit, due to the magnitude of the expenses, in particular the legal fees from the rate case proceeding in the amount of $417,876, the Public Staff maintains its previously stated position that all rate case expenses should be amortized over a five-year period to mitigate the impact to customers.

The Commission has weighed the facts and specific circumstances of this case and concludes that the appropriate and reasonable amortization period for regulatory commission expense should be four years, except for the depreciation study amortization period which should remain at five years, as proposed by Aqua NC and the Public Staff, which is consistent with prior Commission orders.

Aqua NC's initial proposal to amortize rate case expenses over three years is consistent with prior practice, and the Commission specifically does not by this ruling reject the standard practice. The Public Staff's proposal, revised from its original position in its supplemental testimony, to apply a five-year amortization period to Aqua NC's regulatory commission expenses in this case, is, for the most part, a recognition of the significantly increased costs of this case, driven by the parties' exercise of their right to fully litigate these significant issues. Aqua NC's revised proposal for a four-year amortization period presented in its proposed order is viewed by the Commission as a compromise position by the Company based upon the unique circumstances of this case.

The costs of defense of any proceeding before this Commission are influenced in great measure by two factors: the vigor of the opposition of the consumer advocates and other intervenors, and the extent of the possibility of settlement of some or all of the contested issues. In this case, costs were clearly driven by a vigorous application of Public Staff resources on behalf of the ratepayers, whether measured by personnel, by amount or complexity of discovery, or by the sheer scope of the investigation, in terms of the duration of the period of examination. Similarly, the Company mounted an extensive and committed effort to contest and litigate a full slate of issues before this Commission. This case was unlike Aqua NC's last litigated rate case proceeding, being Docket No. W-218, Sub 319, which evidentiary hearing lasted approximately three days, or any other water and wastewater litigation before this Commission in recent memory. The present proceeding illustrates the proposition that parties are entitled to try their cases. Furthermore, the evidentiary hearing in this present proceeding included seven days of hearings scattered over the course of 11 business days. The hearing began on September 11, 2018 and, due to the impacts of Hurricane Florence[1] and other previously-calendared Commission hearings and commitments in September, concluded on September 25, 2018. There are costs to such

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[1] Hurricane Florence made landfall over Wrightsville Beach, North Carolina on Friday, September 14, 2018. In preparation for the hurricane, the hearing was adjourned midday on September 12, 2018 and was reconvened the morning of September 18, 2018.

undertakings, and so long as such costs are reasonably incurred, they should be recoverable in a timely fashion.

The Commission is also mindful of the testimony that suggests that the length of the interval since Aqua NC's last case (four years) is an anomaly, and that – given the magnitude of current and planned expenditures on water quality improvements – the interval until the next rate case may not be of such duration. Specifically, the Company suggested that its WSIC expenditures will cap in about three years. However, in recognition of the significantly increased costs of this case, driven by the parties' exercise of their right to fully litigate the significant issues involved in this particular proceeding, the Commission in of the opinion that a four-year amortization period for rate case expense is an appropriate compromise based upon the facts and circumstances of this proceeding.

Therefore, in this case, for good cause shown, and without suggesting a change to the standard three-year amortization period, the Commission concludes based on the evidence presented in this proceeding that it is reasonable and appropriate to utilize a four-year amortization period for all allowable rate case related costs, as recommended by Aqua NC in its proposed order, except for the depreciation study which should be amortized over five years, as proposed by the Company and the Public Staff.

Communications Initiative

Public Staff witness Cooper testified that Aqua NC applied for rate case expenses including what the Company describes as a Communications Initiative totaling $133,000. She testified that the Public Staff removed from rate case expense the $133,000 estimate which included $58,000 to The Paige Group and $75,000 for Aqua Efforts – Customer Education and Mailings. She testified these expenses were not incurred during the test year and, although the communications contain information on Aqua NC's water quality plans, these are Aqua NC self-promotional communications. She further testified the timing of the mailings suggests that the purpose was to promote a more positive image of Aqua NC going into the customer hearings in this rate proceeding. She testified Aqua NC's retention of a public relations firm to develop the mailings, which easily could have been developed in-house, further demonstrates the mailings were primarily for public relations purposes. She further testified it is not appropriate for customers to pay for expenses associated with Aqua NC's self-promotion.

Public Staff witness Cooper testified that Aqua NC filed this rate increase Application on March 7, 2018. The informational mailings to all Aqua NC water customers were sent on February 19, 2018. She testified subsequent mailings were sent to Raleigh area subdivisions that had experienced Aqua service issues, including Brayton Park, Brandon Station, Stillwater Landing, Stonehenge, Wildwood Green, and Coachman's Trail, in June 2018 prior to the June 25, 2018, Commission public witness hearing in Raleigh.

Public Staff witness Cooper testified while the mailings provided some information useful to customers, the Aqua NC website www.ncwaterquality.com has useful customer information and customers could be directed to this useful website information by regular customer bill notations or regular billing inserts. She testified even if Aqua NC deemed the letters appropriate for a mailing, the Company could have included the letters as a monthly billing insert at a lower cost.

Aqua NC witness Becker testified on rebuttal that he agreed that the entirety of the Communications Initiative should not be included in rate case expense, but he believes the entire amount should be recoverable, with 50% as rate case expense and 50% as a line-item in cost of service. He testified Aqua NC's communications plan is directly related to its Water Quality Plan. He testified Aqua NC is pressing forward with a water quality operations program that is utilizing a combination of increased capital and operational process improvements to address water quality. He testified Aqua NC's ability to educate and communicate with Aqua NC's customers on this issue is a critical piece of the success of the program.

Aqua NC witness Becker testified the specific functions performed by the consulting firm The Paige Group included the following:

- Developed www.ncwaterquality.com content for each section of the website.
- Developed a letter to all Aqua NC customers mailed in February 2018 announcing the Company's water quality improvement plan/approach and directing customers to the website.
- Developed 18 distinct letters to customers within various Aqua NC systems that have been most engaged with Aqua NC on secondary water quality issues. The letters outlined any improvement work already completed in each system, discussed any future planned work, and directed customers to the water quality website. All letters issued in June 2018.
- Developed a bill insert in June/July 2018 directing all customers to the water quality website.
- Developed two e-newsletters (one issued in June and another issued in August) to customers that signed up to receive updates on the water quality website.
- Developed a customer "print on the run" (POTR, similar to a bill insert), issued in August directing customers to the water quality website.

He testified all of these communications are designed to direct customers to the information on Aqua NC's Water Quality Plan, which is found at www.ncwaterquality.com. He further testified the materials are essential to efforts to educate Aqua NC customers, both about infrastructure investment, the necessity and components of rate increases, and in particular about secondary water quality issues.

Aqua NC witness Becker concluded rebuttal stating that Aqua NC's recommendation is that the Communications Initiative expenses be recoverable either as rate case expenses or as an expense line item.

On cross-examination, Aqua NC witness Becker testified The Paige Group conducted an Aqua NC survey to understand what customers want to see, how they want to see it, where they want to see it, and how often they want to see it. He testified The Paige Group designed Aqua NC's water quality website, but website updates would be necessary at less cost. He further testified some of the future communications could be prepared by Aqua NC in-house personnel, but Aqua NC intended to utilize The Paige Group or another consultant going forward on customer communications. Witness Becker also testified that the actual Communications Initiative cost was $83,000, instead of the $133,000 estimate that Aqua NC provided the Public Staff.

After carefully evaluating the evidence, including the agreement reached between Aqua NC and the Public Staff on this issue, the Commission concludes that the actual costs of $83,940 for the Communications Initiative are not rate case expenses as the information provided to customers does not educate the customers on rate case issues. The Commission concludes that the Communications Initiative expenses are reasonable operating expenses to educate customers on water quality issues. The Commission concludes that as the $83,940 includes the completed Aqua NC customer survey and the completed design of Aqua NC's water quality website, the reasonable ongoing expenses will be reduced. The Commission concludes that one half of the $83,940 expense, which is $41,970, should be amortized over three years thereby providing the reasonable ongoing annual expense of $13,990 to be included in the operating expenses, as stipulated.

Annualization/Consumption Factor

In his direct testimony, Public Staff witness Junis testified that updating the test year billing data to the 12-month period ending June 30, 2018, resulted in a higher level of bills than reflected in the originally filed application for the 12-month test year period ending September 30, 2017. He stated that he had adjusted the consumption for the updated data using a three-year average (July 2015 through June 2018) compared to only using the 12 months ended June 30, 2018. According to witness Junis, the consumption adjustment resulted in a 0.47% decrease for Aqua NC Water, a 1.85% decrease for Aqua NC Sewer, a 1.21% increase for Brookwood Water, a 2.97% increase for Fairways Water, and a 0.91% decrease for Fairways Sewer to reflect the difference between the test year per customer usage and the three-year average for the period ended June 30, 2018.

Witness Junis further testified that using the data in his billing analysis exhibit updated through June 30, 2018, Public Staff witness Henry calculated the growth and consumption factors referred to in his testimony. In addition, witness Junis stated that he recommended that Public Staff witness Henry apply the growth and consumption factors to the sewer and water short-term variable expenses identified by the EFC. (EFC Report, pp. 6 and 11) The exceptions were for sludge removal, purchased wastewater treatment, and purchased water expenses. Witness Junis stated that the sludge removal expense was calculated by Public Staff witness Darden to be the annual average of the updated two-year period ending June 2018, which includes recent growth and changes in consumption. According to witness Junis, short-term variability of the purchased wastewater treatment and purchased water expenses are almost entirely matched by variability of the commodity revenues of those systems.

Aqua NC witness Gearhart disagreed with the Public Staff's annualization and consumption adjustments. According to witness Gearhart, the purpose of this adjustment is to update variable expenses to match Aqua NC's period-end (June 30, 2018) customer count using a calculated "Annualization Factor" along with a "Consumption Factor" that is calculated using current consumption levels versus Aqua NC's three-year average consumption. Witness Gearhart further stated that the methodology to apply these factors has been consistently applied over Aqua

NC's last two rate cases; however, the Public Staff has changed from its prior methodology in three areas, as follows:

1. <u>The "Consumption Factor" has been applied in this case to Aqua NC's two Sewer Rate Divisions; whereas the consumption factor should only apply to Aqua NC's three Water Rate Divisions.</u>

Witness Gearhart testified that in Aqua NC's two previous rate cases (Docket Nos. W-218, Sub 319 and W-218, Sub 363), the consumption factor was not applied to either the Aqua NC Sewer or Fairways Sewer rate entities. According to witness Gearhart, the variable expenses for these sewer entities is primarily customer driven, while the consumption factor is designed to apply to only water rate entities.[1]

Further, witness Gearhart stated that, as a result, on Cooper Exhibit I, Schedule 3-5(a)(1), the Consumption Factor on line 2 for Aqua NC Sewer, should be changed from -1.85% to 0.00% and that line 4 for Fairways Sewer should be changed from -0.91% to 0.00%.

2. <u>Adjustments for Sludge Hauling expense that have been part of the annualization calculation in each of Aqua NC's last two rate cases (Docket Nos. W-218, Sub 319 and W-218, Sub 363) have been excluded from the annualization calculation in this rate proceeding.</u>

Company witness Gearhart stated that Public Staff witness Junis recommended that an annualization and consumption adjustment should be applied to items identified as short-term variable expenses by the EFC study, filed with the Commission on March 31, 2016, in Docket No. W-218, Sub 363A. <u>See</u> pages 6 and 11. Nonetheless, he testified that witness Junis specifically excludes sludge hauling expense, which is recommended for inclusion in the calculation by the EFC study on page 6 and included in the prior Public Staff rate case calculations mentioned above.

Witness Gearhart further stated that, despite Aqua NC's disagreement with the Public Staff's position concerning the ongoing level of sludge hauling expense calculated by Public Staff witness Darden and contested in Aqua NC witness Pearce's rebuttal testimony, the annualization factor is a separate calculation to take the historic balances (or averages) and annualize them for current end-of-period customer counts.

According to witness Gearhart, sludge hauling is the removal of wastewater solids from a WWTP. The increase in wastewater based on the Company's current customer count (as of

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[1] In response to Question 1 of Public Staff EDR 60 (entered in the record in this case as Public Staff Gearhart Rebuttal Cross-Examination Exhibit 1), witness Gearhart responded that:

> The basis for this contention was the fact that the consumption factor used in this adjustment is based on customer gallons billed. Applying that factor to sewer entitles where the vast majority of customers are flat rate and have no billed consumption would seem to be inappropriate.
>
> This factor has not been applied to sewer entitles for any Aqua NC rate cases dating back to at least 2007 and neither the company nor the Public Staff have disagreed on this concept.

June 30, 2018) will result in the requirement to remove more sludge material. Public Staff witness Junis excluded sludge hauling expense from his calculation, citing the fact that sludge hauling expense was calculated separately by the Public Staff to be the annual average of the two-year period ending June 2018. Witness Gearhart noted that the mid-point of these two years is June 2017. Since Aqua NC's total sewer customer count has increased by 4.2% since June 2017, witness Gearhart testified that this does not represent the expense levels that will be incurred using the current customer count at June 30, 2018. He stated that an average understates the actuality of an end-of-period number and undermines the intent of the annualization adjustment and the Company's opportunity to recover the costs associated with these customers.

Further, witness Gearhart stated that witness Junis' reasoning to selectively exclude an expense line that is directly related to customer counts from the annualization adjustment because it was separately updated using an average is flawed.

For the reasons stated, witness Gearhart requested that sludge hauling expense be added to the annualization adjustment calculation for this case, consistent with the practice in the Company's two prior rate cases.

On cross-examination by the Public Staff, witness Gearhart testified that, while he agreed that if water customers use less water, there would be less wastewater and less sludge produced, because only a small population of Aqua NC's sewer customers are metered sewer customers "...it isn't appropriate to apply the [consumption] adjustment to the entire population of the sewer rate entities ... both historically and logically, to the Company's way of thinking." Tr. Vol. 13, p. 109.

3. <u>Materials and Supplies Expense has been erroneously excluded from the Annualization and Consumption Adjustments despite being included in the previous two rate orders cited above.</u>

Witness Gearhart testified that materials and supplies expense is a variable expense where a large portion of the annual amounts increases with both the number of customers served and the level of annual consumption supported. Neither the Company nor the Public Staff has disputed this position in previous rate proceedings; however, witness Junis excluded these expenses from his annualization calculation. Witness Gearhart requested that materials and supplies expense be added to the annualization and consumption adjustment calculations for this case.

Witness Gearhart concluded by stating that witness Junis' exclusion of certain variable expenses effectively reduces revenues to which Aqua NC is entitled, and excludes legitimate costs associated with the number of customers which the Company serves as of June 30, 2018, at its current level of consumption. Per the Company's calculations, the impact of failing to apply the annualization and consumption adjustment factors to the three items enumerated above reduces the expenses which the Company is entitled to recover in this case.

Based upon the foregoing, the Commission concludes that the Public Staff's proposed consumption adjustment factors should not be applied to either Aqua NC's Sewer Operations rate division or the Company's Fairways Sewer Operations rate division. The consumption adjustment factors proposed by the Public Staff should only be applied to the Company's three Water

Operations rate divisions (Aqua NC Operations Water, Brookwood Operations Water, and Fairways Operations Water). Further, the Commission finds and concludes that Aqua NC's sludge hauling expense should be included in the calculation of the Company's annualization adjustment, whereas Aqua NC's materials and supplies expense should be excluded from the calculation.

The Commission reaches these conclusions for several reasons. First, the Commission finds the rebuttal testimony offered by Company witness Gearhart to be more persuasive on the annualization and consumption adjustment issues than the testimony offered by Public Staff witness Junis, except for the testimony by witness Gearhart concerning the inclusion of materials and supplies expense in the calculation of the annualization adjustment. The Commission gives more weight to the testimony of witness Junis concerning that particular contested matter.

Second, a consumption adjustment factor was not applied to either of the Aqua NC Sewer Rate Divisions in the Company's two prior rate cases and the Commission does not find good cause to depart from that treatment in this case. The Commission gives substantial weight to Aqua NC witness Gearhart's argument that the Public Staff's consumption factors used in these adjustments were based on the gallons billed for a small number of metered sewer customers and the factors were applied to sewer entities where the vast majority of the sewer customers are flat rate customers that have no billed consumption. The Commission concludes that such calculations would be inappropriate and would not result in reasonable consumption adjustments for Aqua NC's sewer rate entities.

Third, the annualization adjustment for sludge hauling expense was applied in the Company's two prior rate cases. The Commission does not find good cause to depart from that treatment in this case. The Public Staff has not offered adequate justification in support of its proposal to convince the Commission to change precedent and exclude sludge hauling expense from the annualization adjustment in this case. The Commission agrees with witness Gearhart that the Public Staff's proposal to selectively exclude sludge hauling expense from the annualization adjustment because it was separately updated by use of a two-year average, is flawed and should be rejected.

Fourth, the Commission gives substantial weight to the fact that the EFC Report does not include materials and supplies expense as a variable expense in its analysis as pointed out by Public Staff witness Junis. Although witness Gearhart testified that materials and supplies expense is a variable expense "where a large portion of the annual amounts increases with both the number of customers served and the level of annual consumption", he did not provide any specific examples of the types of materials and supplies expense that Aqua NC incurs which are variable that would indicate that the EFC Report is incorrect in that regard.

Accordingly, for the reasons set forth above, the Commission finds and concludes that the Public Staff's proposed consumption adjustment factors should not be applied to either Aqua NC's Sewer Operations rate division or the Company's Fairways Sewer Operations rate division, and Aqua NC's sludge hauling expense should be included in the calculation of the Company's annualization adjustment whereas its materials and supplies expense should be excluded.

Summary Conclusion

Based on the foregoing, the Commission concludes that the appropriate level of O&M and G&A expenses for combined operations for use in this proceeding are as follows:

Item	Amount
Salaries and wages	$10,242,720
Employee pensions and benefits	3,077,822
Purchased water/sewer treatment	2,316,616
Sludge removal	559,382
Purchased power	3,570,667
Fuel for power production	26,809
Chemicals	1,521,967
Materials and supplies	505,720
Testing fees	946,373
Transportation	919,149
Contractual services-engineering	2,750
Contractual services-accounting	188,101
Contractual services-legal	196,144
Contractual services-other	4,330,817
Rent	309,942
Insurance	650,674
Regulatory commission expense	201,666
Miscellaneous expense	1,477,705
Interest on customer deposits	32,388
Annualization & Consumption Adj.	190,392
Total O&M and G&A expenses	$31,267,804

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 87-91

The evidence supporting these findings of fact is contained in the testimony of Public Staff witnesses Cooper and Junis and Company witnesses Gearhart and Becker. The Company's level of depreciation and amortization expense on its Application is $9,926,332. The Public Staff's recommended level of depreciation and amortization expense is $9,986,078 for a difference of $59,746.

With the Stipulation and revisions made by the Public Staff in its supplemental testimony and Revised Supplemental Cooper Exhibit I, the Company does not dispute the following Public Staff adjustments to depreciation and amortization expense:

Item	Amount
Adjustment for post-test year plant additions	$146,775
Update costs related to future customers	173
Update Mid South growth PAA to 6/30/18	1,647
Adjustment for Mountain Ridge AIA	2,500
Total	$151,095

Therefore, the Commission finds and concludes that the adjustments listed above, which are not contested, are appropriate adjustments to be made to depreciation and amortization expense in this proceeding.

Based on the testimony of Company witnesses Gearhart and Becker, the Company disagrees with the following Public Staff adjustments to depreciation and amortization expense:

Item	Amount
Adjustment for Neuse Colony WWTP CIAC	\$51,673[1]
Adjustment for meters and meter installations	(139,727)
Adjustment for excess capacity	(3,295)
Total	(\$91,349)

Neuse Colony WWTP CIAC

The Public Staff made an adjustment to reduce amortization expense by \$42,676 related to the CIAC collected towards the total capacity of the Neuse Colony WWTP and \$8,997 for the imputation of CIAC for the Buffalo Creek force main and pump station costs that Aqua NC did not collect from developers. As discussed elsewhere in this Order, the Commission has concluded that the adjustment recommended by the Public Staff to remove from rate base the CIAC collected by Aqua NC in the amount of \$1.497 million related to the Neuse Colony WWTP is not appropriate in this proceeding. Further, the Commission concluded that the adjustment for the imputation of CIAC for the Buffalo Creek force main and pump station costs should be \$218,999 rather than \$315,687. Therefore, the Commission concludes that the Public Staff's adjustment of \$8,997 should be adjusted to \$6,241 and that \$6,241 of amortization expense should be included in this proceeding.

Meters and Meter Installations

The Public Staff made an adjustment to remove \$139,727 of depreciation expense related to its removal of \$2,834,632 and \$1,399,522 in AMR meters and related installation costs from Plant in Service for Aqua NC Water Operations and Brookwood Water Operations. As discussed elsewhere in this Order, the Commission disagreed with the Public Staff's adjustments to remove these costs from Plant in Service. Therefore, the Commission concludes that the corresponding adjustment to remove \$139,727 of depreciation expense is inappropriate and should not be made in this proceeding.

[1] Comprised of \$42,676 related to the amortization of the \$1.497 million in CIAC plus \$8,997 in amortization expense related to the imputed CIAC in the amount of \$315,687. Due to an inadvertent error, the Public Staff reduced total amortization expense by the \$8,997 adjustment rather than increasing amortization expense as it intended.

Excess Capacity

The Public Staff made an adjustment to increase depreciation expense by $20,372 and amortization expense by $23,667 for excess capacity for the Carolina Meadows, The Legacy at Jordan Lake, and Westfall WWTPs. As discussed elsewhere in this Order, the Company contended that approximately $1.7 million of rehabilitation and upgrades that were made in 2018 for the Carolina Meadows WWTP should not be subject to an excess capacity adjustment because this would disallow 30.63% of the upgrade immediately after the investment is made by the Company. In the present Order, the Commission has concluded that 50% of the $1.7 million rehabilitation and upgrades should be included as part of the excess capacity adjustment and 50% should be included in rate base as a post-test year update. Therefore, the Commission concludes that the corresponding adjustment to increase depreciation expense by $28,890 and amortization expense by $23,667 related to the Carolina Meadows, The Legacy at Jordan Lake, and Westfall WWTPs is appropriate and should be made in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 92-95

The evidence supporting these findings of fact is contained in the testimony of Public Staff witnesses Henry and Cooper, and Company witness Gearhart. The following table summarizes the differences between the Company's level of other taxes and Section 338(h) adjustment from its Application and the amounts recommended by the Public Staff:

Item	Company Application	Public Staff	Difference
Property taxes	$635,463	$635,463	$0
Payroll taxes	779,805	788,065	8,260
Other taxes	308,886	308,886	0
Section 338(h) adjustment	(20,024)	(20,024)	0
Total	$1,704,130	$1,712,390	$8,260

With the Stipulation and revisions made by the Public Staff in its supplemental testimony and Revised Supplemental Cooper Exhibit I, the Company does not dispute any of the Public Staff adjustments to other taxes.

Therefore, the Commission finds and concludes that the adjustments listed above, which are not contested, are appropriate adjustments to be made to other taxes in this proceeding.

The difference in the level of payroll taxes is due to the differing levels of salaries and wages recommended by the Company and the Public Staff. Based on the conclusions reached elsewhere in this Order regarding the levels of salaries and wages, the Commission concludes that the appropriate level of payroll taxes for use in this proceeding is $789,484.

Summary Conclusion

Based on the foregoing, the Commission concludes that the appropriate level of other taxes for combined operations for use in this proceeding is as follows:

Item	Amount
Property taxes	$635,463
Payroll taxes	789,484
Other taxes	308,886
Section 338(h) adjustment	(20,024)
Total	$1,713,809

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 96-99

The evidence supporting these findings of fact is contained in the testimony of Public Staff witnesses Boswell, Henry, and Cooper, and Company witness Kopas.

The following summarizes the differences between the Company's level of regulatory fee and income taxes from its Application and the amounts recommended by the Public Staff:

Item	Company Application	Public Staff	Difference
Regulatory fee	$77,046	$79,174	$2,128
Deferred income taxes	(639,532)	(120,648)	518,884
State income taxes	186,463	295,538	109,075
Federal income taxes	1,266,088	2,006,711	740,623
Total	$890,065	$2,260,775	$1,370,710

With the Stipulation and revisions made by the Public Staff in its supplemental testimony and Revised Supplemental Cooper Exhibit 1 and in the testimony of witness Boswell and Boswell Revised Exhibit2, the Company agreed with the Public Staff's adjustment to deferred income tax of $120,648 to reflect the annual amortization of protected federal EDIT.

Regulatory Fee

The difference in the level of regulatory fee is due to the differing levels of revenues recommended by the Company and the Public Staff. Based on conclusions reached elsewhere in this Order regarding the levels of revenues, the Commission concludes that the appropriate level of regulatory fee for use in this proceeding is $79,174.

State Income Taxes

The difference in the level of state income taxes is due to the differing levels of revenues and expenses recommended by the Company and the Public Staff. Based on the conclusions reached elsewhere in this Order regarding the levels of revenues and expenses, the Commission concludes that the appropriate level of state income taxes for use in this proceeding is $272,043.

Federal Income Taxes

The difference in the level of federal income taxes is due to the differing levels of revenues and expenses recommended by the Company and the Public Staff. Based on the conclusions reached elsewhere in this Order regarding the levels of revenues and expenses, the Commission concludes that the appropriate level of federal income taxes for use in this proceeding is $1,847,171.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 100-104

The evidence in support of these findings of fact is contained in the testimony of Company witness Kopas, the testimony of Public Staff witness Boswell, the Stipulation filed in this docket, and the entire record in this proceeding.

On December 22, 2017, the Tax Act was signed into law. Among other provisions, the Tax Act reduced the federal corporate income tax rate from 35% to 21%, effective January 1, 2018.[1] It also repealed the manufacturing tax deduction and eliminated bonus depreciation.

When the federal corporate income tax rate is reduced, as it was in the Tax Act, a portion of the accumulated deferred income tax that the utility has accumulated from the ratepayers will never be needed by the utility for the payment of taxes. This portion is classified as federal EDIT. The IRC requires that certain EDIT must be normalized, or flowed back, subject to certain limitations. Federal EDIT that is subject to this limitation is classified as protected federal EDIT. All other types of federal EDIT are termed unprotected, in that there are no limitations placed upon them by the IRS with regard to the length of time over which they may be returned to ratepayers.

In its Application, the Company reflected tax expense at the reduced federal corporate income tax rate of 21%. Aqua NC witness Kopas recommended in his direct testimony that the overcollection of federal taxes related to the reduction in the federal corporate income tax rate to income earned after January 1, 2018 be returned to customers over a one-year period as a credit beginning when the new base rates are implemented to reflect the new income tax rate.

Further, in the revised direct testimony of Company witness Kopas filed on August 6, 2018, the Company proposed to return federal protected EDIT to ratepayers over a period of time equal to the expected lifespan of the plant, property and equipment with which they are associated (based on the average rate assumption method (ARAM) as required by the IRS), return federal unprotected EDIT to ratepayers over 20 years, and return state EDIT to ratepayers over four years.

In testimony filed on September 5, 2018, Public Staff witness Boswell presented the Public Staff's proposal regarding the flowback of federal and state EDIT. She included four adjustments based on the information provided by the Company. First, she recommended the return of

[1] In response to the enactment of the Tax Act, on January 3, 2018, the Commission opened a rulemaking docket (Docket No. M-100, Sub 148, i.e., the Tax Docket) for the purpose of determining how the Commission should proceed. In the Order establishing the Tax Docket, the Commission placed certain public utilities on notice that the federal corporate income tax expense component of all existing rates and charges, effective January 1, 2018, would be billed and collected on a provisional rate basis.

protected federal EDIT based upon the Company's calculation of the net remaining life of the timing differences, as required under the IRC. For unprotected federal EDIT, she recommended removing the federal EDIT regulatory liability associated with the unprotected differences from rate base, and placing it in a rider to be refunded to ratepayers over three years on a levelized basis, with carrying costs. Witness Boswell stated that immediate removal of unprotected federal EDIT from rate base increases the Company's rate base and mitigates regulatory lag that may occur from refunds of unprotected federal EDIT not contemporaneously reflected in rate base. Further, witness Boswell maintained that refunding the unprotected federal EDIT over three years allows the Company to properly plan for any future credit needs. For state EDIT related to House Bill 998 (HB 998) and addressed in Docket No. M-100, Sub 138, witness Boswell recommended returning that EDIT to customers through a levelized rider that would expire at the end of a three-year period. Finally, witness Boswell testified that the Public Staff does not oppose the Company's proposal to refund to ratepayers the overcollection of federal taxes related to the decrease in federal tax rates for the period beginning January 1, 2018, and corresponding interest, as a credit for a one-year period beginning when the new base rates become effective in the current docket.

On September 17, 2018, the Company and the Public Staff jointly filed a Stipulation. The Stipulation settles, among other items, the treatment of federal EDIT, state EDIT related to HB 998 and addressed in Docket No. M-100, Sub 138, and the overcollection of federal corporate income taxes related to the decrease in the federal corporate income tax rate for the period beginning January 1, 2018. The Stipulation specifically states in Section III, Paragraphs II, JJ, and KK, as follows:

> II. The Company agrees to accept the Public Staff's proposals for addressing the Federal Tax Cuts and Jobs Act (the Tax Act). The unprotected Federal EDIT created by enactment of the Tax Act will be returned to customers through a levelized rider that will expire at the end of a three-year period. The protected EDIT will be flowed back following the tax normalization rules utilizing the average rate assumption method (ARAM) required by IRC Section 203(e).
>
> JJ. The state EDIT that the Company recorded pursuant to the Commission's May 13, 2014 Order in Docket No. M-100, Sub 138 will be returned to customers through a levelized rider that will expire at the end of a three-year period.
>
> KK. The Stipulating Parties agree to the Company's proposal to refund to the ratepayers the overcollection of federal taxes related to the decrease in federal tax rates for the period beginning January 1, 2018, and corresponding interest, as a surcharge credit for a one-year period beginning when the new base rates become effective in the current docket.

The AGO stated in its post-hearing brief that ratepayers should promptly enjoy the benefits of Aqua NC's cost savings resulting from recent changes in the federal tax law. The AGO asserted that recent reductions in federal and state corporate income tax rates result in lower operating expenses for utilities, with a favorable impact on the cost of public utility service, and produce an excess accumulation of funds for deferred income taxes that may be returned to ratepayers. The AGO noted that the Commission determined in its recent Order in a generic proceeding that the issue of how to reflect the changes in federal tax rates in new utility rates would be determined for Aqua NC in this general rate case proceeding. See Order Addressing the Impacts of the Federal Tax Cuts and Jobs Act on Public Utilities in Docket No. M-100, Sub 148 issued on October 5, 2018, p. 69. The AGO stated that it supports rate adjustments to flow through the benefits of tax changes to ratepayers as soon as possible.

The AGO further noted that the changes in tax rates have five impacts on rates as proposed by Aqua NC or resolved by agreement between Aqua NC and the Public Staff:

1. Operating expenses will reflect the federal corporate income tax rate reduction from 35% to 21%;

2. The amount of tax expense that was overcollected in rates from January 1, 2018 until new rates take effect will be returned to ratepayers as a bill credit over a period of one year;

3. The excess accumulated deferred income taxes associated with the change in the North Carolina corporate income tax rate under HB 998 will be returned to ratepayers in a rider to rates over a three-year period;

4. The unprotected excess accumulated deferred income taxes associated with the reduction in the federal corporate income tax rate will be returned to ratepayers in a rider to rates over a three-year period; and

5. The protected excess deferred income taxes associated with the reduction in the federal corporate income tax rate will be returned to ratepayers in rates over a period of 20 plus years reflecting the period required by federal tax provisions.

See p. 9 of Stipulation filed on September 17, 2018.

The AGO maintained that it supports the prompt adjustment of rates to reflect the tax reductions both through the reduction in operating expenses and the return of excess deferred income taxes. The AGO noted that in the recent Duke Energy Carolinas rate case in Docket No. E-7, Sub 1146, the AGO recommended a return of excess deferred taxes over a period of two years or less, so that ratepayers are able to benefit as soon as possible from the amounts they are owed.[1] The AGO asserted that although two years is preferable, in light of the resolution of the issue as proposed by Aqua NC and the Public Staff, the AGO does not oppose the return of excess deferred taxes over a three-year period under the circumstances of this case.

[1] See p. 141 of the AGO's post-hearing brief filed on April 27, 2018 in Docket No. E-7, Sub 1146.

WATER AND SEWER – RATE INCREASE

Based upon all of the evidence of record in this case, the Commission finds it appropriate to accept the Stipulation by the Company and the Public Staff concerning the tax issues. Therefore, the following will be accepted and approved by the Commission in this proceeding:

1. The Company's revenue requirement shall reflect the reduction in the federal corporate income tax rate from 35% to 21%, on the Company's ongoing federal income tax expense.

2. The Company's protected federal EDIT shall be flowed back to customers following the tax normalization rules utilizing the ARAM as required by the rules of the IRS.

3. The Company's unprotected federal EDIT shall be returned to ratepayers through a levelized rider over a period of three years.

4. The Company shall refund to its ratepayers the overcollection of federal income taxes related to the decrease in the federal corporate income tax rate for the period beginning January 1, 2018, and corresponding interest, through a surcharge credit for a one-year period beginning when the new base rates become effective in the current docket.

5. The Company's state EDIT recorded pursuant to the Commission's Order Addressing the Impacts of HB 998 on North Carolina Public Utilities issued May 13, 2014, in Docket No. M-100, Sub 138 shall be returned to ratepayers through a levelized rider that will expire at the end of a three-year period.

Finally, both the Company and the Public Staff included the same language in their respective proposed orders in this docket to specify that if new base rates are not established prior to completion of the refund to customers related to the levelized rider established for the flowback of excess deferred income taxes (approximately thirty-six months) the Company will file new tariffs for any rate division whose rates exceed the initial increase requested in the Application. The Company and the Public Staff also stated that the new base rates will be implemented the first month after the credit expires. They further provided language to state that the sole purpose of any new tariffs implemented at the time the rider for unprotected federal EDIT expires is to reduce the rates approved in Docket No. W-218, Sub 497 to a level no greater than the amount noticed for each rate division in that docket. The language states that there will be no deferral for recovery of the difference between the originally approved amount and the amount resulting from the new tariffs. Since it appears the Company and the Public Staff agree to this language, the Commission finds it appropriate to approve such language for inclusion in this Rate Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 105-113

The evidence supporting these findings of fact and conclusions is contained in the Company's Application and corresponding NCUC Form W-1, the testimony and exhibits of the public witnesses, the testimony and exhibits of Company witness D'Ascendis, Public Staff witness Hinton, the Stipulation, and the entire record of this proceeding.

Rate of Return on Equity

In its Application and in the direct testimony of Aqua NC witness Dylan D'Ascendis, the Company requested approval for its rates to be set using a rate of return on equity of 10.90%. In his rebuttal testimony, witness D'Ascendis reduced his recommended rate of return on equity to 10.80% after removing his adjustment for flotation cost. For the reasons set forth herein, the Commission finds that a rate of return on equity of 9.70% is just and reasonable.

Rate of return on equity, also referred to as the cost of equity capital, is often one of the most contentious issues to be addressed in a rate case. In the absence of a settlement agreed to by all parties, the Commission must exercise its independent judgment and arrive at its own independent conclusion as to all matters at issue, including the rate of return on equity. See, e.g., State ex rel. Utils. Comm'n v. Carolina Utils. Customers Ass'n, 348 N.C. 452, 466, 500 S.E.2d 693, 707 (1998). In order to reach an appropriate independent conclusion regarding the rate of return on equity, the Commission should evaluate the available evidence, particularly that presented by conflicting expert witnesses. State ex rel. Utils. Comm'n v. Cooper, 366 N.C. 484, 491-93, 739 S.E.2d 541, 546-47 (2013) (Cooper I). In this case, the evidence relating to the Company's cost of equity capital was presented by Aqua NC witness D'Ascendis and Public Staff witness Hinton. No other rate of return on equity expert evidence was presented by any party.

In addition to its evaluation of the expert evidence, the Commission must also make findings of fact regarding the impact of changing economic conditions on customers when determining the proper rate of return on equity for a public utility. Cooper I, 366 N.C. at 494, 739 S.E.2d at 548. This was a factor newly announced by the Supreme Court in its Cooper I decision and not previously required by the Commission or any appellate courts as an element that must be considered in connection with the Commission's determination of an appropriate rate of return on equity. The Commission's discussion of the evidence with respect to the findings required by Cooper I is set out in detail in this Order.

Cooper I was the result of the Supreme Court's reversal and remand of the Commission's approval of the agreement regarding the rate of return on equity in a stipulation between the Public Staff and Duke Energy Carolinas, LLC (DEC) in Docket No. E-7, Sub 989. The Commission has had occasion to apply both prongs of Cooper I in subsequent orders, specifically the following:

- Order Granting General Rate Increase, Docket No. E-2, Sub 1023 (May 30, 2013) (2013 DEP Rate Order), which was affirmed by the North Carolina Supreme Court in State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 444, 761 S.E.2d 640 (2014) (Cooper III)[1];

- Order on Remand, Docket No. E-7, Sub 989 (Oct. 23, 2013) (DEC Remand Order), which was affirmed by the North Carolina Supreme Court in State

[1] An intervening case, State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 430, 758 S.E.2d 635 (2014) (Cooper II), arose from Dominion North Carolina Power's 2012 rate case and resulted in a remand to the Commission, inasmuch as the Commission's Order in that case predated Cooper I.

ex rel. Utils. Comm'n v. Cooper, 367 N.C. 644, 766 S.E.2d 827 (2014) (Cooper IV);

- Order Granting General Rate Increase, Docket No. E-7, Sub 1026 (Sep. 24, 2013), which was affirmed by the Supreme Court in State ex rel. Utils. Comm'n v. Cooper, 367 N.C. 741, 767 S.E.2d 305 (2015) (Cooper V);

- Order on Remand, Docket No. E-22, Sub 479 (July 23, 2015), which was not appealed to the Supreme Court;

- Order Approving Rate Increase and Cost Deferrals and Revising PJM Regulatory Conditions, Docket No. E-22, Sub 532 (Dec. 22, 2016);

- Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase, Docket No. E-2, Sub 1142 (Feb. 23, 2018); and

- Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, Docket No. E-7, Sub 1146 (June 22, 2018).

In order to give full context to the Commission's decision herein and to elucidate its view of the requirements of the General Statutes as they relate to rate of return on equity, as interpreted by the Supreme Court in Cooper I, the Commission deems it important to provide in this Order an overview of the general principles governing this subject.

A. Governing Principles in Setting the Rate of Return on Equity

First, there are, as the Commission noted in the 2013 DEP Rate Order, constitutional constraints upon the Commission's rate of return on equity decisions established by the United States Supreme Court Decisions in Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679 (1923) (Bluefield), and Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944) (Hope):

> To fix rates that do not allow a utility to recover its costs, including the cost of equity capital, would be an unconstitutional taking. In assessing the impact of changing economic conditions on customers in setting an return on 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. State ex rel. Utilities Commission v. General Telephone Co. of the Southeast, 281 N.C. 318, 370, 189 S.E.2d 705, 757 (1972). As the Supreme Court held in that case, these factors constitute "the test of a fair rate of return" in Bluefield and Hope. Id.

2013 DEP Rate Order, p. 29.

Second, the rate of return on equity is, in fact, a cost. The return that equity investors require represents the cost to the utility of equity capital. In his dissenting opinion in Missouri ex rel. Southwestern Bell Tel. Co. v. Missouri Pub. Serv. Comm'n, 262 U.S. 276 (1923), Justice Brandeis remarked upon the lack of any functional distinction between the rate of return on equity (which he referred to as a "capital charge") and other items ordinarily viewed as business costs, including operating expenses, depreciation, and taxes:

> Each is a part of the current cost of supplying the service; and each should be met from current income. When the capital charges are for interest on the floating debt paid at the current rate, this is readily seen. But it is no less true of a legal obligation to pay interest on long-term bonds ... and it is also true of the economic obligation to pay dividends on stock, preferred or common.

Id. at 306 (Brandeis, J. dissenting) (emphasis added). Similarly, the United States Supreme Court observed in Hope, "From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business ... [which] include service on the debt and dividends on the stock." Hope at 603.

Leading academic commentators also define rate of return on equity as the cost of equity capital. Professor Charles Phillips, for example, states that "the term 'cost of capital' may be defined as the annual percentage that a utility must receive to maintain its credit, to pay a return to the owners of the enterprise, and to ensure the attraction of capital in amounts adequate to meet future needs." Phillips, Charles F., Jr., The Regulation of Public Utilities (Public Utilities Reports, Inc. 1993), p. 388. Professor Roger Morin approaches the matter from the economist's viewpoint:

> While utilities enjoy varying degrees of monopoly in the sale of public utility services, they must compete with everyone else in the free open market for the input factors of production, whether it be labor, materials, machines, or capital. The prices of these inputs are set in the competitive marketplace by supply and demand, and it is these input prices which are incorporated in the cost of service computation. This is just as true for capital as for any other factor of production. Since utilities must go to the open capital market and sell their securities in competition with every other issuer, there is obviously a market price to pay for the capital they require, for example, the interest on capital debt, or the expected return on equity.
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> [T]he cost of capital to the utility is synonymous with the investor's return, and the cost of capital is the earnings which must be generated by the investment of that capital in order to pay its price, that is, in order to meet the investor's required rate of return.

Morin, Roger A., Utilities' Cost of Capital (Public Utilities Reports, Inc. 1984), at pp. 19-21. Professor Morin adds: "The important point is that the prices of debt capital and equity capital are set by supply and demand, and both are influenced by the relationship between the risk and return expected for those securities and the risks expected from the overall menu of available securities." Id. at 20 (emphasis added).

Changing economic circumstances as they impact Aqua NC's customers may affect those customers' ability to afford rate increases. For this reason, customer impact weighs heavily in the overall ratemaking process, including, as set out in detail elsewhere in this Order, the Commission's own decision of an appropriate authorized rate of return on equity. In addition, in the event of a settlement, customer impact no doubt influences the process by which the parties to a rate case decide to settle contested matters and the level of rates achieved by any such settlement.

However, a customer's ability to afford a rate increase has absolutely no impact upon the supply of or the demand for capital. The economic forces at work in the competitive capital market determine the cost of capital – and, therefore, the utility's required rate of return on equity. The cost of capital does not go down because some customers may find it more difficult to pay for an increase in water and wastewater prices as a result of prevailing adverse economic conditions, any more than the cost of capital goes up because some customers may be prospering in better times.

Third, the Commission is and must always be mindful of the North Carolina Supreme Court's command that the Commission's task is to set rates as low as possible consistent with the dictates of the United States and North Carolina Constitutions. State ex rel. Utils. Comm'n v. Pub. Staff-N. Carolina Utils. Comm'n, 323 N.C. 481, 490, 374 S.E.2d 361, 370 (1988). Further, and echoing the discussion above concerning the fact that rate of return on equity represents the cost of equity capital, the Commission must execute the Supreme Court's command "irrespective of economic conditions in which ratepayers find themselves." (2013 DEP Rate Order, p. 37.) The Commission noted in that Order:

> The Commission always places primary emphasis on consumers' ability to pay where economic conditions are difficult. By the same token, it places the same emphasis on consumers' ability to pay when economic conditions are favorable as when the unemployment rate is low. Always there are customers facing difficulty in paying utility bills. The Commission does not grant higher rates of return on equity when the general body of ratepayers is in a better position to pay than at other times, which would seem to be a logical but misguided corollary to the position the Attorney General advocates on this issue.

Id. Indeed, in Cooper I the Supreme Court emphasized "changing economic conditions" and their impact upon customers. Cooper I, at 548.

Fourth, while there is no specific and discrete numerical basis for quantifying the impact of economic conditions on customers, the impact on customers of changing economic conditions is embedded in the rate of return on equity expert witnesses' analyses. The Commission noted this in the 2013 DEP Rate Order: "This impact is essentially inherent in the ranges presented by the return on equity expert witnesses, whose testimony plainly recognized economic conditions – through the use of econometric models – as a factor to be considered in setting rates of return." 2013 DEP Rate Order, p. 38.

Fifth, under long-standing decisions of the North Carolina Supreme Court, the Commission's subjective judgment is a necessary part of determining the authorized rate of return on equity. State ex rel. Utils. Comm'n v. Pub. Staff, 323 N.C. 481, 490, 374 S.E.2d 361, 369 (1988). As the Commission also noted in the 2013 DEP Rate Order:

> Indeed, of all the components of a utility's cost of service that must be determined in the ratemaking process, the appropriate [rate of return on equity] the one requiring the greatest degree of subjective judgment by the Commission. Setting a return on equity [rate of return on equity] for regulatory purposes is not simply a mathematical exercise, despite the quantitative models used by the expert witnesses. As explained in one prominent treatise,
>
>> Throughout all of its decisions, the [United States] Supreme Court has formulated no specific rules for determining a fair rate of return, but it has enumerated a number of guidelines. The Court has made it clear that confiscation of property must be avoided, that no one rate can be considered fair at all times and that regulation does not guarantee a fair return. The Court also has consistently stated that a necessary prerequisite for profitable operations is efficient and economical management. Beyond this is a list of several factors the commissions are supposed to consider in making their decisions, but no weights have been assigned.
>>
>> The relevant economic criteria enunciated by the Court are three: financial integrity, capital attraction and comparable earnings. Stated another way, the rate of return allowed a public utility should be high enough: (1) to maintain the financial integrity of the enterprise, (2) to enable the utility to attract the new capital it needs to serve the public, and (3) to provide a return on common equity that is commensurate with returns on investments in other enterprises of corresponding risk. These three economic criteria are interrelated and have been used widely for many years by regulatory commissions throughout the country in determining the rate of return allowed public utilities.

> In reality, the concept of a fair rate of return represents a "zone of reasonableness." As explained by the Pennsylvania commission:
>
> > There is a range of reasonableness within which earnings may properly fluctuate and still be deemed just and reasonable and not excessive or extortionate. It is bounded at one level by investor interest against confiscation and the need for averting any threat to the security for the capital embarked upon the enterprise. At the other level it is bounded by consumer interest against excessive and unreasonable charges for service.
>
> As long as the allowed return falls within this zone, therefore, it is just and reasonable. . . . It is the task of the commissions to translate these generalizations into quantitative terms.
>
> Charles F. Phillips, Jr., The Regulation of Public Utilities, 3d ed. 1993, pp. 381-82 (notes omitted).

2013 DEP Rate Order, pp. 35-36.

Thus, the Commission must exercise its subjective judgment so as to balance two competing rate of return on equity-related factors – the economic conditions facing the Company's customers and the Company's need to attract equity financing in order to continue providing safe and reliable service.

The Supreme Court in Cooper V affirmed the 2013 DEC Rate Order, in which this framework was fully articulated. But to the framework we can add additional factors based upon the Supreme Court's decisions in Cooper III, Cooper IV, and Cooper V. Specifically, the Supreme Court held that nothing in Cooper I requires the Commission to "quantify" the influence of changing economic conditions upon customers (see, e.g., Cooper V, 367 N.C. at 745-46; Cooper IV, 367 N.C. at 650; Cooper III, 367 N.C. at 450), and, indeed, the Supreme Court reiterated that setting the rate of return on equity is a function of the Commission's subjective judgment: "Given th[e] subjectivity ordinarily inherent in the determination of a proper rate of return on common equity, there are inevitably pertinent factors which are properly taken into account but which cannot be quantified with the kind of specificity here demanded by [the appellant]." Cooper III, 367 N.C. at 450, quoting State ex rel. Utils. Comm'n v. Pub. Staff-North Carolina Utils. Comm'n, 323 N.C. 481, 490 (1988).

Finally, the Supreme Court discussed with approval the Commission's reference to and reliance upon expert witness testimony that used econometric models that the Commission had noted "inherently" contained the effects of changing economic circumstances upon customers, and also discussed with approval the Commission's reference to and reliance upon expert witness testimony correlating the North Carolina economy with the national economy. See, e.g., Cooper V, 367 N.C. at 747; Cooper III, 367 N.C. at 451.

It is against this backdrop of overarching principles that the Commission turns to the evidence presented in this case.

B. Application of the Governing Principles to the Rate of Return Decision

1. Evidence from Expert Witnesses on Cost of Equity Capital

Company witness D'Ascendis recommended in his direct testimony a rate of return on equity of 10.90%. This 10.90% was based upon his indicated cost of common equity of 10.60%, a recommended size adjustment of 0.20% and a recommended flotation adjustment of 0.11%. He rounded down his cost of common equity with these adjustments to 10.90%. In his rebuttal testimony, witness D'Ascendis eliminated his adjustment for flotation costs and amended his recommended cost of equity to 10.80% for Aqua NC.

Witness D'Ascendis' recommendation was based upon his Discounted Cash Flow (DCF) model, his Risk Premium Model (RPM), and his Capital Asset Pricing Model (CAPM), applied to market data of a proxy group of eight publicly-traded water companies (Utility Proxy Group). He also applied the DCF, RPM, and CAPM to a proxy group of domestic, non-price regulated companies (Non-Price Regulated Proxy Group) which he described as comparable in total risk to the his Utility Proxy Group.

The results derived from witness. D'Ascendis' analyses in his direct testimony are as follows:

Summary of D'Ascendis' Common Equity Cost Rate Analyses

Utility Proxy Group	
Discounted Cash Flow Model	8.95%
Risk Premium Model	11.07
Capital Asset Pricing Model	10.39
Cost of Equity Models Applied to Non-Price Regulated Proxy Group	11.57
Indicated Common Equity Cost Rate Before Adjustments	10.60%
Size Adjustment	0.20
Flotation Cost Adjustment	0.11
Indicated Common Equity Cost Rate Cost Rate After Adjustments	10.91%
Recommended Common Equity Cost Rate After Adjustments	10.90%

Witness D'Ascendis concluded that a common equity cost rate of 10.60% for Aqua NC is indicated before any Company-specific adjustments. He then adjusted upward by 0.20% to reflect Aqua NC's smaller relative size as compared with the members of his Utility Proxy Group, resulting in a size-adjusted indicated common equity cost rate of 10.80%. As noted above, he also adjusted upward the indicated common equity cost rate by an additional 0.11% to reflect flotation costs in his direct testimony, but eliminated the 0.11% flotation cost adjustment in his rebuttal testimony.

Witness D'Ascendis testified he used the single-stage constant growth DCF model. He testified his unadjusted dividend yields are based on the proxy companies' dividends as of January 12, 2018, divided by the average of closing market prices for the 60 trading days ending January 12, 2018.[1] He made an adjustment to the dividend yield because dividends are paid periodically, usually quarterly.

For witness D'Ascendis' DCF growth rate, he testified he used only analysts' five-year forecasts of earning per share (EPS) growth. He testified the mean result of his application of the single-stage DCF model is 9.09%, the median result is 8.81%, and the average of the two is 8.95% for his Utility Proxy Group.

Aqua NC witness D'Ascendis used two risk premium methods. He testified his first method is the Predictive Risk Premium Model (PRPM), while the second method is a RPM using a total market approach. He testified that the inputs to his PRPM are the historical returns on the common shares of each company in the Utility Proxy Group minus the historical monthly yield on long-term U.S. Treasury securities through December 2017. He testified he added the forecasted 30-year U.S. Treasury Bond yield, 3.54% to each company's PRPM-derived equity risk premium to arrive at an indicated cost of common equity. He testified the mean PRPM indicated common equity cost rate for the Utility Proxy Group is 12.36%, the median is 12.09%, and the average of the two is 12.23%.

Witness D'Ascendis testified his total market approach RPM adds a prospective public utility bond yield to an average of (1) an equity risk premium that is derived from a beta-adjusted total market equity risk premium, and (2) an equity risk premium based on the S&P Utilities Index. He calculated his adjusted prospective bond yield for the Utility Proxy Group to be 4.84%, and the average equity risk premium to be 5.06% resulting in risk premium derived common equity to be 9.90% for his RPM using his total market approach.

To determine the results of his risk premium method, he testified that he averaged the PRPM result of 12.23% and the RPM results of 9.90% and the indicated cost of equity from his risk premium method was 11.07%.

For his CAPM, witness D'Ascendis testified he applied both the traditional CAPM and the empirical CAPM (ECAPM) to the companies in his Utility Proxy Group and averaged the results. For his CAPM beta coefficient, he considered two methods of calculation: the average of the Beta coefficients of the Utility Proxy Group companies reported by Bloomberg Professional Services, and the average of the Beta coefficients of the Utility Proxy Group companies as reported by Value Line resulting in a mean beta of .78 and a median beta of .74.

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[1] See Schedule DWD-3, page 1, column 1.

Witness D'Ascendis testified that the risk-free rate adopted for both applications of the CAPM is 3.54%. This risk-free rate of 3.54% is based on the average of the *Blue Chip* consensus forecast of the expected yields on 30-year U.S. Treasury bonds for the six quarters ending with the second calendar quarter of 2019, and long-term projections for the years 2019 to 2023 and 2024 to 2028.

Witness D'Ascendis stated that he used three sources of data to determine the risk premium in his CAPM: historical, Value Line, and Bloomberg, that when averaged, result in an average total market equity risk premium of 8.69%. He testified that the mean result of his CAPM/ECAPM analyses is 10.53%, the median is 10.25%, and the average of the two is 10.39%.

Witness D'Ascendis also selected 11 domestic non-price regulated companies for his Non-Price Regulated Proxy Group that he believes are comparable in total risk to his Utility Proxy Group. He calculated common equity cost rates using the DCF, RPM, and CAPM for the Non-Price Regulated Proxy Group. His DCF result was 13.37%, his RPM cost rate was 11.28%, and his CAPM/ECAPM cost rate was 10.91%.

Witness D'Ascendis also made a 0.20% equity cost rate adjustment due to Aqua NC's small size relative to the Utility Proxy Group. He testified that the Company has greater relative risk than the average company in the Utility Proxy Group because of its smaller size compared with the group, as measured by an estimated market capitalization of common equity for Aqua NC (whose common stock is not publicly-traded).

Public Staff witness Hinton recommended a common equity cost rate of 9.20%. Public Staff witness Hinton testified that, according to Moody's Bond Survey, yields on long-term "A" rated public utility bonds as of July 2018 were 4.27% as compared to 4.63% for January, 2014 which is the time of filing of the Public Staff and Company Stipulation in the last Aqua NC rate case (Sub 363) that included a 9.75% cost of equity. He further testified that the relative decrease in long-term bond yields since the last rate case is not indicative of an increase in financing costs for utilities; rather, it portends a lowering of financing costs for long-term capital. However, he testified that there has been an increase in the cost of short-term financing.

Witness Hinton stated that the current lower interest rates and stable inflationary environment of today indicate that borrowers are paying less for the time value of money. He testified that this is significant since utility stocks and utility capital costs are highly interest rate-sensitive relative to most industries. Furthermore, given that investors often view purchases of the common stocks of utilities as substitutes for fixed income investments, the reductions in interest rates observed over the past 10 years or more has paralleled the decreases in investor required rates of return on common equity.

Witness Hinton testified that he generally does not rely on interest rate forecasts. Rather, he believes that relying on current interest rates, especially in relation to yields on long-term bonds, is more appropriate for ratemaking in that, it is reasonable to expect that as investors are pricing bonds, they are based on expectations on future interest rates, inflation rates, etc. He testified that while he has a healthy respect for forecasting, he is aware of the risk of relying on predictions of rising interest rate cases. He presented a case that can be observed in the testimony of Company witness Ahern in the 2013 Aqua NC rate case. In that case, witness Ahern identified several point forecasts of 30-year Treasury Bond yields that were predicted to rise to 4.3% in 2015, 4.7% in 2016, and 5.2% in 2017. He presented a graph of 30-Year US Treasury Bonds yields which showed in 2016 the range was approximately 2.50% to 3.10%, and in 2017 the range was approximately 2.25% to 3.10%. Tr. 6, p. 175.

Witness Hinton testified he used the DCF model and the RPM to determine the cost of equity for the Company. He testified that the DCF model is a method of evaluating the expected cash flows from an investment by giving appropriate consideration to the time value of money. The DCF model is based on the theory that the price of the investment will equal the discounted cash flows of return. The return to an equity investor comes in the form of expected future dividends and price appreciation. He testified that as the new price will again be the sum of the discounted cash flows, price appreciation is ignored and attention focused on the expected stream of dividends.

Witness Hinton testified that he applied the DCF method to Aqua America and to a comparable group of water utilities followed by the Value Line Investment Survey (Value Line). He testified that the standard edition of Value Line covers nine water companies. He excluded Connecticut Water Service, Inc. and the SJW Group because of a merger of the two companies and also excluded Consolidated Water Co. because of its significant overseas operations.

Witness Hinton calculated the dividend yield component of the DCF by using the Value Line estimate of dividends to be declared over the next 12 months divided by the price of the stock as reported in the Value Line Summary and Index sections for each week of the 13-week period May 25, 2018 through August 17, 2018. He testified that a 13-week averaging period tends to smooth out short-term variations in the stock prices. This process resulted in an average dividend yield of 2.1% for his proxy group of water utilities.

To calculate the expected growth rate component of the DCF, Public Staff witness Hinton employed the growth rates of his proxy group in EPS, dividends per share (DPS), and book value per share (BVPS) as reported in Value Line over the past 10 and five years. He also employed the forecasts of the growth rates of his proxy group in EPS, DPS, and BVPS as reported in Value Line. He testified that the historical and forecast growth rates are prepared by analysts of an independent advisory service that is widely available to investors, and should also provide an estimate of investor expectations. He testified that he included both historical known growth rates and forecast growth rates, because it is reasonable to expect that investors consider both sets of data in deriving their expectations.

Witness Hinton incorporated the consensus of various analysts' forecasts of five-year EPS growth rate projections as reported in Yahoo Finance. He testified that the dividend yields and growth rates for each of the companies and for the average for his comparable proxy group are shown in Exhibit JRH-3.

Witness Hinton concluded based upon his DCF analysis that a reasonable expected dividend yield is 2.1% with an expected growth rate of 6.1% to 7.1%. Thus, he testified that his DCF analysis produces a cost of common equity for his comparable proxy group of water utilities of 8.20% to 9.20%.

Witness Hinton testified that the equity risk premium method can be defined as the difference between the expected return on a common stock and the expected return on a debt security. The differential between the two rates of return are indicative of the return investors require in order to compensate them for the additional risk involved with an investment in the Company's common stock over an investment in the Company's bonds that involves less risk.

Witness Hinton testified that his method relies on approved returns on common equity for water utility companies from various public utility commissions as reported in a RRA Water Advisory, published by the Regulatory Research Associates, Inc. (RRA), a group within S&P Global Market Intelligence (RRA Water Advisory). In order to estimate the relationship with a representative cost of debt capital, he regressed the average annual allowed equity returns with the average Moody's A-rated yields for Public Utility bonds from 2006 through 2018. His regression analysis, which incorporates years of historical data, is combined with recent monthly yields to provide an estimate of the current cost of common equity.

Witness Hinton testified that the use of allowed returns as the basis for the expected equity return has two strengths over other approaches that involve various models that estimate the expected equity return on common stocks and subtracting a representative cost of debt. He stated that one strength of his approach is that authorized returns on equity are generally arrived at through lengthy investigations by various parties with opposing views on the rate of return required by investors. He testified that it is reasonable to conclude that the approved allowed returns are good estimates of the cost of equity.

Witness Hinton testified that the summary data of risk premiums shown on his Exhibit JRH-4, page 1 of 2, indicates that the average risk premium is 4.95% with a maximum premium of 5.78% and minimum premium of 3.73%, which when combined with the last six months of Moody's A-rated utility bond yields produces yields with an average cost of equity of 9.11%, a maximum cost of equity of 9.94%, and a minimum cost of equity of 7.89%. He performed a statistical regression analysis as shown on Exhibit JRH-4, page 2 of 2 in order to quantify the relationship of allowed equity returns and bond costs. He testified that by applying the allowed returns to the current utility bond cost of 4.16%, resulted in a risk premium of 5.53%, and a cost of equity of current estimate of the equity risk premium of equity of 9.69%.

Witness Hinton concluded that based on all of the results of his DCF model that indicate a cost of equity from 8.20% to 9.20% with a central point estimate of 8.70%, and the risk premium model that indicates a cost of equity of 9.69%, he determined that the investor required rate of return on equity for Aqua NC is between 8.70% and 9.69%. He concluded that 9.20% is his single best estimate of the Company's cost of common equity.

Witness Hinton testified as to the reasonableness of his recommended return, that he considered the pre-tax interest coverage ratio produced by his cost estimates for the cost of equity.

He testified that based on his recommended capital structure, cost of debt, and equity return of 9.20%, the pre-tax interest coverage ratio is approximately 3.7 times. He testified that this tax interest coverage should allow Aqua NC to qualify for a single "A" bond rating.

Witness Hinton testified that his recommended return on common equity takes into consideration the impact of the water and sewer system improvement charges pursuant to N.C.G.S. § 62-113.12 on the Company's financial risk. He testified that these improvement charges are seen by debt and equity investors as supportive regulation that mitigates business risk. Witness Hinton stated that he believes that this mechanism is noteworthy and is supportive of his 9.20% return on equity recommendation.

Witness Hinton testified that it is not appropriate to add a risk premium to the cost of equity due to the size of the company. He testified that from a regulatory policy perspective, ratepayers should not be required to pay higher rates because they are located in the franchise area of a utility of a size which is arbitrarily considered to be small. He further testified if such adjustments were routinely allowed, an incentive would exist for large existing utilities to form subsidiaries when merging or even to split-up into subsidiaries to obtain higher allowed returns. He further testified that Aqua NC operates in a franchise environment that insulates the Company from competition and it operates with procedures in place that allow for rate adjustments for eligible capital improvements, cost increases, and other unusual circumstances that impact its earnings.

Witness Hinton observed that Aqua NC is owned 100% by Aqua America. A potential investor cannot purchase Aqua NC stock. All Aqua NC paid in equity capital is infused by Aqua America. He testified that, as stated in the testimony of Aqua NC company witness D'Ascendis, Aqua America is the second largest investor owned water and wastewater utility in the United States with its shares traded on the New York Stock Exchange (NYSE) and had a $6.9 billion market capitalization at the January 12, 2018, market close as reported by Value Line. He testified that Aqua America's market capitalization of $6.9 billion is larger than the cumulative market capitalization of the next four largest investor owned water utilities. These four are American States Water Co. (NYSE), California Water Service Group (NYSE), SJW Group (NYSE), and Connecticut Water Service, Inc. (NASDAQ).

In his rebuttal testimony, Aqua NC witness D'Ascendis disagreed with witness Hinton that a 9.20% common equity rate is appropriate for Aqua NC and stated that the Public Staff's recommendation would not be sufficient to maintain the integrity of presently invested capital and permit the attraction of needed new capital at a reasonable cost in competition with other firms of comparable risk.

Witness D'Ascendis also disagreed with witness Hinton's exclusion of the CAPM and comparable earnings model (CEM), both of which witness Hinton used as a check on his DCF and RPM in a previous proceeding involving Aqua NC (Docket No. W-218, Sub 319). According to witness D'Ascendis, both the academic literature and the Commission support the use of multiple models in determining a return on common equity. Witness D'Ascendis then attempted to supplement what would have been witness Hinton's analysis with a CAPM and CEM, which indicated results of 11.02% and 12.23%, respectively.

Witness D'Ascendis objected to witness Hinton's DCF analysis and he also took issue with witness Hinton's use of historical growth rates in EPS, DPS and BVPS as well as his use of projected growth rates in DPS and BVPS. He asserted that it is appropriate to rely exclusively upon security analysts' forecasts of EPS growth rates in a DCF analysis for multiple reasons.

First, he believed that individual investors who could potentially invest in utility stocks generally have more limited informational resources than institutional investors and are therefore likely to place greater significance on the opinions and projections expressed by financial information services such as Value Line, Reuters, Zacks, and Yahoo! Finance, which are all easily accessible and/or available on the Internet and through public libraries. Witness D'Ascendis testified that security analysts have significant insight into the dynamics of the industries and individual companies they analyze, as well as company's abilities to effectively manage the effects of a changing industry, economic or market environment. Second, over the long run, there can be no growth in DPS without growth in EPS. Security analysts' earnings expectations have a more significant, but not exclusive, influence upon market prices than dividend expectations, providing a better matching between investors' market price appreciation expectation and the growth component of the DCF model. Third, there is academic support for the superiority of analysts' forecasts of growth in EPS as the growth component in the DCF model. Witness D'Ascendis asserted that witness Hinton should have relied exclusively upon the Value Line and Yahoo! Finance EPS forecasts.

Witness D'Ascendis also disagreed with witness Hinton's application of his RPM because of his use of annual average authorized returns on equity for water companies instead of using individual cases and his use of current interest rates instead of projected interest rates. According to witness D'Ascendis, using current or historical measures, such as interest rates, are inappropriate for cost of capital and ratemaking purposes because they are both prospective in nature.

In addition, witness D'Ascendis disagreed with witness Hinton on risk due to size. Witness D'Ascendis emphasized that because it is the rate base of a specific regulated jurisdictional utility to which a regulatory allowed rate of return will be applied, it is the unique risk of that rate base which needs to be reflected in the allowed rate of return, including any additional risk due to small size. In addition, the corporate structure of the owners of that rate base is irrelevant as it is the use of the funds which gives rise to the investment risk, not the source of those funds. It matters not whether the rate base is held privately, by a municipality, by a large holding company, by a small holding company, by an equity investment fund, multiple shareholders or a single shareholder. Only the riskiness of the particular rate base is relevant. The size of any given jurisdictional rate base is not arbitrary, it is what it is, and it is imminently relevant relative to the size of any publicly traded utilities from whose market data a common equity cost rate recommendation is derived. Therefore, there is no incentive for "large existing utilities to form subsidiaries when merging or even to split-up into subsidiaries" because it is the risk of the regulated rate base which is relevant.

Witness D'Ascendis testified that witness Hinton's corrected cost of common equity analysis results in a common equity cost rate of 10.57% for witness Hinton's comparable group of water utilities before adjustment for Aqua NC's increased risk due to size relative to the proxy group.

On cross-examination, witness D'Ascendis testified he was aware that 99% of Aqua NC's customers were residential and that Aqua NC's systems were geographically diversified across North Carolina including Ashe County, the Hendersonville area, the Charlotte area, the Greensboro and the Winston-Salem areas, the Raleigh area, the Fayetteville area, and also the Atlantic Coast from New Hanover County to Carteret County. He testified Aqua NC has approximately 100,000 customers in North Carolina and that there is not a regulated water company in North Carolina anywhere near Aqua NC's size.

Witness D'Ascendis testified that Public Staff D'Ascendis Cross-Examination Exhibit 1 showed at the market close on September 7, 2018, as listed in the Morningstar investment publication, Aqua America's market capitalization was at $6.65 billion, which was greater than the combined market capitalizations of the next four largest water companies. He further testified that SCANA Corporation (SCANA) had a market capitalization of $5.22 billion which is less than Aqua America's $6.65 billion, and that SCANA is the parent company and owner of 100% of the common stock of South Carolina Electric and Gas (SCE&G), and Public Service Company of North Carolina, Inc. (PSNC). He also testified an investor could not buy stock in the Company, and instead would buy the stock of Aqua America.

Witness D'Ascendis testified on cross-examination that Public Staff D'Ascendis Cross-Examination Exhibit 2 was his response to a Public Staff data request showing water and wastewater utility general rate cases in which he testified recommending a return on equity range or a specific return on equity. He testified in the United Utility Services Company general rate case in South Carolina with a decision in December 2013. In that case, he recommended a return on equity range of 10.45% to 11.45% which had a mid-point of 10.95%, and the Commission approved a 9.35% return on equity which was 160 basis points below his mid-point.

Witness D'Ascendis testified that in the Carolina Water Service, Inc. general rate case in South Carolina, with a decision on December 22, 2015, he recommended a return on equity range of 10.00% to 10.50% which had a mid-point of 10.25%, and the Commission approved a return on equity of 9.34% which was 91 basis points below his mid-point. He further testified in the Aqua Illinois, Inc. general rate case in Illinois with decision on March 2, 2018. In that case, he recommended a specific return on equity of 10.85%, and the Commission approved a return on equity of 9.60%, which was 125 basis points below his recommendation.

Witness D'Ascendis testified in the Middlesex Water Company general rate case in New Jersey with decision on March 6, 2018, and recommended a specific return on equity of 10.70%. The Commission approved a return on equity of 9.60%, which was 110 basis points below his recommendation. He testified that in the current Aqua Virginia, Inc. general rate case, Aqua Virginia recently agreed in a settlement to a 9.25% return on equity, which the Hearing Examiner accepted. Witness D'Ascendis recommended a specific return on equity of 10.60%, and the

Hearing Examiner accepted 9.25% return on equity which was 135 basis points below his specific recommendation.

Witness D'Ascendis testified that most of the authorized returns on equity on Public Staff D'Ascendis Direct Cross-Examination Exhibit 2 were the result of settlements which the Commission approved. He testified there were only three general rate cases with litigated returns on equity: Columbia Water Company in Pennsylvania where in January 2014, with the Commission approved return on equity of 9.75% being 160 basis points below his recommended specific return on equity of 11.35%; Emporium Water Company in Pennsylvania where the Commission in January 2015, approved a 10.00% return on equity, which was 105 basis points below his recommended specific return on equity of 11.05%; and Carolina Water Service, Inc. in South Carolina where on May 26, 2018, the Commission approved return on equity of 10.50% which was within his range of 10.45% to 10.95%. He testified that this South Carolina decision is the most recent litigated return on equity and he considered it the most relevant.

Witness D'Ascendis testified that Public Staff Direct Cross-Examination Exhibit 3 is a RRA Water Advisory, dated July 27, 2018, which lists water utility rate case decisions in the years 2014 through 2017, and through June 30, 2018. He testified that in 2018 through June 30, 2018, the average approved return on equity was 9.41%. He testified that the four 2018 California return on equity decisions have fully forecasted test years, full decoupling, and three year rate plans. He testified that these California decisions dated March 22, 2018, were all fully litigated. The approved returns on equity were: California America Water with 9.20% approved return on equity, California Water Service with 9.20% approved return on equity, Golden State Water Co. with 8.90% approved return on equity, and San Jose Water Co. with 8.90% approved return on equity. He testified that more relevant was the recent Duke Energy Carolinas case Docket No. E-7, Sub 1146 with a settlement that approved a 9.90% return on equity.

Witness D'Ascendis further testified in 2014 where the RRA Water Advisory reported 13 Commission decisions with approved returns on equity, none were 10.00% or above. He testified in 2015 where the RRA Water Advisory reported 11 Commission decisions with approved return on equites, only two were 10.00% or above, being Maryland American Water at 10.00% and Kona Water in Hawaii with 10.10% return on equity. He testified in 2016 where the RRA Water Advisory reported nine Commission decisions with approved returns on equity, only Hawaii Water Service at 10.10% return on equity, had an approved return on equity at 10.0% or above. He testified in 2017 where the RRA Water Advisory reported nine Commission decisions with approved returns on equity, only Utilities, Inc. of Florida with a formula approved return on equity of 10.40% and a 41.92% approved common equity capital structure, had an approved return on equity at 10.00% or above.

Witness D'Ascendis further testified on cross-examination that the four California water utilities with the litigated March 22, 2018, 8.90% and 9.20% return on equity decisions, and Middlesex Water with the March 24, 2018 decision, are companies included in his Utility Proxy Group, with Golden State Water being a subsidiary of American States Water.

2. Evidence of Impact of Changing Economic Conditions on Customers

WATER AND SEWER – RATE INCREASE

As noted above, utility rates must be set within the constitutional constraints made clear by the United States Supreme Court in Bluefield and Hope. To fix rates that do not allow a utility to recover its costs, including the cost of equity capital, would be an unconstitutional taking. In assessing the impact of changing economic conditions on customers in setting a return on equity, the Commission must nonetheless provide the public utility with the opportunity, by sound management, to (1) produce a fair profit for its shareholders, in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital. State ex rel. Utils. Comm'n v. General Telephone Co. of the Southeast, 281 N.C. 318, 370, 189 S.E.2d 705 (1972). As the Supreme Court held in that case, these factors constitute "the test of a fair rate of return" in Bluefield and Hope. Id.

a. Discussion and Conclusions Regarding Evidence Introduced During the Evidentiary Hearing

In this case, all parties had the opportunity to present the Commission with evidence concerning changing economic conditions as they affect customers. The testimony of witnesses D'Ascendis and Hinton, which the Commission finds entitled to substantial weight, addresses changing economic conditions.

As to the impact of changing economic conditions on Aqua NC's customers, Public Staff witness Hinton testified he reviewed information on the economic conditions in the areas served by Aqua NC, specifically, the 2014, 2015, and 2016 data on total personal income from the Bureau of Economic Analysis (BEA) and the Development Tier Designations published by the North Carolina Department of Commerce for the counties in which Aqua NC's systems are located. The BEA data indicates that from 2014 to 2016, total personal income weighted by the number of water customers by county grew at a compound annual growth rate (CAGR) of 3.20%, which is slightly lower than the rate of 3.40% for the whole State.

Witness Hinton testified the North Carolina Department of Commerce annually ranks the State's 100 counties based on economic well-being and assigns each a Tier designation. The most distressed counties are rated a "1" and the most prosperous counties are rated a "3". The rankings examine several economic measures such as, household income, poverty rates, unemployment rates, population growth, and per capita property tax base. For 2017, the average Tier ranking that has been weighted by the number of water customers by county is 2.6. He testified that both these economic measures indicate that there has been improvement in the economic conditions for Aqua NC's service area relative to the 2013 rate case.

Aqua NC witness D'Ascendis testified on economic conditions in North Carolina that he reviewed. He testified he reviewed: unemployment rates from the United States, North Carolina, and the counties comprising Aqua NC's service territory; the growth in Gross National Product (GDP) in both the United States and North Carolina; median household income in the United States and in North Carolina; and national income and consumption trends.

He testified that the rate of unemployment has fallen substantially in North Carolina and the U.S. since late 2009 and early 2010, when the rates peaked at 10.00% and 11.30%, respectively.

He testified that by December 2017, the unemployment rate had fallen to less than one-half of those peak levels: 4.10% nationally; and 4.50% in North Carolina.

He testified that he was also able to review (seasonally unadjusted) unemployment rates in the counties served by Aqua NC. At its peak, which occurred in late 2009 into early 2010, the unemployment rate in those counties reached 12.52% (52 basis points higher than the Statewide average); by December 2017 it had fallen to 4.48% (8 basis points higher than the Statewide average).

Witness D'Ascendis testified that for real Gross Domestic Product growth, there also has been a relatively strong correlation between North Carolina and the national economy (approximately 69%). Since the financial crisis, the national rate of growth at times (during portions of 2010 and 2012) outpaced North Carolina. He testified that since the third quarter of 2015, however, North Carolina has consistently exceeded the national growth rate.

Witness D'Ascendis testified as to median household income, the correlation between North Carolina and the U.S. is relatively strong (approximately 88% from 2005 through 2015). Since 2009 (that is, the years subsequent to the financial crisis), median household income in North Carolina has grown at a faster annual rate than the national median income (3.62% vs. 2.47%).

Witness D'Ascendis noted that in the Commission's Order on Remand in Docket No. E-22, Sub 479, the Commission observed that economic conditions in North Carolina were highly correlated with national conditions, such that they were reflected in the analyses used to determine the cost of common equity. He testified that those relationships still hold: Economic conditions in North Carolina continue to improve from the recession following the 2008/2009 financial crisis, and they continue to be strongly correlated to conditions in the U.S., generally. He testified unemployment, at both the State and county level, continues to fall and remains highly correlated with national rates of unemployment; real Gross Domestic Product recently has grown faster in North Carolina than the national rate of growth, although the two remain fairly well correlated; and median household income also has grown faster in North Carolina than the rest of the country, and remains strongly correlated with national levels.

b. Evidence Introduced During Public Hearings and Further Conclusions

The Commission's review also includes consideration of the evidence presented during the public hearings by public witnesses, almost all of whom presently are customers of Aqua NC. The hearings provided 28 witnesses the opportunity to be heard regarding their respective positions on Aqua NC's Application to increase rates. The Commission held four evening hearings throughout Aqua NC's service territory to receive public testimony. The testimony presented at the hearings illustrates the difficult economic conditions facing many North Carolina citizens. The Commission accepts as credible, probative, and entitled to substantial weight, the testimony of the public witnesses.

c. Commission's Decision Setting Rate of Return and Approving Rate Increase Takes Into Account and Ameliorates the Impact of Current Economic Conditions on Customers

As noted above, the Commission's duty under N.C.G.S. § 62-133 is to set rates as low as reasonably possible without impairing the Company's ability to raise the capital needed to provide reliable water and wastewater service and recover its cost of providing service. The Commission is especially mindful of this duty in light of the evidence in this case concerning the impact of current economic conditions on customers.

Chapter 62 of the North Carolina General Statutes in general, and N.C.G.S. § 62-133 in particular, set forth an elaborate formula the Commission must employ in establishing rates. The rate of return on cost of property element of the formula in N.C.G.S. § 62-133(b)(4) is a significant, but not independent one. Each element of the formula must be analyzed to determine the utility's cost of service and revenue requirement. The Commission must make many subjective decisions with respect to each element in the formula in establishing the rates it approves in a general rate case. The Commission must approve accounting and pro forma adjustments to comply with N.C.G.S. § 62-133(b)(3). The Commission must approve depreciation rates pursuant to N.C.G.S. § 62-133(b)(1). The decisions the Commission makes in each of these subjective areas have multiple and varied impacts on the Decisions it makes elsewhere in establishing rates, such as its decision on rate of return on equity.

Economic conditions existing during the test year, at the time of the public hearings, and at the date of this Commission Order affect not only the ability of Aqua NC's consumers to pay water and wastewater utility rates, but also the ability of Aqua NC to earn the authorized rate of return during the period rates will be in effect. Pursuant to N.C.G.S. § 62-133, rates in North Carolina are set based on a modified historic test period.[1] A component of cost of service as important as return on investment is test year revenues.[2] 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.

When costs and expenses grow at a faster pace than revenues during the period when rates will be in effect, the utility will experience a decline in its realized rate of return on investment to a level below its authorized rate of return. Differences exist between the authorized return and the earned, or realized, return. Components of the cost of service must be paid from the rates the utility charges before the equity investors are paid their return on equity. Operating and administrative expenses must be paid, depreciation must be funded, taxes must be paid, and the utility must pay interest on the debt it incurs. To the extent revenues are insufficient to cover the entire cost of service, the shortfall reduces the return to the equity investor, last in line to be paid. When this occurs, the utility's realized, or earned, return is less than the authorized return.

This phenomenon, caused by incurrence of higher costs prior to the implementation of new rates to recover those higher costs, is commonly referred to as regulatory lag. Just as the Commission confronts constitutional and statutory restrictions in making discrete decrements to rate of return on equity to mitigate the impact of rates on consumers, it also confronts statutory constraints on its ability to adjust test year revenues to mitigate for regulatory lag. However, the

[1] N.C.G.S. § 62-133(c).

[2] N.C.G.S. § 62-133(b)(3).

WSIC and SSIC legislation N.C.G.S. § 62-133.12 and Commission Rules R7-39 and R10-26, have mitigated the regulatory lag for Aqua NC. The Commission, in its expert experience and judgment and based on evidence in the record, is aware of the effects of regulatory lag in the existing economic environment. However, just as the Commission is constrained to address difficult economic times on customers' ability to pay for service by establishing a lower rate of return on equity in isolation from the many subjective determinations that must be made in a general rate case, it likewise does not address the effect of regulatory lag on the Company by establishing a higher rate of return on equity. Instead, in setting the rate of return, the Commission considers both of these negative impacts in its ultimate decision fixing Aqua NC's rates. The Commission keeps all factors affected by current economic conditions in mind in the many subjective decisions it makes in establishing rates. In doing so in the case at hand, the Commission approved the 9.70% rate of return on equity in the context of weighing and balancing numerous factors and making many subjective decisions. When these decisions are viewed as a whole, including the decision to establish the rate of return on equity at 9.70%, the Commission's overall decision fixing rates in this general rate case results in lower rates to consumers in the existing economic environment.

Consumers pay rates, a charge in dollars per 1,000 gallons for the water they consume and a monthly flat rate for residential wastewater customers. Investors are compensated by earning a return on the capital they invest in the business. Consumers do not pay a rate of return on equity.

All of the scores of adjustments the Commission approves reduce the revenues to be recovered from ratepayers and the return to be paid to equity investors. Some adjustments reduce the authorized rate of return on investment financed by equity investors. The adjustments are made solely to reduce rates and provide rate stability to consumers (and return to equity investors) to recognize the difficulty for consumers to pay in the current economic environment. While the equity investor's cost was calculated by resort to a rate of return on equity of 9.70% instead of 10.80%, this is only one approved adjustment that reduced ratepayer responsibility and equity investor reward. Many other adjustments reduced the dollars the investors actually have the opportunity to receive. Therefore, nearly all of these other adjustments reduce ratepayer responsibility and equity investor returns in compliance with the Commission's responsibility to establish rates as low as reasonably permissible without transgressing constitutional constraints.

For example, to the extent the Commission makes downward adjustments to rate base, or disallows test year expenses, or increases test year revenues, or reduces the equity capital structure component, the Commission reduces the rates consumers pay during the future period when rates will be in effect. Because the utility's investors' compensation for the provision of service to consumers takes the form of return on investment, downward adjustments to rate base or disallowances of test year expenses or increases to test year revenues, or reduction in the equity capital structure component, reduce investors' return on investment irrespective of its determination of rate of return on equity.

The rate base, expenses, and revenue adjustments are instances where the Commission makes decisions in each general rate case, including the present case, that influence the Commission's determination on rate of return on equity and cost of service and the revenue requirement. The Commission always endeavors to comply with the North Carolina Supreme Court's requirements that it "fix rates as low as may be reasonably consistent" with

U.S. Constitutional requirements irrespective of economic conditions in which ratepayers find themselves. While compliance with these requirements may have been implicit and, the Commission reasonably assumed, self-evident as shown above, the Commission makes them explicit in this case to comply with the Supreme Court requirements of Cooper I.

Based on the changing economic conditions and their effects on Aqua NC's customers, the Commission recognizes the financial difficulty that the increase in the Company's rates will create for some of Aqua NC's customers, especially low-income customers. As shown by the evidence, relatively small changes in the rate of return on equity have a substantial impact on a utility's base rates. Therefore, the Commission has carefully considered the changing economic conditions and their effects on Aqua NC's customers in reaching its decision regarding the Company's approved rate of return on equity. The Commission also recognizes that the Company is investing significant sums in system improvements to serve its customers, thus requiring the Company to maintain its creditworthiness in order to compete for large sums of capital on reasonable terms. The Commission must weigh the impact of changing economic conditions on Aqua NC's customers against the benefits that those customers derive from the Company's ability to provide safe, adequate, and reliable water and wastewater service. Safe, adequate, and reliable water and wastewater service is essential to the well-being of Aqua NC's customers.

The Commission finds and concludes that these investments by the Company provide significant benefits to Aqua NC's customers. The Commission concludes that the return on equity approved by the Commission in this proceeding appropriately balances the benefits received by Aqua NC's customers from Aqua NC's provision of safe, adequate, and reliable water and wastewater service with the difficulties that some of Aqua NC's customers will experience in paying Aqua NC's increased rates.

The Commission in every case seeks to comply with the North Carolina Supreme Court mandate that the Commission establish rates as low as possible within constitutional limits. The adjustments the Commission approves in this case comply with that mandate. Nearly all of them reduced the requested return on equity and benefit consumers' ability to pay their bills in this economic environment.

d. Summary and Conclusions on the Rate of Return on Equity

The Commission has carefully evaluated the return on equity testimony of Aqua NC witness D'Ascendis and Public Staff witness Hinton. The results of each of the models or methods used by these two witnesses to derive the return on equity that each witness recommends is shown below:

	D'Ascendis	Hinton
Utility Proxy Group		
DCF	8.95%	8.70%
Risk Premium	11.07%	9.69%
CAPM	10.39%	-----
Non-Price Regulated Proxy Group		
Using DCF, Risk Premium, and CAPM	11.57%	
Indicated Return on Equity Before Adjustment	10.60%	9.20%
Size Adjustment	0.20%	-------
Recommended Return on Equity	10.80%	9.20%

The range of these results is 8.70% to 11.57%. Further, underlying the low result of 8.70% is a range of 8.20% to 9.20%, according to witness Hinton's testimony concerning his application of the DCF. Similarly, underlying the high result of 11.57% is a range of 10.91% (CAPM) to 13.37% (DCF), according to witness D'Ascendis' testimony concerning the cost of equity models applied to his Non-Price Regulated Proxy Group. Such a wide range of estimates by expert witnesses is not atypical in proceedings before the Commission with respect to the return on equity issue. Neither is the seemingly endless debate and habitual differences in judgment among expert witnesses on the virtues of one model or method versus another and how to best determine and measure the required inputs of each model in representing the interest of their intervening party. Nonetheless, the Commission is uniquely situated, qualified and required to use its impartial judgment to determine the return on equity based on the testimony and evidence in this proceeding in accordance with the legal guidelines discussed above.

In so doing, the Commission finds and concludes that the testimony of Company witness D'Ascendis regarding the DCF and CAPM analyses of his Utility Proxy Group and the risk premium analysis testimony of Public Staff witness Hinton are credible, probative, and are entitled to substantial weight.

Company witness D'Ascendis, noting that Aqua NC is not publicly-traded, first established a group of eight relatively comparable risk water companies that are publicly-traded (Utility Proxy Group). He testified that use of the companies of relatively comparable risk companies as proxies is consistent with principles of fair rate of return established in the Hope and Bluefield cases, which are recognized as the primary standards for the establishment of a fair return for a regulated public utility. He then applied the DCF, the CAPM, and the risk premium models to the market data of the Utility Proxy Group. The average of his DCF result of 8.95% and CAPM result of 10.39% for his Utility Proxy Group is 9.67%. The Commission approved return on equity of 9.70% is thus supported by the 9.67% average of the results of witness D'Ascendis' application of the DCF and CAPM models.

Witness Hinton applied a risk premium analysis by performing a regression analysis using the allowed returns on common equity for water utilities from various public utility commissions, as reported in a RRA Water Advisory, with the average Moody's A-rated bond yields for public utility bonds from 2006 through 2018. The results of the regression analysis were combined with recent monthly yields to provide the current cost of equity. According to witness Hinton, the use of allowed returns as the basis for the expected equity return has strengths over other (risk premium) approaches that estimate the expected equity return on equity and subtract a representative cost of debt. He testified that one strength of his approach is that authorized returns on equity are generally arrived at through lengthy investigations by various parties with opposing views on the rate of return required by investors. Thus, it is reasonable to conclude that the approved returns are good estimates for the cost of equity. Witness Hinton testified that applying the significant statistical relationship of the allowed equity returns and bond yields from the regression analysis and adding current bond cost of 4.16% resulted in a current estimate of the cost of equity of 9.69%, which again, is supportive of the Commission's approved return on equity of 9.70%.

Witness Hinton also applied the DCF model to a proxy risk group of publicly traded water utilities. To determine the expected growth rate component in his application of the DCF, witness Hinton testified that the employed both historical and forecasted growth rates of earnings per share (EPS), book value per share (BVPS), and dividends per share (DPS). He concluded that an expected growth rate of 6.10% to 7.10% should be combined with a dividend yield of 2.10% which produced his cost of equity estimate of 8.20% to 9.20% for his comparable risk group based on his DCF analysis. Witness Hinton testified that it was reasonable to expect that investors consider both historic and forecast growth rates in deriving their expectations. In contrast, witness D'Ascendis relied exclusively on analysts' forecasts of EPS growth. In rebuttal, he also testified that there is a significant body of empirical evidence supporting the superiority of using analysts' EPS growth rates in a DCF analysis. Witness D'Ascendis also testified in rebuttal that it is unclear how much weight witness Hinton gave to each of his projected and historical growth rates in arriving at his high and low growth estimates for his proxy risk group, because witness Hinton's range of growth rates bears no logical relationship to the array of growth rates that witness Hinton evaluated. The Commission notes that the higher end of witness Hinton's DCF estimate of 9.20%, based on a growth rate of 7.10% is actually close to witness D'Ascendis DCF estimate of 8.95% and deserving of some weight. However, given the conflicting evidence concerning whether the use of historic or forecasted growth rates is more appropriate, the lack of clarity as to how the growth rate range was determined, and all the evidence in the record in this proceeding, the Commission gives little weight to the lower end of witness Hinton's DCF result.

Witness D'Ascendis also used two risk premium methods to estimate the cost of equity to Aqua NC. He testified that his first method is the PRPM and the second method is a RPM using a total market approach. In his PRPM, he employed the Eviews© statistical software applied to the historical returns on the common shares of each company in his Utility Proxy Group minus the historical monthly yields on long-term U.S. Treasury securities through December 2017 to arrive at a predicted annual equity risk premium. He then added the forecasted 30-year U.S. Treasury security to each company's PRPM derived equity risk premium. Using this approach, he calculated a cost of equity estimate of 12.23%. In his total market approach RPM, he added a prospective public utility bond yield to an average of (1) an equity risk premium that is derived from a beta-adjusted total market equity risk premium, and (2) an equity risk premium based on the S&P Utilities Index. His RPM result produced a rate of return estimate of 9.90%. Averaging his PRPM result of 12.23% and his total market approach RPM, he determined that the cost of equity is 11.07% using his risk premium methods.

The Commission gives little weight to the risk premium testimony and result of 11.07% of witness D'Ascendis. The PRPM result of 12.23% is unreasonably high. Further, the Commission is skeptical that investor expectations are influenced by a method analyzing economic time series with time-varying volatility using the statistical software employed by witness D'Ascendis. However, the Commission does note that the total market approach RPM result of 9.90% derived by witness D'Ascendis is somewhat supportive of the Commission approved return on equity of 9.70%.

In addition to estimating the cost of equity for his Utility Proxy Group of publicly-traded water utilities, witness D'Ascendis attempted to estimate the cost of equity for another proxy group consisting of 11 domestic, non-price regulated companies. In order to select a proxy group of domestic, non-price regulated companies similar in risk to the Utility Proxy Group, he testified that he relied on the beta coefficients and related statistics derived from Value Line regression analyses of weekly market prices over the last five years. After selecting the 11 unregulated companies, he applied the DCF, RPM, and CAPM in the identical manner used for his Utility Proxy Group, with certain limited expectations. The results of the DCF, RPM, and CAPM applied to the non-price regulated proxy group are 13.37%, 11.28%, and 10.91%, respectively. The Commission concludes that these results are unreasonably high. Each of these results are higher than witness D'Ascendis' estimates of the cost of equity for his own Utility Proxy Group and deserve no weight, particularly with respect to the DCF. The Commission further concludes that given the difference in these results, the risk of the two groups is not equal and the Utility Proxy Group is more reliable as a proxy for the investment risk of common equity in Aqua NC.

After determining that the indicated cost of equity from the DCF, CAPM, and risk premium methods applied to both of his proxy groups equals 10.60%, witness D'Ascendis then adjusted the indicated cost of equity upward by 0.20% to reflect Aqua NC's smaller size compared to companies in his Utility Proxy Group. He testified that the size of the company is a significant element of business risk for which investors expect to be compensated through higher returns. Witness D'Ascendis calculated his size adjustment as described in his prefiled direct testimony and stated that even though a 2.89% upward size adjustment is indicated, he applies a 0.20% size premium to Aqua NC's indicated common equity cost rate. Witness Hinton testified that he does not believe it is appropriate to add a risk premium to the cost of equity of Aqua NC due to size for several reasons. First, from a regulatory policy perspective, witness Hinton stated that ratepayers should not be required to pay higher rates because they are located in the franchise area of a utility which is arbitrarily considered to be small. Further, if such adjustments were routinely allowed, an incentive would exist for large utilities to form subsidiaries or split-up subsidiaries to obtain higher returns. In addition, he noted that Aqua NC operates in a franchise environment that insulates the Company from competition with procedures in place for rate adjustments for circumstances that impact its earnings. He noted that Aqua NC is also owned by Aqua America, Inc., the second largest publicly-traded water utility in the United States. Finally, while witness Hinton stated that while there are studies that address how the small size of a company relates to higher returns, he is aware of only one study that focuses on the size of regulated utilities and risk and that study concluded that utility stocks do not exhibit a significant size premium. In rebuttal, witness D'Ascendis maintained that a small size adjustment was necessary based on the results of studies he cited and discussed and contended that the study concerning size premiums for utilities discussed by witness Hinton was flawed. He also testified that the fact that Aqua NC is a subsidiary of Aqua America, Inc. is irrelevant for ratemaking purposes because it is the rate base of Aqua NC to which the overall rate of return set in this proceeding will be applied which is consistent with the stand-alone nature of ratemaking.

Based upon the evidence in the record in this proceeding, the Commission concludes that a size adjustment of 0.20% is not warranted and should not be approved. It is not irrelevant that Aqua NC is a subsidiary of Aqua America. The Commission determines there is insufficient evidence to authorize an adjustment to the approved rate of return on equity in this case. The record simply does not indicate the extent to which Aqua NC's size alone justifies added risk. While a small water/wastewater utility might face greater risk than a publicly traded peer group, because for example the service area was confined to a hurricane prone coastal geographic area, evidence of such factual predicates is absent from the record. The Commission notes that the witnesses also disagreed with respect to whether the studies discussed in the testimony concerning size and risk are reliable or even applicable to regulated utilities. The Commission concludes that the testimony regarding these studies is not convincing and does not support a size adjustment. In addition, while witness D'Ascendis calculates and testifies that a 2.89% upward size adjustment is indicated, he applies a size premium of 0.20% to Aqua NC's indicated cost of equity. The Commission thus concludes that the 0.20% adjustment is not supported by his testimony and is rather arbitrary.

Having determined that the appropriate rate of return on equity based upon the evidence in this proceeding is 9.70%, the Commission notes that there was considerable discussion during the hearing concerning the authorized returns on equity for water utilities in other jurisdictions. While the Commission has relied upon the record in this proceeding and is certainly aware that returns in other jurisdictions can be influenced by many factors, such as different capital market conditions during different periods of time, settlements versus full litigation, the Commission concludes that the rate of return on equity trends and decisions by other regulatory authorities deserve some weight as (1) they provide a check or additional perspective on the case-specific circumstances, and (2) the Company must compete with other regulated utilities in the capital markets, meaning that a rate of return 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 significantly higher than other utilities of comparable risk would result in customers paying more than necessary. Public Staff D'Ascendis Cross-Examination Exhibit 3, the RRA Water Advisory publication showing approved return on equity decisions for water utilities across the country from January 2014 through June 30, 2018, is helpful. According to this exhibit, the average rate of return on equity for water utilities is 9.59% in 2014, 9.76% in 2015, 9.71% in 2016, 9.56% in 2017, and in the only seven cases reported on for the first six months of 2018 the average is 9.41% with a range of 8.9% to 10.5%. This authorized return data is generally supportive of the Commission approved return on equity of 9.70% based upon the evidence in this proceeding. To the extent it is not, the record evidence justifies any such difference.

In its post-hearing brief, the AGO notes that the 10.80% rate of return on equity requested by Aqua NC is substantially higher than the 9.75% return on equity stipulated to accept in its last general rate case in Docket No. W-218, Sub 363. In this case, the AGO, in its role as consumer advocate, argues that the DCF model is relied upon by investors using widely available current market data and the DCF results produced by expert witnesses for Aqua NC and the Public Staff show that a 9.2% return on equity is more than sufficient to attract the investment dollars needed for adequate service. However, unlike the AGO, the Commission cannot ignore the other evidence in this proceeding. When other such evidence is considered and weighed by the Commission as discussed hereinabove, the Commission finds and concludes that the reasonable and appropriate return on equity is 9.70%.

The Commission notes further that its approval of a rate of return on equity at the level of 9.70% or for that matter at any level, is not a guarantee to the Company that it will earn a rate of return on equity at that level. Rather, as North Carolina law requires, setting the rate of return on equity at this level merely affords Aqua NC the opportunity to achieve such a return. The Commission finds and concludes, based upon all the evidence presented, that the rate of return on equity provided for herein will indeed afford the Company the opportunity to earn a reasonable and sufficient return for its shareholders while at the same time producing rates that are just and reasonable to its customers.

<u>Capital Structure</u>

Aqua NC witness D'Ascendis recommended the use of a ratemaking capital structure consisting of 50.00% long-term debt and 50.00% common equity. He testified this capital structure is based on a test year capital structure for Aqua NC, ending September 30, 2017. He testified that a capital structure consisting of 50.00% long-term debt and 50.00% total equity is appropriate for ratemaking purposes for Aqua NC in the current proceeding because it is comparable, but conservative, to the average capital structure ratios (based on total permanent capital) maintained by the water companies in his Utility Proxy Group on whose market data he based his recommended common equity cost rate.

Public Staff witness Hinton also testified in recommending a 50.00% long-term debt and 50.00% common equity capital structure. The Stipulation also supports a 50.00% long-term debt, 50.00% common equity capital structure. No other party presented evidence as to a different capital structure.

Accordingly, the Commission finds and concludes that the recommended capital structure of 50.00% common equity and 50.00% long-term debt is just and reasonable to all parties in light of all the evidence presented.

<u>Cost of Debt</u>

In its Application, the Company proposed a long-term debt cost of 4.76%. The Stipulation provides for a 4.63% cost of debt. The Commission finds for the reasons set forth herein that a 4.63% cost of debt is just and reasonable.

Public Staff witness Hinton, in his supplemental testimony, supported the embedded cost of Aqua NC's long-term debt on June 30, 2018, of 4.63%. The 4.63% debt cost of the Stipulation gives customers the benefit of reductions in Aqua NC's lower cost of debt after the end of the test year.

No intervenor offered any evidence supporting a debt cost below 4.63%. The Commission, therefore, finds and concludes that the use of a debt cost of 4.63% is just and reasonable to all parties based upon all the evidence presented.

EVIDENCE AND CONCLUSION FOR FINDINGS OF FACT NOS. 114-115

The following schedules summarize the gross revenues and rate of return that the Company should have a reasonable opportunity to achieve based on the increases and decreases in revenues approved in this Order for each rate entity. These schedules, illustrating the Company's gross revenue requirements, incorporate the adjustments found appropriate by the Commission in this Order.

SCHEDULE I
Aqua North Carolina, Inc.
Docket No. W-218, Sub 497
Net Operating Income for a Return
For the Twelve Months Ended September 30, 2017
Combined Operations

	Present Rates	Increase Approved	After Approved Increase
Operating Revenues:			
Service revenues	$55,496,957	$2,916,600	$58,413,557
Late payment fees	114,830	6,240	121,070
Miscellaneous revenues	1,355,499	0	1,355,499
Uncollectibles & abatements	(414,248)	(26,820)	(441,068)
Total operating revenues	56,553,038	2,896,020	59,449,058
Operating Revenue Deductions:			
Salaries & wages	10,242,720	0	10,242,720
Employee pensions & benefits	3,077,822	0	3,077,822
Purchased water/sewer treatment	2,316,616	0	2,316,616
Sludge removal	559,382	0	559,382
Purchased power	3,570,667	0	3,570,667
Fuel for power production	26,809	0	26,809
Chemicals	1,521,967	0	1,521,967
Materials & supplies	505,720	0	505,720
Testing fees	946,373	0	946,373
Transportation	919,149	0	919,149
Contractual services-engineering	2,750	0	2,750
Contractual services-accounting	188,101	0	188,101
Contractual services-legal	196,144	0	196,144
Contractual services-other	4,330,817	0	4,330,817
Rent	309,942	0	309,942
Insurance	650,674	0	650,674
Regulatory commission expense	201,666	0	201,666
Miscellaneous expense	1,477,705	0	1,477,705
Interest on customer deposits	32,388	0	32,388
Annualization & consumption adjustments	190,392	0	190,392

Total O&M and G&A expense	31,267,804	0	31,267,804
Depreciation & amortization expense	10,076,409	0	10,076,409
Property taxes	635,463	0	635,463
Payroll taxes	789,484	0	789,484
Other taxes	308,886	0	308,886
Section 338(h) adjustment	(20,024)	0	(20,024)
Regulatory fee	79,174	4,054	83,228
Deferred income tax	(120,648)	0	(120,648)
State income tax	272,043	84,891	356,934
Federal income tax	1,847,171	576,413	2,423,584
Total operating revenue deductions	45,135,762	665,358	45,801,120
Net operating income for return	$11,417,276	$2,230,662	$13,647,938

SCHEDULE II
Aqua North Carolina, Inc.
Docket No. W-218, Sub 497
Original Cost Rate Base
For the Twelve Months Ended September 30, 2017
Combined Operations

Plant in Service	$492,295,394
Accumulated depreciation	(155,246,692)
Contributions in aid of construction	(196,384,493)
Accumulated amortization of CIAC	70,758,708
Acquisition adjustments	2,055,735
Accum. amort. of acquisition adjustments	1,040,444
Advances for construction	(4,467,841)
Net Plant in Service	210,051,255
Customer deposits	(379,445)
Unclaimed refunds & cost-free capital	(193,255)
Accumulated deferred income taxes	(24,849,085)
Materials and supplies inventory	2,405,967
Excess capacity adjustment	(1,322,276)
Working capital allowance	4,759,698
Original cost rate base	$190,472,859

Rates of return:	
Present	5.99%
Approved	7.17%

SCHEDULE III
Aqua North Carolina, Inc.
Docket No. W-218, Sub 497
Statement of Capitalization and Related Costs
For the Twelve Months Ended September 30, 2017
Combined Operations

	Ratio %	Original Cost Rate Base	Embedded Cost %	Net Operating Income
		PRESENT RATES		
Long-Term Debt	50.00	$95,236,430	4.63	$4,409,447
Common Equity	50.00	95,236,429	7.36	7,007,829
Total	100.00	$190,472,859		$11,417,276
		APPROVED RATES		
Long-Term Debt	50.00	$95,236,430	4.63	$4,409,447
Common Equity	50.00	95,236,429	9.70	9,238,491
Total	100.00	$190,472,859		$13,647,938

SCHEDULE I-A
Aqua North Carolina, Inc.
Docket No. W-218, Sub 497
Net Operating Income for a Return
For the Twelve Months Ended September 30, 2017
Aqua NC Water Operations

	Present Rates	Increase Approved	After Approved Increase
Operating Revenues:			
Service revenues	$34,566,184	$779,663	$35,345,847
Late payment fees	69,132	1,560	70,692
Miscellaneous revenues	766,595	0	766,595
Uncollectibles & abatements	(214,739)	(4,844)	(219,583)
Total operating revenues	35,187,172	776,379	35,963,551
Operating Revenue Deductions:			
Salaries & wages	6,880,614	0	6,880,614
Employee pensions & benefits	2,046,686	0	2,046,686
Purchased water	1,600,928	0	1,600,928
Purchased power	2,164,209	0	2,164,209
Fuel for power production	935	0	935
Chemicals	467,003	0	467,003
Materials & supplies	341,233	0	341,233
Testing fees	628,493	0	628,493

Transportation	618,442	0	618,442
Contractual services-accounting	117,906	0	117,906
Contractual services-legal	122,841	0	122,841
Contractual services-other	1,917,590	0	1,917,590
Rent	208,095	0	208,095
Insurance	435,950	0	435,950
Regulatory commission expense	126,828	0	126,828
Miscellaneous expense	931,131	0	931,131
Interest on customer deposits	25,111	0	25,111
Annualization & consumption adjustments	29,398	0	29,398
Total O&M and G&A expense	18,663,393	0	18,663,393
Depreciation & amortization expense	6,303,842	0	6,303,842
Property taxes	492,594	0	492,594
Payroll taxes	496,537	0	496,537
Other taxes	193,611	0	193,611
Section 338(h) adjustment	(10,817)	0	(10,817)
Regulatory fee	49,262	1,087	50,349
Deferred income tax	(77,166)	0	(77,166)
State income tax	190,625	23,259	213,884
Federal income tax	1,294,345	157,927	1,452,272
Total operating revenue deductions	27,596,226	182,273	27,778,499
Net operating income for return	$7,590,946	$594,106	$8,185,052

SCHEDULE II-A
Aqua North Carolina, Inc.
Docket No. W-218, Sub 497
Original Cost Rate Base
For the Twelve Months Ended September 30, 2017
Aqua NC Water Operations

Plant in Service	$274,648,584
Accumulated depreciation	(93,391,113)
Contributions in aid of construction	(93,199,142)
Accumulated amortization of CIAC	33,674,909
Acquisition adjustments	6,089,670
Accum. amort. of acquisition adjustments	(1,871,736)
Advances for construction	(1,246,720)
Net Plant in Service	124,704,452
Customer deposits	(295,674)
Unclaimed refunds & cost-free capital	(46,582)
Accumulated deferred income taxes	(15,129,055)
Materials and supplies inventory	2,038,514
Excess capacity adjustment	0
Working capital allowance	2,964,922
Original cost rate base	$114,236,577
Rates of return:	
Present	6.65%
Approved	7.17%

SCHEDULE III-A
Aqua North Carolina, Inc.
Docket No. W-218, Sub 497
Statement of Capitalization and Related Costs
For the Twelve Months Ended September 30, 2017
Aqua NC Water Operations

	Ratio %	Original Cost Rate Base	Embedded Cost %	Net Operating Income
		PRESENT RATES		
Long-Term Debt	50.00	$57,118,288	4.63	$2,644,577
Common Equity	50.00	57,118,289	8.66	4,946,369
Total	100.00	$114,236,577		$7,590,946
		APPROVED RATES		
Long-Term Debt	50.00	$57,118,288	4.63	$2,644,577
Common Equity	50.00	57,118,289	9.70	5,540,475
Total	100.00	$114,236,577		$8,185,052

SCHEDULE I-B
Aqua North Carolina, Inc.
Docket No. W-218, Sub 497
Net Operating Income for a Return
For the Twelve Months Ended September 30, 2017
Aqua NC Sewer Operations

	Present Rates	Increase Approved	After Approved Increase
Operating Revenues:			
Service revenues	$13,459,559	$870,679	$14,330,238
Late payment fees	21,535	1,393	22,928
Miscellaneous revenues	123,377	0	123,377
Uncollectibles & abatements	(55,272)	(3,576)	(58,848)
Total operating revenues	13,549,199	868,496	14,417,695
Operating Revenue Deductions:			
Salaries & wages	2,329,549	0	2,329,549
Employee pensions & benefits	696,294	0	696,294
Purchased sewer treatment	440,871	0	440,871
Sludge removal	470,173	0	470,173
Purchased power	1,043,919	0	1,043,919
Fuel for power production	23,053	0	23,053
Chemicals	589,467	0	589,467
Materials & supplies	116,995	0	116,995
Testing fees	251,311	0	251,311
Transportation	212,266	0	212,266

Contractual services-accounting	29,299	0	29,299
Contractual services-legal	30,364	0	30,364
Contractual services-other	1,452,170	0	1,452,170
Rent	52,743	0	52,743
Insurance	149,653	0	149,653
Advertising	555	0	555
Regulatory commission expense	31,702	0	31,702
Miscellaneous expense	316,345	0	316,345
Interest on customer deposits	1,007	0	1,007
Annualization & consumption adjustments	98,887	0	98,887
Total O&M and G&A expense	8,336,623	0	8,336,623
Depreciation & amortization expense	2,191,677	0	2,191,677
Property taxes	23,018	0	23,018
Payroll taxes	124,107	0	124,107
Other taxes	48,126	0	48,126
Section 338(h) adjustment	(5,914)	0	(5,914)
Regulatory fee	18,969	1,216	20,185
Deferred income tax	(30,751)	0	(30,751)
State income tax	54,490	26,018	80,508
Federal income tax	369,987	176,665	546,652
Total operating revenue deductions	11,130,332	203,899	11,334,231
Net operating income for return	$2,418,867	$664,597	$3,083,464

SCHEDULE II-B
Aqua North Carolina, Inc.
Docket No. W-218, Sub 497
Original Cost Rate Base
For the Twelve Months Ended September 30, 2017
Aqua NC Sewer Operations

Plant in Service	$150,401,694
Accumulated depreciation	(43,120,425)
Contributions in aid of construction	(80,683,472)
Accumulated amortization of CIAC	28,072,101
Acquisition adjustments	(4,002,509)
Accum. amort. of acquisition adjustments	2,882,669
Advances for construction	(3,388,691)
Net Plant in Service	50,161,367
Customer deposits	(11,194)
Unclaimed refunds & cost-free capital	(6,342)
Accumulated deferred income taxes	(7,148,914)
Materials and supplies inventory	265,709
Excess capacity adjustment	(1,322,276)
Working capital allowance	1,096,717
Original cost rate base	$43,035,067
Rates of return:	
Present	5.62%
Approved	7.17%

SCHEDULE III-B
Aqua North Carolina, Inc.
Docket No. W-218, Sub 497
Statement of Capitalization and Related Costs
For the Twelve Months Ended September 30, 2017
Aqua NC Sewer Operations

	Ratio %	Original Cost Rate Base	Embedded Cost %	Net Operating Income
		PRESENT RATES		
Long-Term Debt	50.00	$21,517,533	4.63	$996,262
Common Equity	50.00	21,517,534	6.61	1,422,604
Total	100.00	$43,035,067		$2,418,867
		APPROVED RATES		
Long-Term Debt	50.00	$21,517,533	4.63	$996,262
Common Equity	50.00	21,517,534	9.70	2,087,202
Total	100.00	$43,035,067		$3,083,464

SCHEDULE I-C
Aqua North Carolina, Inc.
Docket No. W-218, Sub 497
Net Operating Income for a Return
For the Twelve Months Ended September 30, 2017
Fairways Water Operations

	Present Rates	Decrease Approved	After Approved Decrease
Operating Revenues:			
Service revenues	$1,084,684	($7,461)	$1,077,223
Late payment fees	2,386	(16)	2,370
Miscellaneous revenues	92,938	0	92,938
Uncollectibles & abatements	(5,218)	36	(5,182)
Total operating revenues	1,174,790	(7,441)	1,167,349
Operating Revenue Deductions:			
Salaries & wages	198,653	0	198,653
Employee pensions & benefits	59,291	0	59,291
Purchased water	0	0	0
Purchased power	59,453	0	59,453
Fuel for power production	1,474	0	1,474
Chemicals	20,977	0	20,977
Materials & supplies	5,133	0	5,133
Testing fees	10,165	0	10,165
Transportation	15,976	0	15,976
Contractual services-accounting	8,207	0	8,207

Contractual services-legal	8,473	0	8,473
Contractual services-other	145,938	0	145,938
Rent	13,923	0	13,923
Insurance	13,015	0	13,015
Regulatory commission expense	9,014	0	9,014
Miscellaneous expense	45,467	0	45,467
Interest on customer deposits	642	0	642
Annualization & consumption adjustments	11,993	0	11,993
Total O&M and G&A expense	627,794	0	627,794
Depreciation & amortization expense	179,796	0	179,796
Property taxes	28,236	0	28,236
Payroll taxes	35,301	0	35,301
Other taxes	13,482	0	13,482
Section 338(h) adjustment	0	0	0
Regulatory fee	1,645	(11)	1,634
Deferred income tax	(1,384)	0	(1,384)
State income tax	6,383	(223)	6,160
Federal income tax	43,341	(1,513)	41,828
Total operating revenue deductions	934,594	(1,747)	932,847
Net operating income for return	$240,196	($5,694)	$234,502

SCHEDULE II-C
Aqua North Carolina, Inc.
Docket No. W-218, Sub 497
Original Cost Rate Base
For the Twelve Months Ended September 30, 2017
Fairways Water Operations

Plant in Service	$12,051,221
Accumulated depreciation	(3,301,424)
Contributions in aid of construction	(7,430,398)
Accumulated amortization of CIAC	2,071,911
Acquisition adjustments	0
Accum. amort. of acquisition adjustments	0
Advances for construction	60,570
Net Plant in Service	3,451,880
Customer deposits	(7,436)
Unclaimed refunds & cost-free capital	(7,339)
Accumulated deferred income taxes	(289,485)
Materials and supplies inventory	0
Excess capacity adjustment	0
Working capital allowance	125,273
Original cost rate base	$3,272,893

Rates of return:	
Present	7.34%
Approved	7.17%

SCHEDULE III-C
Aqua North Carolina, Inc.
Docket No. W-218, Sub 497
Statement of Capitalization and Related Costs
For the Twelve Months Ended September 30, 2017
Fairways Water Operations

	Ratio %	Original Cost Rate Base	Embedded Cost %	Net Operating Income
		PRESENT RATES		
Long-Term Debt	50.00	$1,636,447	4.63	$75,767
Common Equity	50.00	1,636,446	10.05	164,429
Total	100.00	$3,272,893		$240,196
		APPROVED RATES		
Long-Term Debt	50.00	$1,636,447	4.63	$75,767
Common Equity	50.00	1,636,446	9.70	158,735
Total	100.00	$3,272,893		$234,502

SCHEDULE I-D
Aqua North Carolina, Inc.
Docket No. W-218, Sub 497
Net Operating Income for a Return
For the Twelve Months Ended September 30, 2017
Fairways Sewer Operations

	Present Rates	Increase Approved	After Approved Increase
Operating Revenues:			
Service revenues	$1,360,925	$723,854	$2,084,779
Late payment fees	2,177	1,159	3,336
Miscellaneous revenues	340	0	340
Uncollectibles & abatements	(7,633)	(4,060)	(11,693)
Total operating revenues	1,355,809	720,953	2,076,762
Operating Revenue Deductions:			
Salaries & wages	180,004	0	180,004
Employee pensions & benefits	52,529	0	52,529
Purchased sewer treatment	1,572	0	1,572
Sludge removal	89,209	0	89,209
Purchased power	88,090	0	88,090
Fuel for power production	659	0	659
Chemicals	111,193	0	111,193
Materials & supplies	8,775	0	8,775
Testing fees	14,028	0	14,028
Transportation	14,480	0	14,480

Contractual services-accounting	5,270	0	5,270
Contractual services-legal	5,468	0	5,468
Contractual services-other	113,553	0	113,553
Rent	8,750	0	8,750
Insurance	13,015	0	13,015
Regulatory commission expense	5,727	0	5,727
Miscellaneous expense	36,617	0	36,617
Interest on customer deposits	14	0	14
Annualization & consumption adjustments	21,165	0	21,165
Total O&M and G&A expense	770,118	0	770,118
Depreciation & amortization expense	370,493	0	370,493
Property taxes	2,527	0	2,527
Payroll taxes	22,391	0	22,391
Other taxes	8,659	0	8,659
Section 338(h) adjustment	0	0	0
Regulatory fee	1,898	1,009	2,907
Deferred income tax	(2,956)	0	(2,956)
State income tax	0	19,731	19,731
Federal income tax	0	133,972	133,972
Total operating revenue deductions	1,173,130	154,712	1,327,842
Net operating income for return	$182,679	$566,241	$748,920

SCHEDULE II-D

Aqua North Carolina, Inc.

Docket No. W-218, Sub 497

Original Cost Rate Base

For the Twelve Months Ended September 30, 2017

Fairways Sewer Operations

Plant in Service	$18,595,484
Accumulated depreciation	(2,333,905)
Contributions in aid of construction	(7,081,614)
Accumulated amortization of CIAC	1,639,386
Acquisition adjustments	0
Accum. amort. of acquisition adjustments	0
Advances for construction	107,000
Net Plant in Service	10,926,351
Customer deposits	(172)
Unclaimed refunds & cost-free capital	(217)
Accumulated deferred income taxes	(587,890)
Materials and supplies inventory	0
Excess capacity adjustment	0
Working capital allowance	114,394
Original cost rate base	$10,452,466
Rates of return:	
Present	1.75%
Approved	7.17%

SCHEDULE III-D
Aqua North Carolina, Inc.
Docket No. W-218, Sub 497
Statement of Capitalization and Related Costs
For the Twelve Months Ended September 30, 2017
Fairways Sewer Operations

	Ratio %	Original Cost Rate Base	Embedded Cost %	Net Operating Income
		PRESENT RATES		
Long-Term Debt	50.00	$5,226,233	4.63	$241,975
Common Equity	50.00	5,226,233	(1.13)	(59,296)
Total	100.00	$10,452,466		$182,679
		APPROVED RATES		
Long-Term Debt	50.00	$5,226,233	4.63	$241,975
Common Equity	50.00	5,226,233	9.70	506,945
Total	100.00	$10,452,466		$748,920

SCHEDULE I-E
Aqua North Carolina, Inc.
Docket No. W-218, Sub 497
Net Operating Income for a Return
For the Twelve Months Ended September 30, 2017
Brookwood Water Operations

	Present Rates	Increase Approved	After Approved Increase
Operating Revenues:			
Service revenues	$5,025,605	$549,865	$5,575,470
Late payment fees	19,600	2,144	21,744
Miscellaneous revenues	372,249	0	372,249
Uncollectibles & abatements	(131,386)	(14,376)	(145,762)
Total operating revenues	5,286,068	537,633	5,823,701
Operating Revenue Deductions:			
Salaries & wages	653,900	0	653,900
Employee pensions & benefits	223,022	0	223,022
Purchased water	273,245	0	273,245
Purchased power	214,996	0	214,996
Fuel for power production	688	0	688
Chemicals	333,327	0	333,327
Materials & supplies	33,584	0	33,584
Testing fees	42,376	0	42,376
Transportation	57,985	0	57,985
Contractual services-engineering	2,750	0	2,750

Contractual services-accounting	27,419	0	27,419
Contractual services-legal	28,998	0	28,998
Contractual services-other	701,566	0	701,566
Rent	26,431	0	26,431
Insurance	39,041	0	39,041
Regulatory commission expense	28,395	0	28,395
Miscellaneous expense	148,145	0	148,145
Interest on customer deposits	5,614	0	5,614
Annualization & consumption adjustments	28,949	0	28,949
Total O&M and G&A expense	2,870,431	0	2,870,431
Depreciation & amortization expense	1,030,601	0	1,030,601
Property taxes	89,088	0	89,088
Payroll taxes	111,148	0	111,148
Other taxes	45,008	0	45,008
Section 338(h) adjustment	(3,293)	0	(3,293)
Regulatory fee	7,400	753	8,153
Deferred income tax	(8,391)	0	(8,391)
State income tax	20,545	16,106	36,651
Federal income tax	139,498	109,362	248,860
Total operating revenue deductions	4,302,035	126,221	4,428,256
Net operating income for return	$984,033	$411,412	$1,395,445

SCHEDULE II-E
Aqua North Carolina, Inc.
Docket No. W-218, Sub 497
Original Cost Rate Base
For the Twelve Months Ended September 30, 2017
Brookwood Water Operations

Plant in Service	$36,598,411
Accumulated depreciation	(13,099,825)
Contributions in aid of construction	(7,989,867)
Accumulated amortization of CIAC	5,300,401
Acquisition adjustments	(31,426)
Accum. amort. of acquisition adjustments	29,511
Advances for construction	0
Net Plant in Service	20,807,205
Customer deposits	(64,969)
Unclaimed refunds & cost-free capital	(132,775)
Accumulated deferred income taxes	(1,693,741)
Materials and supplies inventory	101,744
Excess capacity adjustment	0
Working capital allowance	458,392
Original cost rate base	$19,475,856
Rates of return:	
Present	5.06%
Approved	7.17%

SCHEDULE III-E
Aqua North Carolina, Inc.
Docket No. W-218, Sub 497
Statement of Capitalization and Related Costs
For the Twelve Months Ended September 30, 2017
Brookwood Water Operations

	Ratio %	Original Cost Rate Base	Embedded Cost %	Net Operating Income
		PRESENT RATES		
Long-Term Debt	50.00	$9,737,928	4.63	$450,866
Common Equity	50.00	9,737,928	5.48	533,167
Total	100.00	$19,475,856		$984,033
		APPROVED RATES		
Long-Term Debt	50.00	$9,737,928	4.63	$450,866
Common Equity	50.00	9,737,928	9.70	944,579
Total	100.00	$19,475,856		$1,395,445

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 116-117

The evidence supporting these findings of fact and conclusions are contained in the Application and NCUC Form W-1 of Aqua NC, and in the testimony of Public Staff witness Junis.

In its Application, the Company proposed a company-wide rate increase of 9.19% over the total revenue level generated by the rates currently in effect. When compared to the present schedule of Commission-approved rates, the Company's proposed schedule of rates[1] indicates the Company was seeking to increase the ratio of base charges to commodity charges of the average monthly residential metered bill for the Aqua NC Water, Aqua NC Sewer, and Fairways Sewer rate divisions.

In its proposed order, the Public Staff stated that witness Junis provided multiple iterations of his billing analysis and rate design[2] as part of his direct and supplemental testimonies and late-filed exhibits requested by the Commission in this proceeding. The Public Staff asserted that in each iteration, witness Junis clearly designed rates to remain at or adjust closer to a 40% to 60% split between the base facilities charges and the metered commodity charges, respectively, balancing the promotion of conservation and sustainability of revenues, for the average monthly metered residential bill for each of the Company's rate divisions. The Public Staff pointed out that no party submitted evidence rebutting witness Junis' rate design.

In its proposed order, Aqua NC stated that the Company and the Public Staff did not negotiate rate design issues during their settlement discussions and there are no provisions

[1] The Company's proposed schedule of rates was entered into the record as Exhibit O to the NCUC form "Application for Rate Increase."

[2] Witness Junis' billing analyses and rate designs were entered into the record as Junis Exhibit 25, Junis Supplemental Exhibit 7, and Junis Late-Filed Exhibit 11.

governing rate design structure in the Stipulation filed by those parties. Aqua NC further stated that, to the best of its knowledge, there was no specific narrative testimony filed by either the Company or the Public Staff or cross-examination which directly addressed rate design structure issues. Aqua NC cited Exhibit JW to the Company's Application in support of its proposed rate design and requested that the Commission design new rates in this proceeding utilizing the following ratios of base facilities charges to variable consumption charges: Aqua Water – 44%/56%; Fairways Water – 50%/50%; and Brookwood Water – 44%/56%.

The Company further requested that the Commission adopt and approve the Company's proposed rate design, rather than the Public Staff's rate design reflected in the billing analysis contained in Junis Late-Filed Exhibit 11 and Table 2 (Average Monthly Residential Bill Calculations) of the late-filed exhibit, both filed on October 10, 2018. Aqua NC also asserted that its proposed metered water rate design ratios will help to minimize the Company's demonstrated risk which results from consistently declining consumption by customers.

The Commission concludes that due to the lack of evidence presented in this rate case proceeding pertaining to Aqua NC's request to increase the ratio of base charges to commodity charges of the average monthly residential metered bill for the Aqua NC Water, Aqua NC Sewer, and Fairways Sewer rate divisions, the Commission cannot properly evaluate such request at this time. The Commission gives substantial weight to the fact that witness Junis provided multiple iterations of his billing analysis and rate design as part of his direct and supplemental testimonies and late-filed exhibits requested by the Commission in this proceeding and Aqua NC did not file any rebuttal testimony concerning this issue. Consequently, the Commission finds and concludes that it is appropriate for the rate design of the approved rates to remain at or adjust closer to a 40% to 60% split between the base facilities charges and the metered commodity charges, respectively, as presented by the Public Staff in this proceeding. The rate design and rates, necessary and appropriate to provide Aqua NC a reasonable opportunity to recover the approved revenue requirement in this proceeding, are reflected in Appendices A-1, A-2, A-3, and A-4, attached hereto.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 118-119

The evidence supporting these findings of fact and conclusions can be found in the Application and NCUC Form W-1 of Aqua NC, and in the testimony of Aqua NC witness Becker and the testimony of Public Staff witness Junis.

In his testimony, Aqua NC witness Becker asserted that, over the last several years, the average consumption per customer has varied widely due to environmental factors, conservation, and pricing impact. Witness Becker cited the "Studies of Volumetric Wastewater Rate Structures and a Consumption Adjustment Mechanism for Water Rates of Aqua North Carolina, Inc."[1] completed by the EFC at the UNC School of Government, which provides in pertinent part that, "[t]he analysis demonstrates that average water use has declined significantly among Aqua water customers, relative to test year average water use, although it has recently stabilized close to 5,000 gallons/month average for ANC customers." Tr. Vol. 5, pp. 43-44.

[1] The EFC Report was filed in Docket No. W-218, Sub 363A on March 31, 2016.

Witness Becker asserted that, though the trend is one of declining consumption, it should be noted that consumption can also increase significantly during periods of warm weather. He also asserted that declining consumption can be attributed to several factors including more efficient plumbing fixtures and household appliances, governmental programs encouraging greater efficiency in water use, changes in landscaping patterns, and consumer responses to these price signals. Id. at 44.

Witness Becker further testified that persistent decline in consumption has eroded Aqua NC's opportunity to earn its authorized return and that in order to minimize the impact of significant swings in customer consumption patterns, the Company proposes the Consumption Adjustment Mechanism (CAM) for approval by the Commission. Id. at 45.

Witness Becker explained how the proposed CAM would operate. He detailed that an average monthly consumption per metered bill would be established based on the total metered consumption and the total metered bills of all metered residential and commercial premises included in the applicable rate division tariff. Annually, the actual average monthly consumption per metered bill would be compared to the average monthly consumption calculated for use to determine rates within the previous rate case. If the current average monthly consumption is within a range of +/- 1%, then no credit/surcharge adjustment would be required. However, if it is outside the range, then the total annual revenue excess/shortfall[1] would be computed and divided by the number of bills and then divided by 12 months to establish the monthly CAM to be applied to the monthly bills for the metered accounts. Id. at 45-46.

On cross-examination, witness Becker agreed that legislation at the North Carolina General Assembly similar to the proposed CAM had not been ratified. Id. at 58-59.

Public Staff witness Junis testified that the Public Staff believes any new rate mechanism, such as the CAM, should be authorized by the North Carolina General Assembly before being considered by the Commission for rulemaking. Tr. Vol. 12, p. 160. Witness Junis further testified that, during the 2017-2018 Session, House Bill 752 would have added language to N.C.G.S. § 62-133 authorizing customer usage tracking and rate adjustments but it was not enacted. Witness Junis concluded that the General Assembly did not authorize this mechanism though it made other changes to Chapter 62 of the Public Utilities Act specifically involving water and wastewater utilities. Thus, according to the Public Staff, the Commission should not authorize a CAM. Tr. Vol. 12, pp. 160-61.

Witness Junis further explained that, if the average monthly usage was 5,000 gallons, then the proposed 1% threshold for consumption variance would amount to 50 gallons per day of shower flow. He asserted that the trigger for the mechanism was too narrow. Id. at 161.

Witness Junis testified that the proposed mechanism as described in witness Becker's testimony utilized average usage per bill and ignored the short-term revenue gains from growth. Witness Junis cited the EFC Report which confirmed in the short-term that the revenues from

[1] The difference between the current monthly average and the rate case average monthly consumption multiplied by 12 months and then multiplied by the consumption tariff rate.

growth exceed the associated costs. He explained that the proposed CAM would allow Aqua NC to increase rates for decreased average usage even if the customer growth resulted in the Company otherwise collecting its full revenue requirement. Id. at 162.

In his rebuttal testimony, Company witness Becker again cited the EFC Report, which provides in pertinent part that, "[t]hat analysis demonstrates that average water use ... has recently stabilized close to 5,000 gallons/month average for ANC customers." Tr. Vol.14, p. 49.

Upon questioning from Presiding Commissioner Brown-Bland, witness Becker contested the 2016 conclusion by the EFC that consumption had stabilized, based on his experience in Virginia and noting the price elasticity of demand. Becker asserted that the phenomenon of reduced consumption is almost universally experienced among both public and private water providers, and that one of the drivers of the instant case is reduced consumption per customer. Conversely, though the trend is one of declining consumption, witness Becker observed that consumption can also increase significantly during extended periods of warm weather; therefore, fluctuation is a factor that should also be addressed.

Further, witness Becker disagreed with the Public Staff's objections to the CAM and asserted that none of them present an impediment to Commission approval of a CAM. He even asserted that proof of the declining average consumption had been presented and was not refuted by the Public Staff, despite the purportedly contradictory finding of the EFC that average water use has stabilized and the inconsistency of the consumption factors that range from negative 1.83% to positive 2.97% across the five Aqua NC rate divisions.

In its post-hearing brief, the AGO expressed opposition to Aqua NC's request for the implementation of the CAM. The AGO maintained that the proposed mechanism is not authorized by the ratemaking provisions in Chapter 62 and Aqua NC has not justified the approval of a non-statutory rider. Further, the AGO contended that the new rider would harm consumers by increasing the frequency of changes to rates outside of a general rate proceeding, by shifting business risks from investors to users, and by discouraging water conservation efforts.

The AGO explained that legislation was introduced in the General Assembly in 2017 that, if adopted, would have authorized the creation of a rate adjustment mechanism for water and wastewater utilities based on changes in consumption – if such a mechanism were determined by the Commission to be in the public interest. However, the legislation was not enacted. See Ex. Vol. 5, pp. 12-13.

The AGO concluded that, in light of the General Assembly's decision not to authorize this rate adjustment mechanism, the Commission should reject Aqua NC's request that it approve such a mechanism as an exercise of discretion. Tr. Vol. 12, p. 161.

Further, the AGO pointed out that that North Carolina appellate courts have approved the Commission's use of non-statutory riders in very limited circumstances such as (1) highly variable and unpredictable expense or volume levels, (2) of significant magnitude, (3) that are beyond the control of the utility. State ex rel. Util. Comm. v. Edmisten, 291 N.C. 327, 230 S.E.2d 651 (1976); State ex rel. Util. Comm. v. Public Service Co., 35 N.C. App. 156, 241 S.E.2d 79 (1978); See

Order Approving Partial Rate Increase, p. 11, Docket No. G-5, Sub 356 (N.C.U.C. Sept. 25, 1996) (holding that absent extraordinary circumstances, current law does not allow riders).

The AGO contended that 2016 EFC report, upon which Aqua NC relies to establish a decline in consumption, found there was initially a significant decline relative to test year consumption but that usage stabilized more recently. Tr. Vol. 5, p. 44. The AGO argued that the variations in usage are considered "a hindrance" by Aqua NC to its ability to earn its allowed return on equity, but that such variations are not of a sufficient magnitude to justify an extraordinary rate mechanism. Tr. Vol. 5, p. 62.

Moreover, the AGO maintained that the mechanism is designed to make rate adjustments for changes in per customer consumption without consideration of other factors that tend to offset the impact, such as growth in the number of customers that Aqua NC serves. Tr. Vol. 5, pp. 45-46, 57. Aqua NC is a growing company, and as it increases its customer count, its revenues collected in usage rates taking into account growth, may fully offset any reduction in per-customer consumption. Tr. Vol. 12, p. 162.

The AGO noted that Aqua NC's CAM proposal would trigger a rate adjustment based on a collar; i.e., if the actual average monthly consumption per bill is higher than plus 1% or lower than minus 1% of the average monthly consumption established in the last rate case. The AGO further noted that Aqua NC contends that having the collar means that the mechanism would address only "significant" changes in per-customer consumption. However, the AGO pointed out that Public Staff witness Junis questioned the significance of a 1% variation in average consumption, as a 1% change could occur from a relatively small departure from normal habits, such as by shortening a daily shower by less than a minute. Tr. Vol. 12, p. 161.

Furthermore, the AGO argued that the proposed rider harms consumers by increasing the frequency of changes to rates outside of general rate proceedings. In a general rate case, Aqua NC would be required to "net" all costs and benefits of operation at the time rates are set, taking into consideration offsetting cost decreases as well as other offsetting factors. Instead, by authorizing changes in rates targeted to variations in per-customer consumption, the AGO opined that the Commission would be allowing Aqua NC to shift normal business risk associated with a single factor from its investors to ratepayers. Aqua NC's incentives to actively manage costs and to operate efficiently in order to maximize the Company's return would be reduced if risks are shifted in that manner. Finally, the AGO maintained that consumers will tend to be discouraged from investing in water conservation measures if their efforts are met with an offsetting rate increase.

In sum, the AGO concluded that the new rate adjustment mechanism proposed by Aqua NC in this proceeding should be rejected because it is not authorized by statute, is not justified, and would be harmful to consumers.

The Commission has carefully evaluated the evidence presented in this proceeding concerning Aqua NC's request to implement a CAM. The Commission finds persuasive the evidence presented by the Public Staff and agrees with the arguments of the AGO that the proposed CAM is not appropriately structured. More specifically, the Commission agrees with Public Staff witness Junis that the 1% threshold is too narrow, and would inappropriately trigger a rate change based on relatively small departures from normal consumption habits, such as shortening a daily shower by less than one minute. The Commission, therefore, finds that Aqua NC has not demonstrated that a consumption adjustment mechanism is reasonable or justified in this case.

In making this finding, the Commission gives substantial weight to the arguments of the Public Staff and the AGO that the mechanism was designed to make rate adjustments for changes in per customer consumption without consideration of other factors that tend to offset the impact, such as growth in the number of customers that the Company serves and periods of warm weather. The Commission concludes that these factors are relevant in determining whether circumstances establish that a decline in consumption denies the Company a reasonable opportunity to earn its authorized rate of return and whether the CAM is reasonable or justified based on the evidence in this case.

The Commission also gives significant weight to the EFC Report which demonstrates that the average water use by Aqua NC customers has recently stabilized close to 5,000 gallons per month average for Aqua NC customers. The Commission accepts the undisputed evidence that average consumption for Aqua NC Water Operations for the purposes of this proceeding, is approximately 5,000 gallons per month on average, as calculated by witness Junis, and agreed to by the Company. The Commission finds unpersuasive the testimony of Company witness Becker that he expects consumption to decrease further given consumption patterns he observed while working at another Aqua America company in Virginia.

Based upon the foregoing and the entire record herein, the Commission finds that Aqua NC has failed to demonstrate that its proposed CAM is reasonable or justified for the purposes of this case. The Commission, therefore, concludes that Aqua NC's request for approval to implement its proposed CAM should be denied.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 120-121

The evidence supporting these findings of fact is contained in the testimony of Public Staff witness Henry.

Witness Henry testified that consistent with Commission Rules R7-39(k) and R10-36(k), Aqua NC WSIC and SSIC surcharges will reset to zero as of the effective date of the approved rates in this proceeding. Additionally, witness Henry stated that by law, the cumulative maximum charges that the Company can recover between rate cases cannot exceed 5% of the total service revenues approved by the Commission in this rate case.

The Commission's previously approved WSIC/SSIC improvement charge rate adjustment mechanisms continue in effect, although these surcharges have been reset to zero in this rate case. Further, the Company's Commission-authorized WSIC mechanism will, on a going-forward basis, apply to Aqua NC's customers receiving water utility service from (1) Timberlake and Thornton Ridge water systems in Alamance County; (2) Wimbledon, Glennburn, and Knollwood water systems in Gaston County; and (3) Clear Meadow water system in Mecklenburg County, which have been incorporated into Aqua NC Water Operations uniform rates in this proceeding. The WSIC/SSIC mechanisms are designed to recover, between rate case proceedings, the costs associated with investment in certain completed, eligible projects for water or sewer improvements. The WSIC/SSIC surcharges are subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC/SSIC mechanisms may not exceed 5% of the total annual service revenues approved by the Commission in this rate case proceeding.

Based on the service revenues set forth and approved in this Order, the maximum WSIC/SSIC charges as of the effective date of this Order are:

	Service Revenues		WSIC & SSIC Cap
Aqua NC Water	$35,345,847	x 5% =	$1,767,292
Aqua NC Sewer	$14,330,238	x 5% =	$ 716,512
Fairways Water	$ 1,077,223	x 5% =	$ 53,861
Fairways Sewer	$ 2,084,779	x 5% =	$ 104,239
Brookwood Water	$ 5,575,470	x 5% =	$ 278,774

IT IS, THEREFORE, ORDERED as follows:

1. That the Stipulation between Aqua NC and the Public Staff, is hereby approved.

2. That the Schedule of Rates, attached hereto as Appendices A-1, A-2, A-3, and A-4, are hereby approved and deemed filed with the Commission pursuant to N.C.G.S. § 62-138.

3. That the attached Schedule of Rates is hereby authorized to become effective for service rendered on and after the issuance date of this Order.

4. That a copy of the Notice to Customers, attached hereto as Appendices B-1, B-2, and B-3, shall be mailed with sufficient postage or hand delivered to all affected customers in each relevant rate division, respectively, by Aqua NC in conjunction with the next regularly scheduled billing process.

5. That the Company shall file the attached Certificate of Service, properly signed and notarized, not later than 45 days after the issuance of this Order.

6. That neither the Stipulation entered and filed on September 17, 2018, nor the parts of this Order pertaining to the contents of that agreement shall be cited or treated as precedent in future proceedings.

7. That the 2017 water and wastewater depreciation studies and rates filed by Aqua NC in this docket are reasonable and appropriate for use in setting water and sewer rates in this proceeding and are proper for the Company to use in booking depreciation expenses going forward. The 2017 water and wastewater depreciation rate studies are hereby approved as filed.

8. That the Chief Clerk shall establish Docket No. W-218, Sub 497A as the reporting requirement docket for Commission-required reports as ordered herein and also for WSIC/SSIC filings.

9. That Aqua NC shall continue to file bi-monthly reports addressing water quality concerns raised by customers at the public hearings in W-218 Sub 363, in situations where the iron/manganese concerns remain, and in this proceeding, including but not limited to customers served within the Bayleaf Master System. Such reports shall describe measures taken by Aqua NC to address water quality issues and shall include summaries of customer concerns raised, results of water laboratory analyses (including soluble and insoluble concentration levels of iron and manganese) to measure baseline concentration levels and the effectiveness of chemical sequestration treatment, flushing regimens, and cost estimates to install filtration systems (greensand or other filtration options deemed appropriate) or to procure alternate water sources. The first of the bi-monthly reports, which shall cover the time period of November-December 2018, shall be due on January 31, 2019, and shall continue to be filed until further Order of the Commission.

10. That the Public Staff and Aqua NC shall continue to work together to develop and implement plans to identify and respond to water quality concerns that occur in significant numbers in individual subdivision service areas. At a minimum, the Public Staff and Aqua NC are required to file a written report with the Commission, on February 1 and August 1 each year in which the WSIC is in effect, on secondary quality concerns that are affecting its customers. If a particular secondary water quality concern has affected or is affecting 10% of the customers in an individual subdivision service area or 25 billing customers in an individual service area, whichever is less, the customers affected and the estimated expenditures that are necessary to eradicate to the extent practicable water quality issues related to iron and manganese through the use of projects that are eligible for recovery through the WSIC shall be detailed in the written report. The written report shall also contain a recommendation as to whether the Commission should order Aqua NC to pursue such corrective action and/or an underlying reason why the action should or should not be undertaken. If there are no secondary water issues or if the secondary water quality issues are below the 10%/25 threshold previously set forth, Aqua NC and the Public Staff shall so inform the Commission, but they need not report secondary water quality issues resolved by Aqua NC without the assistance or expectation of assistance of the WSIC; Aqua NC shall develop a process that allows it to capture all water quality-related complaints for compliance with this Ordering Paragraph, regardless of the time of day they are received; and Aqua NC and the Public Staff shall supplement the Seventh and Eighth Semi-Annual Reports Concerning Secondary Water Quality Concerns with any after-hours call data that was not included when the reports were first filed with the Commission.

11. That Aqua NC shall also continue to file its annual Three-Year WSIC and SSIC Plan, as well as its Quarterly Earnings, WSIC/SSIC Revenues, and Construction Status reports, its Annual Heater Acquisition Incentive Account Report, the DEQ Quarterly Notice of Deficiency filings, and the DEQ Secondary Water Quality Filtration Request Executive Summary.

12. That the Public Staff shall file quarterly reports beginning April 30, 2019 for the first quarter of 2019 detailing the number of water quality complaints against Aqua NC received

by Public Staff (including by its Consumer Services Division), the nature of those complaints, and the final resolution.

13. That at any time after a year from the issuance of this Order, Aqua NC may request that the Commission revise or eliminate the regular and periodic reporting requirements ordered herein due to demonstrated and significant progress in customer satisfaction with improvements made in water quality related to levels of iron and manganese.

14. That Aqua NC shall promptly provide to and share with the Public Staff information concerning all meetings and conversations (in summary note form) with, reports to, and the recommendations of DEQ regarding the water quality concerns being evaluated and addressed in Aqua NC's systems. Such communication to the Public Staff shall not be considered or treated as a formal report authored by Aqua NC, but rather as notification of the occurrence of communications between the Company and DEQ and notification of salient topic and content points, shall be in a written format and shall be provided, at a minimum, on a bi-monthly basis until otherwise ordered by the Commission. Without limitation on the foregoing, Aqua NC shall provide the Public Staff copies of: (a) Aqua NC's reports and letters to DEQ concerning water quality concerns in its systems; (b) responses from DEQ concerning reports, letters, or other oral or written communication received from Aqua NC; (c) DEQ's specific recommendations to Aqua NC, by system, concerning each of the water quality concerns being evaluated by DEQ; and (d) communications from DEQ to Aqua NC indicating DEQ's dissatisfaction with Aqua NC's response to DEQ's concerns, directions or recommendations concerning water quality affected by iron and manganese.

15. That Aqua NC shall file copies of its North Carolina Water Quality Plan and Customer Communication Plan, including, without limitation in its Water Quality plan, Aqua NC's methods to identify and address the presence of iron and manganese at levels reasonably known by Aqua to damage pipes and appliances and to be objectionable to customers for drinking and to identify and address other potential contaminants in the Company's water systems; and detailing in its Customer Communication plan (a) the Company's plans to provide timely and accurate notice to its customers of any water quality problems requiring health alerts and to communicate the steps the Company plans to address the problems; (b) the Company's plans to provide better targeted and timely notice of flushing events to customers most likely to be impacted; (c) the Company's plan to establish a dedicated contact or a special call routing protocol for customers encountering sudden or worsening water quality issues; and (d) the Company's plan to invite customers, at least as it pertains to Bayleaf customers, to participate in focus groups to improve customer understanding of issues affecting water quality. See Tr. Vol. 5, pp. 151-55. Such information shall be filed with the Commission within 90 days after issuance of this Order.

16. That as part of its Communication Plan, Aqua NC shall recommend the appropriate and most effective type of individual filtration systems for those customers served by systems affected by iron and manganese.

17. That given the number of customers and systems affected by iron and manganese, Aqua NC shall investigate and evaluate the possibility of entering into agreements with vendors of home water filtration systems and replacement filters for such systems for a discount for Aqua NC customers and shall file a report with the Commission on the status of this evaluation within

90 days after issuance of this Order and every 90 days thereafter until such investigation and evaluation is complete.

18. That Aqua NC shall work with the Public Staff to develop an appropriate robust general flushing plan for each of its North Carolina systems affected by iron and manganese (or identified as a Group 1 site in the Three-Year WSIC/SSIC Plan Update dated April 20, 2018 (or the most recent version thereof)) and submit the plans for filing with the Commission within 180 days of the issuance of this Order.

19. That Aqua NC's general flushing plan filed pursuant to Ordering Paragraph 11 shall be subordinate to the manufacturer's recommended flushing schedule whenever a sequestering agent, including SeaQuest® is introduced into a Company water system. Aqua NC shall follow the manufacturer's recommended flushing schedule, and any time Aqua NC does not follow the manufacturer's recommendation, the Company shall make a filing with the Commission if the recommended flushing does not occur within 60 days of the recommended time for flushing; such filing shall be made within 60 days of departing from the original recommended schedule, explaining the reasons the flushing schedule could not be followed.

20. That Aqua NC shall work with the Public Staff to develop a policy and procedure for providing customers a bill credit when Aqua NC recommends that a customer flush his/her individual line to address a water quality issue. Within 90 days from the issuance of this Order, Aqua NC and the Public Staff shall submit to the Commission for approval their proposed policy and procedure for determining to whom, how and when bill credits will be given as well as how much the flushing bill credit will be.

21. That Aqua NC and the Public Staff shall give full consideration to evaluation and pursuit of a permanent alternate source of water for the Bayleaf Master System or for those points of entry in the Bayleaf Master System for which Aqua NC has no reasonable belief that the water from such points of entry will be suitable consistently for domestic use after reasonable corrective action.

22. That all future reports filed with the Commission related to the two annual reporting requirements established in Docket No. 218, Sub 274 by Ordering Paragraph Nos. 7 and 19, as modified in Docket No. W-218, Sub 319 by lOrdering Paragraph Nos. 7 and 8, regarding Aqua NC's analysis of the terms of its debt issues and the Heater Acquisition Incentive Account, respectively, shall be filed in Docket No. W-218, Sub 497A, until further order of the Commission.

23. That Aqua NC shall file and request approval of all future contracts with developers/secondary developers within 30 days after signing said contracts, and, in the case of informal agreements or contracts that are effective without signing, Aqua NC shall file a detailed written description of the terms of those agreements within 30 days after entering into such agreements. The requirements of this ordering paragraph shall apply to all future contracts, including those covering contiguous expansions. If the contracts have provisions which allow for charges in excess of what is being collected as CIAC, the referenced charges or fees shall be specifically brought to the attention of the Commission for its approval or disapproval.

24. That Aqua NC shall prepare amendments to its tariffs detailing its connection/capacity fee practices and procedures on a subdivision-by-subdivision basis. Within 30 days following issuance of this Order, Aqua NC shall propose for Commission approval a proposed schedule in which it will include in its tariffs all connection fees included in its rates, as ordered by this ordering paragraph.

25. That Aqua NC shall, within 30 days following issuance of this Order, make a compliance filing to show its present and future accounting treatment, in a manner consistent with the findings and conclusions of the Commission herein, of the capacity purchased from, and transmission expenses paid to, Johnston County. Such filing shall include the net rate base adjustment and total revenue requirement effect to the Company as a result of the Commission's determinations of these issues herein.

26. That Aqua NC shall take the appropriate measures to share the 40-day read history collected by the Company's AMR technology with the AMR-metered customers and shall notify the Commission when such information is being shared, including how such information is being provided to customers.

27. That within six months following the issuance date of this Order, Aqua NC shall file a report informing the Commission regarding the specific nature of the expected benefits to be achieved on a consolidated basis for the Aqua America subsidiaries, including Aqua NC, once full deployment of AMR technology is completed in all Aqua America operating states. Such report shall also indicate the planned timing of such expected benefits.

28. That the amount of tax expense that was overcollected in rates from January 1, 2018 until the new rates approved herein take effect shall be returned by Aqua NC to ratepayers as a bill credit over a period of one year.

29. That the excess accumulated deferred income taxes associated with the change in the North Carolina corporate income tax rate under HB 998 shall be returned by Aqua NC to ratepayers in a rider to rates over a three-year period.

30. That the unprotected excess accumulated deferred income taxes associated with the reduction in the federal corporate income tax rate shall be returned by Aqua NC to ratepayers in a rider to rates over a three-year period.

31. That the Chief Clerk shall close Docket No. W-218, Sub 363A and Docket No. W-218, Sub 319A.

ISSUED BY ORDER OF THE COMMISSION.
This the 18th day of December, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

Commissioner Daniel G. Clodfelter concurring in part and dissenting in part.

DOCKET NO. W-218, SUB 497

Commissioner Daniel G. Clodfelter, concurring in part and dissenting in part:

I join in all of the Commission's findings and conclusions and in its Order, except for Findings of Fact 64, 65, 66, 81, and 82. To the extent, but only to the extent, the Commission's determination of the Company's revenue requirement and, ultimately, the approved schedule of rates depend on those five findings I dissent. The Commission's Order fully canvasses the evidence pertinent to these five findings. On this record I find the analysis and position taken by the Public Staff with respect to the matters addressed by those five findings to be more persuasive as a general matter of fact and policy, but in this case especially so in light of the ongoing work the Company needs to undertake to address and resolve customer issues relating to iron and manganese levels in the water from a number of its wells.

/s/ Daniel G. Clodfelter
Commissioner Daniel G. Clodfelter

APPENDIX A-1
PAGE 1 OF 8

SCHEDULE OF RATES

for

AQUA NORTH CAROLINA, INC.

for providing water and sewer utility service in

ALL ITS SERVICE AREAS IN NORTH CAROLINA AND THE EMERGENCY OPERATION OF MOBILE HILL ESTATES

WATER UTILITY SERVICE

►*All Aqua NC systems except as noted below*

Monthly Metered Service (residential and commercial customers):

Base facility charge (zero usage, based on meter size)

<1" meter	$ 19.25
1" meter	$ 48.13
1½" meter	$ 96.25
2" meter	$ 154.00
3" meter	$ 288.75
4" meter	$ 481.25
6" meter	$ 962.50

Usage charge, per 1,000 gallons	$ 5.83

For bulk purchased water system usage charges see attached Appendix A-2

Monthly Unmetered Service (flat rate): [1/]

Residential customers	$ 39.66
Commercial customers, per residential equivalent unit (REU)	$ 67.42

▶*Brookwood and LaGrange Service Areas*
Cumberland and Hoke Counties

Monthly Metered Service (residential and commercial customers):

Base facility charge (zero usage, based on meter size)

<1" meter	$ 14.03
1" meter	$ 35.08
1½" meter	$ 70.15
2" meter	$ 112.24
3" meter	$ 210.45
4" meter	$ 350.75
6" meter	$ 701.50

Usage charge, per 1,000 gallons	$ 3.76

For bulk purchased water system usage charges see attached Appendix A-2

WATER AND SEWER – RATE INCREASE

Monthly Unmetered Service (flat rate): 1/

Residential customers	$ 33.17
Commercial customers (per REU)	$ 56.39

►*Fairways and Beau Rivage Service Area – New Hanover County*

Monthly Metered Service (residential and commercial customers):

Base facility charge (zero usage, based on meter size)

<1" meter	$ 8.36
1" meter	$ 20.90
1½" meter	$ 41.80
2" meter	$ 66.88
3" meter	$ 125.40
4" meter	$ 209.00
6" meter	$ 418.00

Usage charge, per 1,000 gallons	$ 1.53

OTHER MATTERS

Specific Service Area Connection Charges and Capacity Fees: 2/
(see attached Appendix A-3)

Connection in All Other Service Areas: 2/

<1" meter	
For taps made to existing mains installed inside franchised service area	$800.00
For individual connections installed outside franchised service area3/	Actual cost of installation 4/
1" meter or larger	120% of actual cost of making tap, including setting meter and box

WATER AND SEWER – RATE INCREASE

Meter Installation Fee:	$70.00

(The fee will be charged only where cost of meter installation is not otherwise recovered through connection charges.)

Production and Storage Contribution in Aid of Construction Fee: [3/]

For individual connections outside franchised service areas where lot owner has made no contribution in aid of construction toward production and storage facilities	$1,700 per residential equivalent unit (REU)

Reconnection Charges: [5/]

If water service cut off by utility for good cause	$35.00
If water service discontinued at customer's request	$15.00

Billing Service Charge: [6/]	$2.00 per month per bill
New Customer Account Fee:	$20.00

APPENDIX A-1
PAGE 4 OF 8

SEWER UTILITY SERVICE

►*All Aqua systems except as noted below*

Monthly Unmetered Service (flat rate):

Residential customers	$ 72.04
Commercial customers (per REU)	$ 100.86

STEP system flat rate (Monticello, Holly Brook, Saddleridge)	$ 32.00

Monthly Metered Service (commercial customers):

Base facility charge (zero usage, based on meter size)

<1" meter	$ 26.11
1" meter	$ 65.28
1½" meter	$ 130.55

2” meter	$ 208.88
3” meter	$ 391.65
4” meter	$ 652.75
6” meter	$1,305.50

Commercial usage charge, per 1,000 gallons	$ 8.92

For bulk purchased sewer system charges see attached Appendix A-2

►*Fairways and Beau Rivage Service Area – New Hanover County*

Monthly Unmetered Service (flat rate):

Residential customers	$ 58.56
Commercial customers (per REU)	$ 81.98

Monthly Metered Service (commercial customers):

Base facility charge (zero usage, based on meter size)

<1” meter	$ 20.72
1” meter	$ 51.80
1½” meter	$ 103.60
2” meter	$ 165.76
3” meter	$ 310.80
4” meter	$ 518.00
6” meter	$1,036.00

Commercial usage charge, per 1,000 gallons	$ 9.46

OTHER MATTERS

Specific Service Area Connection Charges and Capacity Fees: [2/]
(See attached Appendix A-3)

Connection in All Other Service Areas:

None when tap and service line installed by developer.

Actual Cost if Aqua NC makes tap or installs service line.

Sewer Plant Capacity Fee per GPD (DEQ Design Requirements) – River Park Development:

Sewer Plant Capacity Fee per GPD (See Docket No. W-218, Sub 143)	$ 10.00

Sewer Plant Capacity Fee per GPD – Flowers Plantation Development (Buffalo Creek):
(See Docket No. W-218, Sub 497)

Sewer plant capacity fee per GPD	$ 5.34
Transmission fees per GPD	3.14
Total fees per GPD	$ 8.48

These are the actual rates per GPD paid by Aqua NC to Johnston County on June 21, 2018. Such rates per GPD are subject to change based on future negotiations between Aqua NC and Johnston County.

Developer Contribution to Aqua NC – 50% Aqua NC's Cost of Buffalo Creek Pump Station and Force Main – Flowers Plantation Development (Buffalo Creek):

Pursuant to Amended Purchase Agreement dated May 14, 2002, between River Dell Utilities, Inc., Rebecca Flowers Finch (d/b/a River Dell Company), and Heater Utilities, Inc. (See Docket No. W-274, Sub 538 and Docket No. W-218, Sub 497)

$440,816 divided equally among the first 2,000 single-family residential equivalents (SFREs) or $220.41 per SFRE

Reconnection Charges: [5/]

If sewer service cut off by utility for good cause	Actual Cost

Grease Traps:

The Utility may require installation and/or proper operation of grease traps on grease producing commercial facilities. Failure to properly operate grease traps will result in disconnection of service pursuant to Commission Rule R10-16.

New Customer Account Fee: $ 20.00

(If customer receives both water and sewer utility service from Aqua NC, then the customer shall only be charged a new account fee for water.)

Grinder Pump Installation Fee – Governors Club Subdivision: Actual Cost
(See Docket No. W-218, Sub 277)

The homeowner or house builder shall be required to prepay in full to the outside contractor installing the grinder pump the entire cost of the installation, including the applicable engineering inspection fee, as specified in Aqua NC's Grinder Pump Installation In-house Procedures, a copy of which is filed with the Commission.

Once the grinder pump is initially installed, it will be the responsibility of Aqua NC to maintain, repair, and replace the grinder pump. However, if damage to a grinder pump is shown to be due to homeowner negligence, the homeowner will be liable for the cost of the repair or replacement of the grinder pump.

Returned Check Charge:	$25.00
Bills Due:	On billing date
Billing Frequency:	Monthly for service in arrears
Bills Past Due:	15 days after billing date
Finance Charges for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date

Availability Rates:

Woodlake Subdivision:
Water $5.00 per month
Sewer $3.75 per month

Governors Village Subdivision, Governors Forest Subdivision, Governors Village Townhomes:
Sewer only $150.00 per year per residential lot

Governors Club:
Sewer only $20.00 per month

Notes:

1/ The Utility, at its expense, may install a meter and charge the metered rate.

2/ In most areas, connection charges do not apply pursuant to contract and only the $70.00 meter installation fee will be charged to the first person requesting service (generally the builder). Where Aqua NC must make a tap to an existing main, the charge will be $800.00, and where main extension is required, the charge will be 120% of the actual cost.

3/ Individual connections outside franchised service areas may be made pursuant to this tariff in the following circumstances: (1) upon request of a bona fide customer as that term is defined in Commission Rule R7-16(a)(1); (2) the customer shall be located either within 100 ft. of a Franchised Service Area or located within 100 ft. of an existing Aqua NC main; and (3) the request may come from no more than two customers located in the same area (requests for more than two connections require an application for a new franchise or a request for approval of a contiguous extension). To connect such a customer, Aqua NC shall file a notice with the Commission in Docket No. W-218, Sub 177, at least 30 days before it intends to make the tap. This notice shall include an explanation of the circumstances requiring the tap and an 8.5" x 11" map showing the location of the tap in relation to Aqua NC's existing main. If the Public Staff does not object to the tap within the 30-day period, or upon written notice within that period from the Public Staff that it will not object, Aqua NC may proceed with the connection.

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4/ Actual cost for such a connection shall include installation of a 6" or smaller main extension (if necessary), tap of the main, service line, road bore (if necessary), meter box, meter, backflow preventer (if necessary), and Aqua NC's direct labor costs. Aqua NC shall give a written cost quote to the customer(s) applying for connection before actually beginning the installation work.

5/ When service is disconnected and reconnected by the same unit owner within a period of less than nine months, the entire flat rate and/or base charge rate will be due and payable before the service will be reconnected.

If sewer disconnection is required, after all reasonable efforts by the Utility to encourage the customer to comply with the provisions of the tariff have been made, the Utility may install a valve or other device appropriate to cut off or block the customer sewer line.

Prior to disconnection, the Utility shall give the customer written notice at least seven days prior to disconnection. Said notice shall include, at the minimum, a copy of this reconnect provision and the estimated cost to make the cut off and install the valve or other device.

In the event that an emergency or dangerous condition is found or fraudulent use is detected, sewer service may be cut off without notice. In such an event, notice as described above, will be given as soon as possible.

Upon payment of outstanding balance, actual cost of termination and reconnection and other fees (for example, deposit if required by the Utility), the Utility shall restore the service no later than the next business day.

6/ Aqua NC is authorized to include on its monthly water bill the charges resulting from sewer service provided by the Town of Cary, the Town of Fuquay-Varina, Wake County, and various Commission appointed emergency operators where specifically approved by the Commission. Aqua NC will bill the Town of Cary, the Town of Fuquay-Varina, Wake County, or emergency operator $2.00 per month per bill for providing this service.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-218, Sub 497, on this the 18th day of December, 2018.

APPENDIX A-2
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AQUA NORTH CAROLINA, INC.
BULK PURCHASED WATER SYSTEM USAGE RATES

Usage charge, per 1,000 gallons where water purchased for resale

Service Area	Water Provider	Usage Charge/ 1,000 gallons
Aqua North Carolina Service Areas		
Twin Creeks	City of Asheville	$ 4.26
Heather Glen and Highland	City of Belmont	$14.40
Southpoint Landing	City of Belmont	$14.40
Park South	City of Charlotte	$ 1.81
Parkway Crossing	City of Charlotte	$ 1.81
Springhill / Springdale	City of Concord	$ 5.11
Hoopers Valley	City of Hendersonville	$ 3.06
Crystal Creek	City of Hendersonville	$ 3.06
Rambling Ridge	City of Hendersonville	$ 3.06
Brookwood	City of Hickory (outside city)	$ 5.04
Heritage Farms	City of Hickory (inside city)	$ 2.83
Cedarwood Estates	City of Hickory (inside city)	$ 2.83
Hill-N-Dale	City of Lincolnton	$ 7.70
East Shores	City of Morganton	$ 2.52
Greenfield	City of Mount Airy	$ 7.15
Bett's Brook	City of Newton	$ 2.85
Crestwood	Davidson Water, Inc.	$ 5.30
Lancer Acres	Davidson Water, Inc.	$ 5.30

WATER AND SEWER – RATE INCREASE

Service Area	Water Provider	Usage Charge/ 1,000 gallons
Beard Acres	Davidson Water, Inc.	$ 5.30
Woodlake Development	Harnett County	$ 2.77
Beechwood Cove	Chatham County	$ 7.04
Chatham	Chatham County	$ 7.04
Cole Park Plaza Shopping Center	Chatham County	$10.01
Hidden Valley	Chatham County	$ 7.04
Polks Landing	Chatham County	$ 7.04
Chapel Ridge	Town of Pittsboro	$13.69
Laurel Ridge	Town of Pittsboro	$13.69
The Parks at Meadowview	Town of Pittsboro	$13.69
River Hill Heights	Iredell Water Corp.	$ 2.72

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Service Area	Water Provider	Usage Charge/ 1,000 gallons
Bedford at Flowers Plantation	Johnston County	$ 2.45
Bennett Place	Johnston County	$ 2.45
Chatham	Johnston County	$ 2.45
Cottages at Evergreen	Johnston County	$ 2.45
Cottonfield Village	Johnston County	$ 2.45
Creekside Place	Johnston County	$ 2.45
Eastlake at Flowers Plantation	Johnston County	$ 2.45
Evergreen	Johnston County	$ 2.45
Flowers Crest	Johnston County	$ 2.45
Flowers Shopping Center	Johnston County	$ 2.45
Forge Creek	Johnston County	$ 2.45
Longleaf	Johnston County	$ 2.45
Magnolia	Johnston County	$ 2.45
Magnolia Place/Village	Johnston County	$ 2.45
Mill Creek North	Johnston County	$ 2.45
Mill Creek West	Johnston County	$ 2.45
Neuse Colony	Johnston County	$ 2.45
North Farm	Johnston County	$ 2.45
North Farm Cottages	Johnston County	$ 2.45
North Village	Johnston County	$ 2.45
Parkway Center/Village	Johnston County	$ 2.45
Peachtree	Johnston County	$ 2.45
Pineville Club	Johnston County	$ 2.45
Pineville East	Johnston County	$ 2.45

WATER AND SEWER – RATE INCREASE

Service Area	Water Provider	Usage Charge/ 1,000 gallons
Pineville East Cottages/Palmetto Pl.	Johnston County	$ 2.45
Pineville East Estates	Johnston County	$ 2.45
Pineville West	Johnston County	$ 2.45
Plantation Park	Johnston County	$ 2.45
Plantation Pointe	Johnston County	$ 2.45
Poplar Woods	Johnston County	$ 2.45
River Dell East	Johnston County	$ 2.45
River Dell Townes	Johnston County	$ 2.45
Riverdell Elementary School	Johnston County	$ 2.45
South Plantation	Johnston County	$ 2.45

Service Area	Water Provider	Usage Charge/ 1,000 gallons
South Quarter	Johnston County	$ 2.45
Southgate	Johnston County	$ 2.45
Summerset Place	Johnston County	$ 2.45
Sun Ridge Farms	Johnston County	$ 2.45
Sweetgrass	Johnston County	$ 2.45
The Gardens at Flowers Plantation	Johnston County	$ 2.45
The Meadows	Johnston County	$ 2.45
The Nine	Johnston County	$ 2.45
The Woodlands	Johnston County	$ 2.45
Trillium	Johnston County	$ 2.45
Village at Flowers Plantation	Johnston County	$ 2.45
Walker Woods	Johnston County	$ 2.45
Watson's Mill	Johnston County	$ 2.45
West Ashley	Johnston County	$ 2.45
Whitfield at Flowers Plantation	Johnston County	$ 2.45
Wilders Woods and Extension	Johnston County	$ 2.45
Holly Hills	Town of Forest City	$ 5.95
Pear Meadows	Town of Fuquay-Varina	$ 4.35
Swiss Pine Lake	Town of Spruce Pine	$ 4.93
Brookwood/Lagrange Service Areas		
Kelly Hills	Fayetteville PWC	$ 2.92
Bretton Woods	Fayetteville PWC	$ 2.92
Raintree	Fayetteville PWC	$ 2.92
Colony Village	Fayetteville PWC	$ 2.92
Windsong	Fayetteville PWC	$ 2.92

WATER AND SEWER – RATE INCREASE

Service Area	Water Provider	Usage Charge/ 1,000 gallons
Porter Place	Fayetteville PWC	$ 2.92
Thornwood	Fayetteville PWC	$ 2.92
County Walk	Fayetteville PWC	$ 2.92
Lands Down West	Fayetteville PWC	$ 2.92
S & L Estates	Fayetteville PWC	$ 2.92
Tarleton Plantation	Fayetteville PWC	$ 2.92
Springdale	Fayetteville PWC	$ 2.92
Ridge Manor	Fayetteville PWC	$ 2.92
Forest Lake	Fayetteville PWC	$ 2.92

Service Area	Water Provider	Usage Charge/ 1,000 gallons
Arden Forest	Fayetteville PWC	$ 2.92
Wendemere	Fayetteville PWC	$ 2.92
Jena-Shane	Fayetteville PWC	$ 2.92
Stoney Point	Fayetteville PWC	$ 2.92
Woodland Run	Town of Linden	$ 4.98

APPENDIX A-2
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AQUA NORTH CAROLINA, INC.
PURCHASED SEWER RATES

Aqua North Carolina Service Areas

Monthly Metered Service where bulk service purchased from Charlotte (Park South Station and Parkway Crossing residential and commercial):

Base facility charge, zero usage (based on meter size)	Same as commercial charges listed on Appendix A-1 p 4
Residential and Commercial usage charge	$ 6.45, per 1,000 gallons

Hawthorne at the Greene Apartments and Beaver Farms Subdivision – Mecklenburg County: (See Docket No. W-899, Sub 37 and Docket No. W-218, Sub 357)

Base facilities charge (to be collected and delivered to Carolina Water Service, Inc. of North Carolina[1] for treatment of the wastewater), per month	$ 40.40 per REU[2]

Each apartment building at Hawthorne at the Greene Apartments (formerly Vista Park Apartments) will be considered 92.42% occupied on an ongoing basis for billing purposes as soon as the certificate of occupancy is issued for the apartment building.

Collection service/commodity charge (based on City of Charlotte's master meter reading), per 1,000 gallons	$ 6.11

[1] On August 17, 2016, in Docket No. W-1044, Sub 24, et al., the North Carolina Utilities Commission issued an Order Approving Merger. In accordance with the Order, and pursuant to the Articles of Merger filed with the North Carolina Department of the Secretary of State on August 30, 2016, Bradfield Farms Water Company was merged into Carolina Water Service, Inc. of North Carolina effective August 30, 2016.

[2] Residential Equivalent Unit.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-218, Sub 497, on this the 18th day of December, 2018.

AQUA NORTH CAROLINA, INC.
SCHEDULE OF CONNECTION FEES

SYSTEM NAME	CONNECTION FEE - WATER	CONNECTION FEE - SEWER
Alan Acres	$ 800.00	
Allendale	$ 500.00	
Altice Estates	$ 800.00	
Amy Acres	$ 500.00	
Apple Grove	$ 500.00	
Applegate	$ 500.00	
Arbor Run	$ 500.00	
Armfield, Phases 1A, 1B, 2, 3, 4, 5	$ 500.00	
Ashe Plantation	$ 725.00	
Ashebrook Woods	$ 500.00	
Ashton Park	$ 500.00	
Auburndale	$ 500.00	
Autumn Acres	$ 800.00	
Avocet, Phases1A, 1B, 1C, 1D, 1E, 2, 3,4, 5	$ 500.00	$500.00
Bakersfield	$ 500.00	
Ballard Farm	$ 500.00	
Balls Creek	$ 800.00	
Barkwood Lane	$1,200.00	
Bayberry	$ 800.00	
Beacon Hill	$ 500.00	
Beacon Hills	$ 800.00	
Beau Rivage	$ 969.00	$ 822.00
Beau Rivage Market Place Shopping Center	$1,000.00	
Beechwood Cove	$ 500.00	
Belews Landing	$ 500.00	
Bella Port		$2,500.00
Bells Crossing, Phases 1 ,2, 3, 4	$1,000.00	
Bennett Place		$1,000.00
Berklee Reserve	$ 500.00	
Bethel Forest	$ 500.00	
Betts Brook	$ 500.00	
Beverly Acres	$ 800.00	

WATER AND SEWER – RATE INCREASE

SYSTEM NAME	CONNECTION FEE - WATER	CONNECTION FEE - SEWER
Bexley Place	$ 500.00	
Birkhaven	$ 500.00	
Blue Water Cove	$ 500.00	
Bogue Watch		$2,500.00
Bonaire	$ 500.00	
Brafford Farms	$ 800.00	
Briar Creek	$ 500.00	
Brickfield	$ 400.00	
Bridgeport	$ 800.00	
SYSTEM NAME	**CONNECTION FEE - WATER**	**CONNECTION FEE - SEWER**
Bridle Wood	$ 500.00	
Brights Creek	$ 500.00	$ 500.00
Brinley's Cove	$ 500.00	
Brook Forest	$ 800.00	
Buck Springs Plantation	$1,000.00	
Cameron Point	$ 500.00	
Candy Creek	$ 500.00	
Cane Bay	$ 500.00	$ 500.00
Cannonsgate		$2,500.00
Canterbury Trails	$ 500.00	
Capeside Village	$ 750.00	$1,000.00
Carmel Hills	$ 800.00	
Carmel Park	$ 800.00	
Cassimir Commons	$ 750.00	$1,000.00
Castle Bay	$ 500.00	$ 500.00
Castlewood	$ 800.00	
Catawba Shores	$ 800.00	
Cedar Chase	$ 500.00	
Cedar Creek	$ 500.00	
Cedar Grove	$ 800.00	
Cedar Valley	$ 800.00	
Chapelwood Acres	$ 800.00	
Charles Place at Arbor Run	$ 500.00	
Chatham	$ 500.00	
Clarendon Gardens (includes main extension)	$1,125.00	
Cliftwood West	$ 800.00	

WATER AND SEWER – RATE INCREASE

SYSTEM NAME	CONNECTION FEE - WATER	CONNECTION FEE - SEWER
Clear Meadow	$ 175.00	
Clubview Estates I	$ 800.00	
Collybrooke, Phases 1, 1A, 2	$ 500.00	
Colvard Farms, Phase 9		$ 500.00
Copperfield	$ 800.00	
Coral Ridge	$1,000.00	$2,500.00
Country Acres	$ 800.00	
Country Acres MHP	$ 800.00	
Country Crossing, Phases I, II, and III	$ 750.00	
Country Crossing, Phases IV and V	$ 670.50	
Country Knolls	$ 800.00	
Country Meadows	$ 800.00	
Country Valley Ext (Lots 7G, 8G, 9G, 12E, 13E, 14E, 15E, 16E, 17F)	$2,500.00	
Country Woods	$ 800.00	
Countryside	$ 500.00	
Crabtree II	$ 500.00	
Craig Gardens	$ 800.00	
Creedmoor Village Shopping Center	$ 500.00	
Creekside	$ 500.00	
Creekside Shores	$1,000.00	
Crestview (Rowan County)	$ 500.00	
Crestview (Cabarrus County)	$ 800.00	
Cross Creek	$ 500.00	
Crutchfield Farms	$ 500.00	
Dalewood/Monteray	$ 800.00	
Deer Path	$ 500.00	
Deerwood	$ 500.00	
Dolphin Bay		$1,000.00
Dorsett Downs	$ 500.00	
Eagle Landing	$ 500.00	
East Bank	$ 750.00	$1,000.00
East Chestnut	$ 800.00	
East Gaston MHP	$ 500.00	
Eastlake	$ 850.00	$1,000.00
Edgewood Acres I & II	$ 800.00	
El Camino	$ 800.00	

WATER AND SEWER – RATE INCREASE

SYSTEM NAME	CONNECTION FEE - WATER	CONNECTION FEE - SEWER
Emerald Plantation		Actual Cost
Enoch Turner	$ 500.00	
Epes Trucking	$ 500.00	
Estates at Meadow Ridge	$ 500.00	
Ethan's Gate	$ 500.00	
Ethan's Glen	$ 500.00	
Fairfax	$ 800.00	
Fairview Park	$ 800.00	
Fairview Wooded Acres	$ 800.00	
Falls Creek	$ 500.00	
Fallscrest	$ 800.00	
Farmwood	$ 800.00	
Ferguson Village	$ 500.00	
Fleetwood Acres I	$ 800.00	
Fleetwood Falls and Fleetwood Falls, Sect 15	$ 500.00	
Fontain Village	$ 800.00	
Forest Acres	$ 800.00	
Forest Cove	$ 800.00	
Forest Pines	$ 500.00	
Forest Ridge	$ 500.00	
Fountain Trace	$ 800.00	
Fox Fire	$ 800.00	
Fox Ridge	$ 800.00	
Fox Run	$ 800.00	
Foxbury	$ 500.00	
Foxbury Meadows	$ 500.00	
Freemont Park	$ 500.00	
Gallagher Trails	$ 800.00	
Gates at Ethan's Glen	$ 500.00	
Glennburn (Sub 385)	$1,500.00	
Glencroft	$ 500.00	
Governors Club		$4,500.00
Governors Forest		$4,500.00
Governors Village		$4,500.00
Grayson Park	$ 500.00	
Graystone Forest	$ 500.00	$ 350.00

WATER AND SEWER – RATE INCREASE

SYSTEM NAME	CONNECTION FEE - WATER	CONNECTION FEE - SEWER
Green Acres MHP	$ 800.00	
Green Meadows	$ 800.00	
Greenwood	$ 500.00	
Hanover Downs	$ 800.00	
Happy Valley	$ 500.00	
Hartman Farms	$ 500.00	
Hasentree, Phases 1-3, 4A, 4B, 4C, 5, 6A, 6B, 6C, 7, 8, 9, 10, 11, 15A, 15B, 15E		$2,500.00
Heartwood	$ 500.00	
Heather Acres	$ 800.00	
Heather Glen	$ 200.00	
Heritage Farms	$ 500.00	
Heritage West	$ 500.00	
Herman Acres	$ 800.00	
Hickory Creek (Houses on Basswood Way Only)	$ 500.00	
Hickory Ridge	$ 500.00	
Hidden Creek	$ 500.00	
Hidden Hills	$ 500.00	
Hidden Valley (Chatham County)	$ 500.00	
Hidden Valley (Catawba County)	$ 800.00	
High Grove, Phase 3	$ 500.00	
High Meadows	$ 725.00	
Hillsboro	$ 500.00	
Hilltop	$ 500.00	
Holiday Hills	$ 500.00	
Hollywood Acres	$ 800.00	
Homestead-Catawba	$ 500.00	
Hoyles Creek	$ 500.00	
Huntcliff	$ 500.00	
Hunters Mark	$ 500.00	
Hunters Ridge	$ 500.00	
Hunting Ridge	$ 500.00	
Huntley Glen Townhomes, Phase 2	$ 700.00	
Huntwood	$ 500.00	
Idlewild Park	$ 800.00	
Ingram Estates	$ 500.00	
Inlet Point Harbor	$ 750.00	$1,000.00

WATER AND SEWER – RATE INCREASE

SYSTEM NAME	CONNECTION FEE - WATER	CONNECTION FEE - SEWER
Inlet Point Harbor Extension	$1,000.00	
Inlet Watch	$ 750.00	$1,000.00
Inlet Watch-irrigation meters	$ 300.00	
Interlaken	$ 500.00	
Island Bridge Way	$ 750.00	$1,000.00
Jack's Landing	$1,000.00	
Jamestowne	$ 500.00	
Keltic Meadows	$ 800.00	
Kendale Woods	$ 940.00	
Kimberly Courts	$ 500.00	
Kings Acres	$ 500.00	
Knob Creek	$ 500.00	
Knolls Phases I and II only	$ 500.00	
Knollview	$ 500.00	
Knollwood	$1,500.00	
Knoxhaven	$ 500.00	
Kynwood	$ 500.00	
Lakeridge	$ 500.00	
Lakewood	$ 800.00	
Lamar Acres	$ 800.00	
Lancer Acres	$ 500.00	
Laurel Acres	$ 500.00	
Laurel Woods	$ 500.00	
Lea Landing	$1,000.00	$2,500.00
Lennox Woods	$ 500.00	
Lighthouse Village	$ 750.00	$1,000.00
Linville Oaks	$ 500.00	
Little River Run	$ 800.00	
Long Shoals	$ 800.00	
Love Point	$ 500.00	
Lynmore	$ 800.00	
MacGregor Downs	$ 800.00	
Magnolia Place	$ 850.00	$1,000.00
Magnolia Springs	$ 800.00	
Mallard Crossing	$ 500.00	
Mallardhead	$ 500.00	
Maplecrest	$ 800.00	

WATER AND SEWER – RATE INCREASE

SYSTEM NAME	CONNECTION FEE - WATER	CONNECTION FEE - SEWER
Mariners Pointe, Phase 1	$ 450.00	
Mar-Lyn Forest	$ 500.00	
Meadow Creek	$ 500.00	
Meadow Ridge	$ 500.00	
Meadow Run	$ 500.00	
Meadowbrook	$ 500.00	
Mill Creek Landing	$1,000.00	
Mineral Springs	$ 500.00	
Monticello Estates	$ 500.00	
Moratuck Manor	$1,000.00	
Morningside Park	$ 800.00	
Morris Grove	$ 500.00	
Morristown	$1,000.00	
Moss Haven	$ 800.00	
Mount Vernon Crossing, Phase 3	$ 500.00	
Mountain Creek	$ 500.00	
Mountain Point	$ 350.00	
Mountainbrook	$ 800.00	
Murray Hills	$ 800.00	
Myrtlewood	$ 800.00	
Nantucket Village	$ 500.00	
Nautical Green	$ 750.00	$1,000.00
Neuse Colony	$2,000.00	$1,000.00
Neuse River Village	$ 500.00	$ 500.00
New Chartwell	$ 500.00	
Normandy Glen	$ 500.00	
Oak Harbor (excludes Knox Realty)	$1,750.00	
Oak Hill	$ 800.00	
Oakley Park	$ 800.00	
Old Cape Cod	$ 750.00	$1,000.00
Old Providence	$ 800.00	
Paradise Point	$ 800.00	
Park South Station	$ 700.00	
Parkway Crossing	$ 700.00	
Parkwood	$ 500.00	

WATER AND SEWER – RATE INCREASE

SYSTEM NAME	CONNECTION FEE - WATER	CONNECTION FEE - SEWER
Peabody Forest	$ 500.00	
Pearman Estates	$ 500.00	
Pepper Ridge	$ 500.00	
Pheasant Ridge	$ 500.00	
Phillips Landing	$ 800.00	
Piedmont Estates	$ 500.00	
Pilot's Ridge, Lots 22 through 29	$1,000.00	
Pine Knolls	$ 500.00	
Pine Meadows	$ 500.00	
Pineview	$ 500.00	
Pinewood Acres	$ 800.00	
Pleasant Gardens	$ 500.00	
Polk's Landing	$ 500.00	
Polk's Trail	$ 500.00	
Ponderosa	$ 500.00	
Providence Acres	$ 800.00	
Providence North	$ 500.00	
Quail Meadows	$ 500.00	
Quail Oaks	$ 500.00	
Quail's Nest	$ 500.00	
Raintree	$ 800.00	
Red Mountain	$ 500.00	
Regency Village	$ 500.00	
Richwood Acres	$ 500.00	
Ridgecrest	$ 500.00	
Ridgeview Park	$ 800.00	
Ridgeway Courts	$ 500.00	
Ridgewood	$ 500.00	
River Oaks (Guilford County)	$ 500.00	
River Oaks (New Hanover County)	$ 750.00	
River Oaks, Phase 8 (New Hanover County)	$1,000.00	$2,500.00
River Park	$1,500.00	$10.00 / gpd of capacity
River Point at Beau Rivage	$ 969.00	$ 822.00
River Ridge Run	$ 500.00	
River Run	$ 500.00	

WATER AND SEWER – RATE INCREASE

SYSTEM NAME	CONNECTION FEE - WATER	CONNECTION FEE - SEWER
Riverside at Oak Ridge	$ 500.00	
Riverton Place	$ 800.00	
Riverview	$ 500.00	
Riverwoods	$ 800.00	
Robinfield	$ 800.00	
Roland Place	$ 750.00	$1,000.00
Roland Place extension	$1,000.00	
Rolling Hills	$ 500.00	
Rolling Meadows	$ 800.00	
Round Tree Ridge		$2,500.00
Rustic Trials	$ 800.00	
Saddlewood	$ 800.00	
Sailors Lair	$1,000.00	$2,500.00
Sanford's Creek	$ 500.00	
Seabreeze	$ 750.00	$1,000.00
Seabreeze Sound Extension	$1,000.00	$2,500.00
Seagate I	$ 500.00	
Seagate IV	$ 500.00	
Sedgley Abby	$ 750.00	$1,000.00
Shade Tree	$ 500.00	
Shadow Oaks	$ 500.00	
Shangri-la	$ 800.00	
Shaw Hill Estates	$ 500.00	
Sherwood Forest (Catawba County)	$ 500.00	
Shiloh	$ 500.00	
Shipwatch	$ 750.00	$1,000.00
Silverstone	$ 800.00	
Skyland Drive	$ 800.00	
Smoke Ridge	$ 500.00	
Smokerise	$ 500.00	
Snow Creek	$ 500.00	
Sopanos Point	$ 750.00	$1,000.00
South Bourne	$ 500.00	
South Forest	$ 800.00	
South Fork (Catawba)	$ 500.00	
South Fork (Gaston)	$ 800.00	
South Hill	$ 800.00	

WATER AND SEWER – RATE INCREASE

SYSTEM NAME	CONNECTION FEE - WATER	CONNECTION FEE - SEWER
South Hill Estates	$ 800.00	
South Point Landing	$ 800.00	
Southampton	$ 800.00	
Southgate	$ 800.00	
Southwood	$ 800.00	
Spencer Road Acres	$ 800.00	
Spinnaker Bay	$ 800.00	
Spinnaker Pointe	$1,000.00	
Spring Hill/Springdale	$ 800.00	
Spring Shores	$ 800.00	
Spring Valley	$ 800.00	
Springdale	$ 500.00	
Springfield Estates	$ 500.00	
Springhaven	$ 800.00	
Sprinkle	$ 500.00	
Stanleystone Estates	$1,000.00	
Starland Park	$ 800.00	
Sterlingshire	$ 500.00	
Stonehouse Acres	$1,000.00	
Stoneridge	$ 500.00	
Stoney Brook	$ 800.00	
Sturbridge Village	$ 500.00	
Summerfield Farms	$ 500.00	
Summerwind	$ 500.00	
Sunset Bay (3 digit lot #s on Roundstone Road)	$2,500.00	
Sunset Hills	$ 800.00	
Sunset Park	$ 800.00	
Swiss Pine Lake	$ 800.00	
Tablerock	$ 800.00	
Telfair Forrest	$ 750.00	$1,000.00
The Cape, Section A	$ 750.00	$1,000.00
The Cape, Section B	$ 750.00	$1,000.00
The Gardens at Flowers	$ 850.00	$1,000.00
The Reserve at Falls Lake, Phase I	$ 500.00	
The Sanctuary	$ 750.00	$1,000.00
The Village at Motts Landing	$1,000.00	
The Vineyards	$ 500.00	

WATER AND SEWER – RATE INCREASE

SYSTEM NAME	CONNECTION FEE - WATER	CONNECTION FEE - SEWER
Thornton Ridge	$ 400.00	
Tidelands on the River	$1,000.00	
Timberlake	$ 400.00	
Timberline	$ 500.00	
Timberline Shores	$1,000.00	
Tralee Place	$1,000.00	
Triple Lakes	$ 500.00	
Tuxedo	$ 800.00	
Twelve Oaks	$ 500.00	
Twelve Oaks Cadet Drive Extension	$1,700.00	
Twin Creek	$3,000.00	
Twin Oaks	$ 500.00	
Valley Acres	$ 500.00	
Valley Dale	$ 500.00	
Village Woods	$ 500.00	
Walker Estates	$ 500.00	
Waterford		$2,500.00
Watts	$ 800.00	
Weatherstone	$ 350.00	
Wellington	$ 500.00	
Wesley Acres	$ 800.00	
West View at River Oaks	$1,000.00	$2,500.00
Westfall – 100 foot wide lots (47 lots)		$2,750.00
Westfall – 80 foot wide lots (60 lots)		$2,565.00
Westfall – 60 foot wide lots (69 lots)		$2,250.00
Westfall – Estate Lots (64 lots)		$3,150.00
Westfall – Amenities		$2,000.00
Westside Hills	$ 500.00	
Willard Run/San Siro	$ 500.00	
Willow Creek		$ 500.00
Willow Glen at Beau Rivage	$ 500.00	$ 500.00
Willow Oaks	$ 800.00	
Wilson Farm	$ 500.00	
Wimbledon	$1,500.00	
Winding Forest	$ 500.00	
Windspray	$ 750.00	$1,000.00
Windswept, Phase 1	$ 750.00	$1,000.00

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SYSTEM NAME	CONNECTION FEE - WATER	CONNECTION FEE - SEWER
Windswept, Phase 2 & 3		$ 500.00
Windwood Acres	$ 800.00	
Woodbridge	$ 500.00	
Woodford (Hawks Ridge)	$ 500.00	
Woodlake	$ 800.00	$ 800.00
Woodlake – Irrigation Meter	$ 300.00	
Woodland Hills	$ 500.00	
Woodland Shores	$1,000.00	
Woodlawn	$ 800.00	
Woodleigh	$ 800.00	
Wright Beaver	$ 500.00	
Yorkwood Park	$ 800.00	

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-218, Sub 497, on this the 18th day of December, 2018.

APPENDIX A-4

AQUA NORTH CAROLINA, INC.
WATER AND SEWER SYSTEM IMPROVEMENT CHARGES

WATER SYSTEM IMPROVEMENT CHARGE

All Aqua NC water systems except as noted below	0.00% 1/ and 2/
Water systems in Brookwood and LaGrange service areas	0.00% 1/ and 2/
Water systems in Fairways and Beau Rivage service areas	0.00% 1/ and 2/

SEWER SYSTEM IMPROVEMENT CHARGE

All Aqua NC sewer systems except as noted below	0.00% 1/ and 3/
Sewer systems in Fairways and Beau Rivage service areas	0.00% 1/ and 3/

1/ Reset to zero pursuant to the Commission's Order in Docket No. W-218, Sub 497.

2/ Upon approval by further order of the Commission, the Water System Improvement Charge will be applied to the total water utility bill of each customer under the Company's applicable rates and charges.

3/ Upon approval by further order of the Commission, the Sewer System Improvement Charge will be applied to the total sewer utility bill of each customer under the Company's applicable rates and charges.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-218, Sub 497, on this the 18th day of December, 2018.

**STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH**

DOCKET NO. W-218, SUB 497

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Aqua North Carolina, Inc., 202 MacKenan Court, Cary, North Carolina 27511, for Authority to Increase Rates for Water and Sewer Utility Service in All of Its Service Areas in North Carolina	NOTICE TO CUSTOMERS IN AQUA NORTH CAROLINA SERVICE AREAS

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing Aqua North Carolina, Inc. (Aqua NC), to increase its rates for water and sewer service in its service areas in North Carolina. The new approved water and sewer rates for Aqua NC customers, excluding the Brookwood / LaGrange service areas in Cumberland and Hoke Counties and the Fairways / Beau Rivage service areas in New Hanover County, are as follows:

WATER UTILITY SERVICE

Monthly Metered Service (Residential and Commercial customers)

Base charge (zero usage, based on meter size)

<1" meter	$ 19.25
1" meter	$ 48.13
1-1/2" meter	$ 96.25
2" meter	$154.00
3" meter	$288.75
4" meter	$481.25
6" meter	$962.50

Usage charge, per 1,000 gallons $ 5.83

Bulk Purchased Water Systems
Base monthly charge same as above

Usage charge per 1,000 gallons, where water purchased for resale as shown below:

Service Area	Water Provider	Usage Charge
Twin Creeks	City of Asheville	$ 4.26
Heather Glen and Highland	City of Belmont	$14.40
Southpoint Landing	City of Belmont	$14.40
Park South	City of Charlotte	$ 1.81
Parkway Crossing	City of Charlotte	$ 1.81
Springhill / Springdale	City of Concord	$ 5.11
Hoopers Valley	City of Hendersonville	$ 3.06
Crystal Creek	City of Hendersonville	$ 3.06
Rambling Ridge	City of Hendersonville	$ 3.06
Brookwood	City of Hickory (outside city)	$ 5.04
Heritage Farms	City of Hickory (inside city)	$ 2.83
Cedarwood Estates	City of Hickory (inside city)	$ 2.83
Hill-N-Dale	City of Lincolnton	$ 7.70
East Shores	City of Morganton	$ 2.52
Greenfield	City of Mount Airy	$ 7.15
Bett's Brook	City of Newton	$ 2.85
Crestwood	Davidson Water, Inc.	$ 5.30
Lancer Acres	Davidson Water, Inc.	$ 5.30
Beard Acres	Davidson Water, Inc.	$ 5.30
Woodlake Development	Harnett County	$ 2.77
Beechwood Cove	Chatham County	$ 7.04
Chatham	Chatham County	$ 7.04
Cole Park Plaza Shopping Center	Chatham County	$10.01
Hidden Valley	Chatham County	$ 7.04
Polks Landing	Chatham County	$ 7.04
Chapel Ridge	Town of Pittsboro	$13.69
Laurel Ridge	Town of Pittsboro	$13.69
The Parks at Meadowview	Town of Pittsboro	$13.69
River Hill Heights	Iredell Water Corp.	$ 2.72

WATER AND SEWER – RATE INCREASE

Service Area	Water Provider	Usage Charge
Bedford at Flowers Plantation	Johnston County	$ 2.45
Bennett Place	Johnston County	$ 2.45
Chatham	Johnston County	$ 2.45
Cottages at Evergreen	Johnston County	$ 2.45
Cottonfield Village	Johnston County	$ 2.45
Creekside Place	Johnston County	$ 2.45
Eastlake at Flowers Plantation	Johnston County	$ 2.45
Evergreen	Johnston County	$ 2.45
Flowers Crest	Johnston County	$ 2.45
Flowers Shopping Center	Johnston County	$ 2.45
Forge Creek	Johnston County	$ 2.45
Longleaf	Johnston County	$ 2.45
Magnolia	Johnston County	$ 2.45
Magnolia Place/Village	Johnston County	$ 2.45
Mill Creek North	Johnston County	$ 2.45
Mill Creek West	Johnston County	$ 2.45
Neuse Colony	Johnston County	$ 2.45
North Farm	Johnston County	$ 2.45
North Farm Cottages	Johnston County	$ 2.45
North Village	Johnston County	$ 2.45
Parkway Center/Village	Johnston County	$ 2.45
Peachtree	Johnston County	$ 2.45
Pineville Club	Johnston County	$ 2.45
Pineville East	Johnston County	$ 2.45
Pineville East Cottages/Palmetto Pl.	Johnston County	$ 2.45
Pineville East Estates	Johnston County	$ 2.45
Pineville West	Johnston County	$ 2.45
Plantation Park	Johnston County	$ 2.45
Plantation Pointe	Johnston County	$ 2.45
Poplar Woods	Johnston County	$ 2.45
River Dell East	Johnston County	$ 2.45
River Dell Townes	Johnston County	$ 2.45
Riverdell Elementary School	Johnston County	$ 2.45
South Plantation	Johnston County	$ 2.45
South Quarter	Johnston County	$ 2.45
Southgate	Johnston County	$ 2.45
Summerset Place	Johnston County	$ 2.45
Sun Ridge Farms	Johnston County	$ 2.45
Sweetgrass	Johnston County	$ 2.45
The Gardens at Flowers Plantation	Johnston County	$ 2.45

WATER AND SEWER – RATE INCREASE

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Service Area	Water Provider	Usage Charge
The Meadows	Johnston County	$ 2.45
The Nine	Johnston County	$ 2.45
The Woodlands	Johnston County	$ 2.45
Trillium	Johnston County	$ 2.45
Village at Flowers Plantation	Johnston County	$ 2.45
Walker Woods	Johnston County	$ 2.45
Watson's Mill	Johnston County	$ 2.45
West Ashley	Johnston County	$ 2.45
Whitfield at Flowers Plantation	Johnston County	$ 2.45
Wilders Woods and Extension	Johnston County	$ 2.45
Holly Hills	Town of Forest City	$ 5.95
Pear Meadows	Town of Fuquay-Varina	$ 4.35
Swiss Pine Lake	Town of Spruce Pine	$ 4.93

Monthly Unmetered service (flat rate)

Residential customers	$ 39.66
Commercial customers (per *REU)	$ 67.42

*(REU = Residential Equivalent Unit)

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PAGE 5 OF 7

SEWER UTILITY SERVICE

Monthly Unmetered Service (flat rate)
All service areas unless noted differently below

Residential customers	$ 72.04
Commercial customers (per *REU)	$ 100.86

*(REU = Residential Equivalent Unit)

STEP system flat rate (Monticello, Holly Brook, Saddleridge)	$ 32.00

Commercial Monthly Metered Service and all the Park South Station and Parkway Crossing Service Areas (based on metered water usage)

WATER AND SEWER – RATE INCREASE

Base facility charge (zero usage, based on water meter size)
All service areas unless noted differently below

<1" meter	$ 26.11
1" meter	$ 65.28
1½" meter	$ 130.55
2" meter	$ 208.88
3" meter	$ 391.65
4" meter	$ 652.75
6" meter	$1,305.50

Usage charge, per 1,000 gallons $ 8.92
All service areas unless noted differently below

<u>Park South Station and Parkway Crossing Service Areas</u>

Base facility charge:	As shown above
Usage charge/1,000 gallons	$ 6.45

<u>Hawthorne Green (formerly Vista Park Apartments)</u>

Base facility charge/REU	$ 40.40
Usage charge, per 1,000 gallons	$ 6.11

IMPACT ON AVERAGE RESIDENTIAL BILL

The impact on the average monthly residential bill including the reset of the water and sewer system improvement charge (WSIC and SSIC) is as follows:

	Water	Sewer
Average bill under prior rates	$47.05	$65.57
Average bill under approved rates	$48.23	$72.04

The average monthly residential bills are based on the uniform rates for non-purchased water and sewer systems based on an average usage of 4,971 gallons per month. The average residential bills for the bulk purchased water and sewer systems will vary.

WATER AND SEWER – RATE INCREASE

RATE ADJUSTMENT MECHANISM:

The Commission-authorized WSIC and SSIC rate adjustment mechanisms continue in effect. These charges have been reset to zero in the Docket No. W-218, Sub 497 rate case, but Aqua NC may, under the Rules and Regulations of the Commission, apply for a rate surcharge on May 1, 2019, to become effective July 1, 2019. The WSIC/SSIC mechanisms are designed to recover, between rate case proceedings, the costs associated with investment in certain completed, eligible projects for water and sewer system improvements. The WSIC/SSIC mechanisms are subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC/SSIC mechanisms may not exceed 5% of the total annual service revenues approved by the Commission in this general rate case proceeding. Additional information regarding the WSIC/SSIC mechanisms is contained in the Commission's Order and can be accessed from the Commission's website at www.ncuc.net, under Docket Information, using the Docket Search feature for docket number "W-218 Sub 497" or W-218 Sub 497A".

CREDIT/REFUNDS DUE TO REDUCTIONS IN CORPORATE FEDERAL AND STATE INCOME TAX RATES:

On December 22, 2017, President Donald J. Trump signed into law the Tax Cuts and Jobs Act (The Tax Act), which among other things, reduced the federal corporate income tax rate from 35% to 21%, effective for taxable years beginning after December 31, 2017. In the present rate case proceeding, the Commission reduced Aqua NC's revenue requirement to reflect the reduction in the federal corporate income tax rate from 35% to 21%, on the Company's ongoing federal

income tax expense. Further, the Commission is requiring that Aqua NC refund to its customers the overcollection of federal income taxes related to the decrease in the federal corporate income tax rate for the period beginning January 1, 2018, and corresponding interest, through a surcharge credit for a one-year period beginning with the effective date of the new rates.

With respect to excess deferred income taxes (EDIT) resulting from reductions in the corporate federal and state income tax rates, the Commission is requiring that: (a) Aqua NC's Protected Federal EDIT shall be flowed back to customers following the tax normalization rules utilizing the average rate assumption method (ARAM) as required by the rules of the Internal Revenue Service; (b) Aqua NC's Unprotected Federal EDIT shall be returned to ratepayers through a levelized rider over a period of three years; and (c) Aqua NC's State EDIT shall be returned to customers through a levelized rider that will expire at the end of a three-year period.

WATER AND SEWER – RATE INCREASE

Aqua NC will provide the applicable dollar amounts concerning (1) the one-year surcharge credit and (2) the federal and state EDIT riders (refunds) shown as separate line items on individual customers' monthly bills, along with explanatory information.

ISSUED BY ORDER OF THE COMMISSION.
This the 18th day of December, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

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PAGE 1 OF 4

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-218, SUB 497

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Aqua North Carolina, Inc.,	)	
202 MacKenan Court, Cary, North Carolina	)	NOTICE TO CUSTOMERS IN
27511, for Authority to Increase Rates for Water	)	BROOKWOOD / LAGRANGE
and Sewer Utility Service in All of Its Service	)	SERVICE AREAS
Areas in North Carolina	)	

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing Aqua North Carolina, Inc. (Aqua NC), to increase its rates for water service in its Brookwood and LaGrange service areas in Cumberland and Hoke Counties. The new approved water rates are as follows:

<u>Monthly Metered Service (Residential and Commercial customers)</u>

Base charge, per month (zero usage, based on meter size)	
<1" meter	$ 14.03
1" meter	$ 35.08
1½" meter	$ 70.15
2" meter	$ 112.24
3" meter	$ 210.45
4" meter	$ 350.75
6" meter	$ 701.50

WATER AND SEWER – RATE INCREASE

Usage charge, per 1,000 gallons All service areas unless noted differently below	$ 3.76

Bulk Purchased Water Systems
Base monthly charge same as above

Usage charge per 1,000 gallons, where water purchased for resale as shown below

Service Area	Water Provider	Usage Charge
Kelly Hills	Fayetteville PWC	$ 2.92
Bretton Woods	Fayetteville PWC	$ 2.92
Raintree	Fayetteville PWC	$ 2.92
Colony Village	Fayetteville PWC	$ 2.92
Windsong	Fayetteville PWC	$ 2.92
Porter Place	Fayetteville PWC	$ 2.92
Thornwood	Fayetteville PWC	$ 2.92
County Walk	Fayetteville PWC	$ 2.92
Lands Down West	Fayetteville PWC	$ 2.92
S & L Estates	Fayetteville PWC	$ 2.92
Tarleton Plantation	Fayetteville PWC	$ 2.92
Springdale	Fayetteville PWC	$ 2.92
Ridge Manor	Fayetteville PWC	$ 2.92
Forest Lake	Fayetteville PWC	$ 2.92
Arden Forest	Fayetteville PWC	$ 2.92
Wendemere	Fayetteville PWC	$ 2.92
Jena-Shane	Fayetteville PWC	$ 2.92
Stoney Point	Fayetteville PWC	$ 2.92
Woodland Run	Town of Linden	$ 4.98

Monthly Unmetered Service/REU (flat rate)

Residential Rate	$ 33.17
Commercial customers (per *REU)	$ 56.39

*(REU = Residential Equivalent Unit)

WATER AND SEWER – RATE INCREASE

IMPACT ON AVERAGE RESIDENTIAL BILL

The impact on the average monthly residential bill including the reset of the WSIC is as follows:

	Water
Average bill under prior rates	$30.17
Average bill under approved rates	$33.98

The average monthly residential bills are based on the rates for non-purchased water systems based on an average usage of 5,306 gallons per month. The average residential bills for the bulk purchased water systems will vary.

RATE ADJUSTMENT MECHANISM:

The Commission-authorized WSIC rate adjustment mechanism continues in effect. This surcharge has been reset to zero in the Docket No. W-218, Sub 497 rate case, but Aqua NC may, under the Rules and Regulations of the Commission, apply for a rate surcharge on May 1, 2019, to become effective July 1, 2019. The WSIC mechanism is designed to recover, between rate case proceedings, the costs associated with investment in certain completed, eligible projects for water and sewer system improvements. The WSIC mechanism is subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC mechanism may not exceed 5% of the total annual service revenues approved by the Commission in this general rate case proceeding. Additional information regarding the WSIC mechanism is contained in the Commission's Order and can be accessed from the Commission's website at www.ncuc.net, under Docket Information, using the Docket Search feature for docket number "W-218 Sub 497" or W-218 Sub 497A".

CREDIT/REFUNDS DUE TO REDUCTIONS IN CORPORATE FEDERAL AND STATE INCOME TAX RATES:

On December 22, 2017, President Donald J. Trump signed into law the Tax Cuts and Jobs Act (The Tax Act), which among other things, reduced the federal corporate income tax rate from 35% to 21%, effective for taxable years beginning after December 31, 2017. In the present rate case proceeding, the Commission reduced Aqua NC's revenue requirement to reflect the reduction in the federal corporate income tax rate from 35% to 21%, on the Company's ongoing federal income tax expense. Further, the Commission is requiring that Aqua NC refund to its customers the overcollection of federal income taxes related to the decrease in the federal corporate income tax rate for the period beginning January 1, 2018, and corresponding interest, through a surcharge credit for a one-year period beginning with the effective date of the new rates.

With respect to excess deferred income taxes (EDIT) resulting from reductions in the corporate federal and state income tax rates, the Commission is requiring that: (a) Aqua NC's Protected Federal EDIT shall be flowed back to customers following the tax normalization rules utilizing the average rate assumption method (ARAM) as required by the rules of the Internal Revenue Service; (b) Aqua NC's Unprotected Federal EDIT shall be returned to ratepayers through a levelized rider over a period of three years; and (c) Aqua NC's State EDIT shall be returned to customers through a levelized rider that will expire at the end of a three-year period.

APPENDIX B-2
PAGE 4 OF 4

Aqua NC will provide the applicable dollar amounts concerning (1) the one-year surcharge credit and (2) the federal and state EDIT riders (refunds) shown as separate line items on individual customers' monthly bills, along with explanatory information.

ISSUED BY ORDER OF THE COMMISSION.
This the 18th day of December, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

APPENDIX B-3
PAGE 1 OF 4

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-218, SUB 497

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Aqua North Carolina, Inc.,	)	
202 MacKenan Court, Cary, North Carolina 27511,	)	NOTICE TO CUSTOMERS IN
for Authority to Increase Rates for Water and	)	FAIRWAYS AND BEAU RIVAGE
Sewer Utility Service in All of Its Service Areas	)	SERVICE AREAS
in North Carolina	)	

WATER AND SEWER – RATE INCREASE

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing Aqua North Carolina, Inc. (Aqua NC), to decrease its rates for water service and increase its rates for sewer service in its Fairways and Beau Rivage service areas in New Hanover County. The new approved water and sewer rates are as follows:

WATER UTILITY SERVICE

Monthly Metered Service (Residential and Commercial customers)

Base charge, per month (zero usage, based on meter size)	
<1" meter	$ 8.36
1" meter	$ 20.90
1½" meter	$ 41.80
2" meter	$ 66.88
3" meter	$ 125.40
4" meter	$ 209.00
6" meter	$ 418.00
Usage charge, per 1,000 gallons	$ 1.53

SEWER UTILITY SERVICE

Monthly Unmetered Service (flat rate)

Residential customers	$ 58.56
Commercial customers (per *REU)	$ 81.98
*(REU = Residential Equivalent Unit)	

Commercial Monthly Metered Service (based on metered water usage)

Base facility charge (zero usage, based on water meter size)

<1" meter	$ 20.72
1" meter	$ 51.80
1 1/2" meter	$ 103.60
2" meter	$ 165.76
3" meter	$ 310.80
4" meter	$ 518.00
6" meter	$1,036.00

Usage charge, per 1,000 gallons $ 9.46

IMPACT ON AVERAGE RESIDENTIAL BILL

The impact on the average monthly residential bill including the reset of the WSIC and SSIC is as follows:

	Water	Flat Rate Sewer
Average bill under prior rates	$19.26	$38.09
Average bill under approved rates	$19.13	$58.56

The average monthly residential bills listed above are based on an average usage of 7,042 gallons per month.

RATE ADJUSTMENT MECHANISM:

The Commission-authorized WSIC and SSIC rate adjustment mechanisms continue in effect. These charges have been reset to zero in the Docket No. W-218, Sub 497 rate case, but Aqua NC may, under the Rules and Regulations of the Commission, apply for a rate surcharge on May 1, 2019, to become effective July 1, 2019. The WSIC/SSIC mechanisms are designed to recover, between rate case proceedings, the costs associated with investment in certain completed, eligible projects for water and sewer system improvements. The WSIC/SSIC mechanisms are subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC/SSIC mechanisms may not exceed 5% of the total annual service revenues approved by the Commission in this general rate case proceeding. Additional information regarding the WSIC/SSIC mechanisms is contained in the Commission's Order and can be accessed from the Commission's website at www.ncuc.net, under Docket Information, using the Docket Search feature for docket number "W-218 Sub 497" or W-218 Sub 497A".

CREDIT/REFUNDS DUE TO REDUCTIONS IN CORPORATE FEDERAL AND STATE INCOME TAX RATES:

On December 22, 2017, President Donald J. Trump signed into law the Tax Cuts and Jobs Act (The Tax Act), which among other things, reduced the federal corporate income tax rate from 35% to 21%, effective for taxable years beginning after December 31, 2017. In the present rate case proceeding, the Commission reduced Aqua NC's revenue requirement to reflect the reduction in the federal corporate income tax rate from 35% to 21%, on the Company's ongoing federal income tax expense. Further, the Commission is requiring that Aqua NC refund to its customers the overcollection of federal income taxes related to the decrease in the federal corporate income tax rate for the period beginning January 1, 2018, and corresponding interest, through a surcharge credit for a one-year period beginning with the effective date of the new rates.

With respect to excess deferred income taxes (EDIT) resulting from reductions in the corporate federal and state income tax rates, the Commission is requiring that: (a) Aqua NC's Protected Federal EDIT shall be flowed back to customers following the tax normalization rules utilizing the average rate assumption method (ARAM) as required by the rules of the Internal Revenue Service; (b) Aqua NC's Unprotected Federal EDIT shall be returned to ratepayers through a levelized rider over a period of three years; and (c) Aqua NC's State EDIT shall be returned to customers through a levelized rider that will expire at the end of a three-year period.

Aqua NC will provide the applicable dollar amounts concerning (1) the one-year surcharge credit and (2) the federal and state EDIT riders (refunds) shown as separate line items on individual customers' monthly bills, along with explanatory information.

ISSUED BY ORDER OF THE COMMISSION.
This the 18th day of December, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

WATER AND SEWER – RATE INCREASE

CERTIFICATE OF SERVICE

I, ______________________________, mailed with sufficient postage or hand delivered to all affected customers the attached Notices to Customers issued by the North Carolina Utilities Commission in Docket No. W-218, Sub 497, and the Notices were mailed or hand delivered by the date specified in the Order.

This the ___ day of ________________, 20___.

By: ____________________________
Signature

____
Name of Utility Company

The above named Applicant, ______________________________, personally appeared before me this day and, being first duly sworn, says that the required Notices to Customers were mailed or hand delivered to all affected customers, as required by the Commission Order dated ____________________ in Docket No. W-218, Sub 497.

Witness my hand and notarial seal, this the ____ day of _______________, 20____.

____
Notary Public

____
Printed or Typed Name

(SEAL) My Commission Expires: ________________________________
Date

DOCKET NO. W-218, SUB 497

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Aqua North Carolina, Inc., 202 MacKenan Court, Cary, North Carolina 27511, for Authority to Adjust and Increase Rates for Water and Sewer Utility Service in All Service Areas in North Carolina	)))))	ORDER CLARIFYING CALCULATION OF REFUND OF STATE AND UNPROTECTED FEDERAL EXCESS DEFERRED INCOME TAXES

BY THE COMMISSION: On December 18, 2018, the Commission issued an Order Approving Partial Settlement Agreement and Stipulation, Granting Partial Rate Increase, and Requiring Customer Notice (Order) in the above-captioned docket, a general rate case proceeding for Aqua North Carolina, Inc. (Aqua NC or Company). With regard to Aqua NC's unprotected federal excess deferred income taxes (EDIT) and state EDIT addressed in this general rate case proceeding, on Pages 135-136 of its Order, the Commission concluded that it was appropriate to accept and approve the Partial Settlement Agreement and Stipulation (Stipulation) by Aqua NC and the Public Staff filed on September 17, 2018. The following language was included in the Commission's Order:

. . .

3. The Company's unprotected federal EDIT shall be returned to ratepayers through a levelized rider over a period of three years.

. . .

5. The Company's state EDIT recorded pursuant to the Commission's Order Addressing the Impacts of HB 998 on North Carolina Public Utilities issued May 13, 2014, in Docket No. M-100, Sub 138 shall be returned to ratepayers through a levelized rider that will expire at the end of a three-year period.

After the Order was issued, Aqua NC sought informal clarification of the term "levelized rider" as it was used by the Commission. Specifically, Aqua NC communicated by email to the Commission and all parties that it sought clarification of whether "levelized rider" meant monthly refunds over the three-year period based on a flat (equal) per customer rate or monthly refunds over the three-year period based upon a calculation utilizing the customer's total service bill (base and commodity charges). Aqua NC stated its interpretation of such wording is that a flat per customer rate over the three-year period would be appropriate.

The Attorney General's Office (AGO) argued that the return of the EDIT using a flat per customer rate would more fairly spread the effects of the rider to reduce the customer's monthly base charge than a method based upon the percentage of the customer's total service bill. Further, the AGO expressed the view that lower fixed monthly charges tend to be less burdensome for low income and elderly consumers.

The Public Staff – North Carolina Utilities Commission (Public Staff) responded that basing the amount returned on customers' total service bills is the most fair and equitable method of returning the EDIT because it most nearly approximates the manner in which the EDIT was collected from customers. The more a customer paid in service charges, the more he or she contributed to EDIT collected by Aqua NC, and the amount contributed should be reflected in the amount returned. The Public Staff commented that a rider based on total service bills, as the Public Staff recommends, would be calculated as a percentage for each rate entity in a manner similar to that used to calculate the Company's water system improvement charge (WSIC) and sewer system improvement charge (SSIC) surcharges.

Regarding Aqua NC's request for clarification of the meaning of "levelized rider" with respect to the refunds of the unprotected federal EDIT and state EDIT, in the December 18, 2018 Order, the Commission adopted such wording from Page 9, Section III, Paragraphs II. and JJ. of the Stipulation. In adopting the language agreed upon by the Public Staff and Aqua NC, the Commission accepted and intended the term "levelized rider" to mean the total dollar amount of the refunds of EDIT, including carrying costs calculated utilizing an annuity factor based upon the capital structure and cost rates for debt and common equity (net of tax) approved in the Commission's Order, divided equally over a three-year period—not to mean a flat per customer monthly refund amount. The Commission hereby clarifies its Order concerning the refunds to customers of the unprotected federal EDIT and the state EDIT accordingly.

Further, the Commission agrees with the Public Staff that basing the amounts to be refunded on customers' total service bills rather than on a flat per customer rate is the fairer and more equitable method of returning the EDIT because it most nearly approximates the manner in which the EDIT was collected from customers. Consequently, the Commission finds and concludes that the total dollar amount of the EDIT refunds shall be equally divided over a three-year period and the monthly refunds to customers over the three-year period shall be calculated based upon each customer's total service bill, which includes base and commodity charges.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 28th day of December, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. W-218, SUB 497

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Aqua North Carolina, Inc.,	)	
202 MacKenan Court, Cary, North Carolina 27511,	)	
for Authority to Adjust and Increase Rates for	)	ERRATA ORDER
Water and Sewer Utility Service in All Service	)	
Areas in North Carolina	)	

BY THE PRESIDING COMMISSIONER: On December 18, 2018, the Commission issued an Order Approving Partial Settlement Agreement and Stipulation, Granting Partial Rate Increase, and Requiring Customer Notice in the above-captioned docket. It has come to the attention of the Commission that Appendix B-1 contains an inadvertent error with respect to the average bill under prior rates for sewer utility service stated on Page 6 of 7. The average bill under prior rates was stated as $65.57 rather than $67.57.

The Presiding Commissioner finds good cause to order the correction of the error in Appendix B-1.

IT IS, THEREFORE, ORDERED as follows:

1. That the amended Appendix B-1, attached hereto, shall be substituted for the Appendix B-1 attached to the Order issued on December 18, 2018, in this docket.

2. That except as amended herein, the Order issued on December 18, 2018, shall remain in full force and effect.

3. That the Notice to Customers, attached as Appendix B-1, shall be mailed with sufficient postage or hand delivered by Aqua North Carolina, Inc. (Aqua NC) to all affected customers in conjunction with the next regularly scheduled billing process; and that Aqua NC shall submit to the Commission the attached Certificate of Service properly signed and notarized no later than 35 days after the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 28th day of December, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

APPENDIX B-1
PAGE 1 OF 7

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-218, SUB 497

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Aqua North Carolina, Inc.,	)	
202 MacKenan Court, Cary, North Carolina	)	NOTICE TO CUSTOMERS
27511, for Authority to Increase Rates for	)	IN AQUA NORTH CAROLINA
Water and Sewer Utility Service in All of Its	)	SERVICE AREAS
Service Areas in North Carolina	)	

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing Aqua North Carolina, Inc. (Aqua NC), to increase its rates for water and sewer service in its service areas in North Carolina. The new approved water and sewer rates for Aqua NC customers, excluding the Brookwood / LaGrange service areas in Cumberland and Hoke Counties and the Fairways / Beau Rivage service areas in New Hanover County, are as follows:

WATER UTILITY SERVICE

Monthly Metered Service (Residential and Commercial customers)

Base charge (zero usage, based on meter size)

<1" meter	$ 19.25
1" meter	$ 48.13
1-1/2" meter	$ 96.25
2" meter	$154.00
3" meter	$288.75
4" meter	$481.25
6" meter	$962.50

Usage charge, per 1,000 gallons $ 5.83

WATER AND SEWER – RATE INCREASE

Bulk Purchased Water Systems
Base monthly charge same as above

Usage charge per 1,000 gallons, where water purchased for resale as shown below:

Service Area	Water Provider	Usage Charge
Twin Creeks	City of Asheville	$ 4.26
Heather Glen and Highland	City of Belmont	$14.40
Southpoint Landing	City of Belmont	$14.40
Park South	City of Charlotte	$ 1.81
Parkway Crossing	City of Charlotte	$ 1.81
Springhill / Springdale	City of Concord	$ 5.11
Hoopers Valley	City of Hendersonville	$ 3.06
Crystal Creek	City of Hendersonville	$ 3.06
Rambling Ridge	City of Hendersonville	$ 3.06
Brookwood	City of Hickory (outside city)	$ 5.04
Heritage Farms	City of Hickory (inside city)	$ 2.83
Cedarwood Estates	City of Hickory (inside city)	$ 2.83
Hill-N-Dale	City of Lincolnton	$ 7.70
East Shores	City of Morganton	$ 2.52
Greenfield	City of Mount Airy	$ 7.15
Bett's Brook	City of Newton	$ 2.85
Crestwood	Davidson Water, Inc.	$ 5.30
Lancer Acres	Davidson Water, Inc.	$ 5.30
Beard Acres	Davidson Water, Inc.	$ 5.30
Woodlake Development	Harnett County	$ 2.77
Beechwood Cove	Chatham County	$ 7.04
Chatham	Chatham County	$ 7.04
Cole Park Plaza Shopping Center	Chatham County	$10.01
Hidden Valley	Chatham County	$ 7.04
Polks Landing	Chatham County	$ 7.04
Chapel Ridge	Town of Pittsboro	$13.69
Laurel Ridge	Town of Pittsboro	$13.69
The Parks at Meadowview	Town of Pittsboro	$13.69
River Hill Heights	Iredell Water Corp.	$ 2.72

WATER AND SEWER – RATE INCREASE

APPENDIX B-1
PAGE 3 OF 7

Service Area	Water Provider	Usage Charge
Bedford at Flowers Plantation	Johnston County	$ 2.45
Bennett Place	Johnston County	$ 2.45
Chatham	Johnston County	$ 2.45
Cottages at Evergreen	Johnston County	$ 2.45
Cottonfield Village	Johnston County	$ 2.45
Creekside Place	Johnston County	$ 2.45
Eastlake at Flowers Plantation	Johnston County	$ 2.45
Evergreen	Johnston County	$ 2.45
Flowers Crest	Johnston County	$ 2.45
Flowers Shopping Center	Johnston County	$ 2.45
Forge Creek	Johnston County	$ 2.45
Longleaf	Johnston County	$ 2.45
Magnolia	Johnston County	$ 2.45
Magnolia Place/Village	Johnston County	$ 2.45
Mill Creek North	Johnston County	$ 2.45
Mill Creek West	Johnston County	$ 2.45
Neuse Colony	Johnston County	$ 2.45
North Farm	Johnston County	$ 2.45
North Farm Cottages	Johnston County	$ 2.45
North Village	Johnston County	$ 2.45
Parkway Center/Village	Johnston County	$ 2.45
Peachtree	Johnston County	$ 2.45
Pineville Club	Johnston County	$ 2.45
Pineville East	Johnston County	$ 2.45
Pineville East Cottages/Palmetto Pl.	Johnston County	$ 2.45
Pineville East Estates	Johnston County	$ 2.45
Pineville West	Johnston County	$ 2.45
Plantation Park	Johnston County	$ 2.45
Plantation Pointe	Johnston County	$ 2.45
Poplar Woods	Johnston County	$ 2.45
River Dell East	Johnston County	$ 2.45
River Dell Townes	Johnston County	$ 2.45
Riverdell Elementary School	Johnston County	$ 2.45
South Plantation	Johnston County	$ 2.45
South Quarter	Johnston County	$ 2.45
Southgate	Johnston County	$ 2.45
Summerset Place	Johnston County	$ 2.45
Sun Ridge Farms	Johnston County	$ 2.45
Sweetgrass	Johnston County	$ 2.45
The Gardens at Flowers Plantation	Johnston County	$ 2.45

APPENDIX B-1
PAGE 4 OF 7

Service Area	Water Provider	Usage Charge
The Meadows	Johnston County	$ 2.45
The Nine	Johnston County	$ 2.45
The Woodlands	Johnston County	$ 2.45
Trillium	Johnston County	$ 2.45
Village at Flowers Plantation	Johnston County	$ 2.45
Walker Woods	Johnston County	$ 2.45
Watson's Mill	Johnston County	$ 2.45
West Ashley	Johnston County	$ 2.45
Whitfield at Flowers Plantation	Johnston County	$ 2.45
Wilders Woods and Extension	Johnston County	$ 2.45
Holly Hills	Town of Forest City	$ 5.95
Pear Meadows	Town of Fuquay-Varina	$ 4.35
Swiss Pine Lake	Town of Spruce Pine	$ 4.93

Monthly Unmetered service (flat rate)

Residential customers	$ 39.66
Commercial customers (per *REU)	$ 67.42

*(REU = Residential Equivalent Unit)

APPENDIX B-1
PAGE 5 OF 7

SEWER UTILITY SERVICE

Monthly Unmetered Service (flat rate)
All service areas unless noted differently below

Residential customers	$ 72.04
Commercial customers (per *REU)	$ 100.86

*(REU = Residential Equivalent Unit)

STEP system flat rate (Monticello, Holly Brook, Saddleridge)	$ 32.00

Commercial Monthly Metered Service and all the Park South Station and Parkway Crossing Service Areas (based on metered water usage)

WATER AND SEWER – RATE INCREASE

Base facility charge (zero usage, based on water meter size)	
All service areas unless noted differently below	
<1" meter	$ 26.11
1" meter	$ 65.28
1½" meter	$ 130.55
2" meter	$ 208.88
3" meter	$ 391.65
4" meter	$ 652.75
6" meter	$1,305.50
Usage charge, per 1,000 gallons	$ 8.92
All service areas unless noted differently below	
Park South Station and Parkway Crossing Service Areas	
Base facility charge:	As shown above
Usage charge/1,000 gallons	$ 6.45
Hawthorne Green (formerly Vista Park Apartments)	
Base facility charge/REU	$ 40.40
Usage charge, per 1,000 gallons	$ 6.11

IMPACT ON AVERAGE RESIDENTIAL BILL

The impact on the average monthly residential bill including the reset of the water and sewer system improvement charge (WSIC and SSIC) is as follows:

	Water	Sewer
Average bill under prior rates	$47.05	$67.57
Average bill under approved rates	$48.23	$72.04

The average monthly residential bills are based on the uniform rates for non-purchased water and sewer systems based on an average usage of 4,971 gallons per month. The average residential bills for the bulk purchased water and sewer systems will vary.

RATE ADJUSTMENT MECHANISM:

The Commission-authorized WSIC and SSIC rate adjustment mechanisms continue in effect. These charges have been reset to zero in the Docket No. W-218, Sub 497 rate case, but Aqua NC may, under the Rules and Regulations of the Commission, apply for a rate surcharge on May 1, 2019, to become effective July 1, 2019. The WSIC/SSIC mechanisms are designed to recover, between rate case proceedings, the costs associated with investment in certain completed, eligible projects for water and sewer system improvements. The WSIC/SSIC mechanisms are subject to Commission approval and to audit and refund provisions. Any cumulative system improvement charge recovered pursuant to the WSIC/SSIC mechanisms may not exceed 5% of the total annual service revenues approved by the Commission in this general rate case proceeding. Additional information regarding the WSIC/SSIC mechanisms is contained in the Commission's Order and can be accessed from the Commission's website at www.ncuc.net, under Docket Information, using the Docket Search feature for docket number "W-218 Sub 497" or W-218 Sub 497A".

CREDIT/REFUNDS DUE TO REDUCTIONS IN CORPORATE FEDERAL AND STATE INCOME TAX RATES:

On December 22, 2017, President Donald J. Trump signed into law the Tax Cuts and Jobs Act (The Tax Act), which among other things, reduced the federal corporate income tax rate from 35% to 21%, effective for taxable years beginning after December 31, 2017. In the present rate case proceeding, the Commission reduced Aqua NC's revenue requirement to reflect the reduction in the federal corporate income tax rate from 35% to 21%, on the Company's ongoing federal income tax expense. Further, the Commission is requiring that Aqua NC refund to its customers the overcollection of federal income

taxes related to the decrease in the federal corporate income tax rate for the period beginning January 1, 2018, and corresponding interest, through a surcharge credit for a one-year period beginning with the effective date of the new rates.

With respect to excess deferred income taxes (EDIT) resulting from reductions in the corporate federal and state income tax rates, the Commission is requiring that: (a) Aqua NC's Protected Federal EDIT shall be flowed back to customers following the tax normalization rules utilizing the average rate assumption method (ARAM) as required by the rules of the Internal Revenue Service; (b) Aqua NC's Unprotected Federal EDIT shall be returned to ratepayers through a levelized rider over a period of three years; and (c) Aqua NC's State EDIT shall be returned to customers through a levelized rider that will expire at the end of a three-year period.

WATER AND SEWER – RATE INCREASE

Aqua NC will provide the applicable dollar amounts concerning (1) the one-year surcharge credit and (2) the federal and state EDIT riders (refunds) shown as separate line items on individual customers' monthly bills, along with explanatory information.

ISSUED BY ORDER OF THE COMMISSION.
This the 28th day of December, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

CERTIFICATE OF SERVICE

I, ______________________________, mailed with sufficient postage or hand delivered to all affected customers the attached Notice to Customers issued by the North Carolina Utilities Commission in Docket No. W-218, Sub 497, and the Notice was mailed or hand delivered by the date specified in the Order.

This the ___ day of ________________, 20___.

By: ____________________________
Signature

____
Name of Utility Company

The above named Applicant, ______________________________, personally appeared before me this day and, being first duly sworn, says that the required Notice to Customers was mailed or hand delivered to all affected customers, as required by the Commission Order dated ____________________ in Docket No. W-218, Sub 497.

Witness my hand and notarial seal, this the ____ day of _____________, 20____.

____
Notary Public

____
Printed or Typed Name

(SEAL) My Commission Expires: ____________________________
Date

DOCKET NO. W-1075, SUB 12

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by KRJ, Inc., d/b/a KRJ Utilities, Post Office Box 2369, Swansboro, North Carolina 28584, for Authority to Increase Rates for Water and Sewer Utility Service in Its Southern Trace and Rockbridge Subdivisions in Wake County, North Carolina	))))))	ORDER APPROVING STIPULATION WITH A CONDITION, GRANTING PARTIAL RATE INCREASE, AND REQUIRING CUSTOMER NOTICE

HEARD: Tuesday, May 15, 2018, at 7:00 p.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

Wednesday, June 20, 2018, at 9:30 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Charlotte A. Mitchell, Presiding, Chairman Edward S. Finley, Jr., and Commissioner James G. Patterson

APPEARANCES:

For KRJ Inc., d/b/a KRJ Utilities:

Robert H. Bennink, Jr., Bennink Law Office, 130 Murphy Drive, Cary, North Carolina 27513

For the Using and Consuming Public:

Gina C. Holt and William E. Grantmyre, Staff Attorneys, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

BY THE COMMISSION: On December 4, 2017, KRJ, Inc., d/b/a KRJ Utilities (KRJ or Company) filed a letter notifying the North Carolina Utilities Commission (Commission or NCUC) of its intent to file a general rate case as required by Commission Rule R1-17(a).

On January 10, 2018, KRJ filed an application with the Commission seeking authority to increase its rates and charges for water utility service in Southern Trace Subdivision and for water and sewer utility service in Rockbridge Subdivision, both in Wake County, North Carolina.

By letter dated and filed on January 25, 2018, the Public Staff – North Carolina Utilities Commission (Public Staff) informed the Company that, pursuant to Commission Rule R1-17(f)(1), certain additional information needed to be filed to complete the Company's rate increase application.

On January 30, 2018, the Company filed its response to the Public Staff's January 25, 2018 letter, which provided the identified additional information in compliance with the provisions of Commission Rule R1-17(b).

By Order dated February 6, 2018, the Commission declared this docket to be a general rate case, suspended the Company's proposed rates, scheduled public and evidentiary hearings, and required customer notice. The Commission's Order specified that KRJ's direct testimony should be filed on or before May 8, 2018; that the Public Staff and intervenors should prefile testimony on or before May 21, 2018; and that KRJ should prefile any rebuttal testimony no later than June 4, 2018.

The intervention and participation by the Public Staff was made and recognized pursuant to N.C. Gen. Stat. § 62-15(d) and Rule R1-19(e) of the Rules and Regulations of the Commission.

KRJ filed the Commission-required Certificate of Service on February 20, 2018, indicating that the Company provided the Notice to Customers in compliance with the February 6, 2018 Order.

On May 4, 2018, KRJ filed the direct testimony and exhibits of its witness, James R. Butler, P.E.

On May 18, 2018, the Public Staff filed a motion for extension of time to file testimony until May 25, 2018, which was granted by Commission Order issued on that same date.

On May 24, 2018, the Public Staff filed a second motion for extension of time to file testimony until May 31, 2018, which was granted by Commission Order issued on May 25, 2018.

On May 30, 2018, the Company filed a Report on Customer Comments from Public Hearing held in Raleigh, North Carolina on May 15, 2018.

On May 31, 2018, the Public Staff filed a third motion for extension of time to file testimony until June 7, 2018, which was granted by Commission Order issued on June 1, 2018.

Subsequent to the filing of the Company's Application in this docket, the Public Staff engaged in substantial discovery of KRJ regarding the matters addressed by the Company's Application and further examined the relevant books and records of KRJ with respect to the Company's Application. The Public Staff's discovery efforts spanned a period of 19 weeks, entailed 10 sets of data requests directed to the Company and numerous informal follow-up questions. The Public Staff also conducted field inspections of the water system at Southern Trace Subdivision and the water and sewer system at Rockbridge Subdivision.

Following completion of the Public Staff's investigation of the Company's Application and accompanying documents, review of the results of its examination of the Company's books and records, and review of the Company's responses to the Public Staff's data requests, the Stipulating Parties corresponded and participated in meetings and conference calls over the course of several business days to discuss possible settlement.

WATER AND SEWER – RATE INCREASE

After significant negotiations, the Stipulating Parties were ultimately able to arrive at a settlement of all issues in this case. The Stipulation reflects the stipulated rate of return on rate base and operating margin and the Company's revenue requirements. The Stipulation and the new water and sewer rates set forth therein reflect an increase of 16.1% in KRJ's combined water and sewer revenues when compared to the Company's total operating revenues under present rates.

On June 7, 2018, the Public Staff prefiled the testimony and exhibits of Public Staff witnesses Iris Morgan, Staff Accountant, Water Section, Accounting Division; and Gina Y. Casselberry, Utilities Engineer, Water, Sewer, and Telecommunications Division; and the affidavit of John R. Hinton, Director, Economic Research Division.

On June 7, 2018, the Public Staff also filed a Stipulation entered into by KRJ and the Public Staff (Stipulating Parties). In the Stipulation, the Stipulating Parties agreed that the levels of rate base, revenues, and expenses set forth in Morgan Exhibit I and Morgan Exhibit II, which were incorporated by reference therein, are the appropriate levels for use in this proceeding.

On June 8, 2018, the Public Staff filed the corrected testimony and exhibits of Iris Morgan.

Eleven different witnesses testified at the public hearing in Raleigh on May 15, 2018. Three of those witnesses, who reside in KRJ's Southern Trace service area and are water utility customers, were Thomas D. Rains, Jacqueline Walker, and Shelley Iverson. The remaining eight witnesses, who reside in the Company's Rockbridge service area and are water and sewer utility customers, were Craig. E. Buzak, Pat Foran, Robert C. Herbert, Jr., Taunia Teel, Brian Maxwell, Gerald Daniel, Kathleen Kendzierski, and Ginger Rodgers.

On Wednesday, June 20, 2018, the evidentiary hearing was convened in Raleigh, North Carolina as scheduled. Five customers testified at the evidentiary hearing. our of those witnesses, who reside in KRJ's Southern Trace service area and are water utility customers, were Shelley Iverson, Jacqueline Walker, Gregory Cols, and Gabriel Hoxie. Witnesses Iverson and Walker, who previously testified at the public hearing, offered additional testimony. The fifth customer witness was Veronica Long, who resides in the Company's Rockbridge service area and is a water and sewer utility customer.

The prefiled testimony presented by KRJ witness Butler and Public Staff witnesses Morgan and Casselberry, and the Hinton affidavit, were copied into the record as if given orally from the witness stand. The following documents were admitted in evidence: the exhibits to the testimony of KRJ witness Butler; KRJ's Application, including attached exhibits; KRJ's additional information filed on January 30, 2018; the report filed by KRJ related to customer testimony at the public hearing held on May 15, 2018; the Stipulation; and the exhibits to the testimony of Public Staff witnesses Morgan and Casselberry.

On July 10, 2018, the Public Staff filed certain late-filed exhibits as requested by the Commission during the evidentiary hearing. These exhibits were prepared by Public Staff witnesses Morgan and Casselberry.

On July 10, 2018, KRJ filed the Verified Affidavit and Late-Filed Exhibit of James R. Butler.

On July 11, 2018, KRJ and the Public Staff filed a Joint Proposed Order.

On the basis of the Application; the Stipulation; the testimony of the public witnesses; the testimony and exhibits of KRJ witness Butler; the testimony and exhibits of Public Staff witnesses Morgan and Casselberry; the affidavit of John R. Hinton; and the entire record in this proceeding, the Commission is of the opinion that the provisions of the Stipulation are just and reasonable. Accordingly, the Commission now makes the following

FINDINGS OF FACT

1. KRJ is a corporation duly organized under the law and is authorized to do business as a regulated investor-owned water and sewer public utility in the State of North Carolina. The Company is subject to the regulatory oversight of this Commission. KRJ provides water utility service to customers in the Southern Trace Subdivision and water and sewer utility service to customers in the Rockbridge Subdivision.

2. KRJ is properly before the Commission pursuant to Chapter 62 of the General Statutes of North Carolina seeking a determination of the justness and reasonableness of its proposed rates and charges for its water and sewer utility operations.

3. As of March 31, 2018, KRJ served 190 water customers at Southern Trace Subdivision and 324 water and sewer customers and three water-only customers at Rockbridge Subdivision.

4. A total of 14 different customers testified at the public hearing and the evidentiary hearing (including two customers who testified at both hearings),[1] with many of those witnesses expressing service-related concerns. Those concerns generally included level of service (including repairs), water quality, communications, and other concerns. In addition, most, if not all, of the customers who appeared as witnesses testified in opposition to the proposed rate increase.

5. KRJ filed a report with the Commission, verified by Company witness James R. Butler, addressing the service-related concerns and other comments expressed by the 11 customers who testified at the public hearing. Such report described each of the witnesses' specific service-related concerns and comments, the Company's response, and how each concern and comment was addressed, if applicable. KRJ witness Butler, during his testimony at the evidentiary hearing, responded to and addressed in detail the service-related concerns and comments offered by the five customers who testified at that hearing.

6. The overall quality of service provided by KRJ is adequate.

[1] Eleven customer testified at the public hearing and five customers testified at the evidentiary hearing.

WATER AND SEWER – RATE INCREASE

7. The test period for this rate case proceeding is the 12-month period ended June 30, 2016, updated to March 31, 2018, and adjusted for certain known, actual, and measurable changes in plant, revenues, and costs based upon circumstances and events occurring or becoming known through May 31, 2018, prior to the close of the evidentiary hearing in this proceeding.

8. The Company's present rates have been in effect since they were approved by the Commission for the Southern Trace Subdivision in a general rate case Order dated January 14, 2005, in Docket No. W-1075, Sub 4, and for the Rockbridge Subdivision in the Order Granting Certificate of Public Convenience and Necessity and Approving Rates dated November 30, 2006, in Docket No. W-1075, Sub 5. The approved rates for both Southern Trace and Rockbridge Subdivisions were subsequently reduced by the Commission for the repeal of the gross receipts tax and State corporate income tax rate reductions.

9. On Junes 7, 2018, KRJ and the Public Staff filed a Stipulation which settled all issues between the Company and the Public Staff. The Public Staff filed a Corrected Stipulation Page 8 on June 14, 2018. The Stipulation reflects an agreed-upon increase of approximately 16.1% in KRJ's combined water and sewer revenues above the Company's total operating revenues under present rates.

10. The levels of rate base, revenues, and expenses set forth in Morgan Exhibit I and Morgan Exhibit II, attached to the corrected testimony of Public Staff witness Morgan filed on June 8, 2018, which are incorporated by reference herein, are the reasonable and appropriate levels for use in this proceeding.

11. The original cost rate base used and useful in providing service to the Company's customers is $83,398 for Southern Trace water operations, $448,926 for Rockbridge water operations, and $336,054 for Rockbridge sewer operations. The stipulated revenue requirements result in a 43.3% increase in total water revenues for Southern Trace water operations compared to the applied for 81.8% increase; a 90.4% increase in total water revenues for Rockbridge water operations, compared to the applied for 136.3% increase; and a 14.3% decrease in total sewer revenues for Rockbridge sewer operations compared to the applied for 52.4% increase.

12. The levels of total operating revenues under present rates appropriate for use in this proceeding are $74,797 for Southern Trace water operations; $85,093 for Rockbridge water operations; and $274,950 for Rockbridge sewer operations, for a total level of operating revenues for combined operations of $434,840 as follows:

	Service Revenues Under Present Rates	Misc. Revenues & Uncollectibles Present Rates	Total Operating Revenues Under Present Rates
Southern Trace Water	$74,606	$191	$ 74,797
Rockbridge Water	$82,944	$2,149	$ 85,093
Rockbridge Sewer	$265,667	$9,283	$274,950
Total	$423,217	$11,623	$434,840

WATER AND SEWER – RATE INCREASE

13. The overall levels of operating revenue deductions, including depreciation, regulatory fees, and taxes, under the present rates which are reasonable and appropriate for use in this proceeding are $97,299 for Southern Trace water operations, $120,634 for Rockbridge water operations, and $218,897 for Rockbridge sewer operations.

14. The reasonable level of plant in service for use in this proceeding consists of the following balances for water and sewer operations:

Southern Trace Water Operations	$389,501
Rockbridge Water Operations	$1,472,674
Rockbridge Sewer Operations	$5,305,677

15. Accumulated depreciation consists of the following balances for water and sewer operations:

Southern Trace Water Operations	$ 257,622
Rockbridge Water Operations	$ 462,569
Rockbridge Sewer Operations	$1,450,273

16. Contributions in aid of construction (CIAC), reduced by accumulated amortization of CIAC, consist of the following amounts for water and sewer operations:

Southern Trace Water Operations	$ 59,327
Rockbridge Water Operations	$ 574,071
Rockbridge Sewer Operations	$3,541,012

17. The overall levels of total operating expenses under present rates appropriate for use in this proceeding are $88,089 for Southern Trace water operations; $103,128 for Rockbridge water operations; and $173,305 for Rockbridge sewer operations, for a total level of operating expenses under present rates for combined operations of$364,522.

18. It is reasonable and appropriate for KRJ to recover total rate case costs of $66,759, related to the current proceeding, to be amortized and collected over a three-year period, for an annual level of rate case expense of $5,027 for Southern Trace water, $8,653 for Rockbridge water, and $8,573 for Rockbridge sewer The total rate case costs in the amount of $66,759 include the cost of the application filing fee of $250, legal fees of $26,793, administrative fees of $37,988, and office supplies and overhead of $1,728.

19. The affidavit of Public Staff witness Hinton supports and justifies approval of an overall rate of return on rate base and an operating margin of 7.75% for KRJ in this rate case. The return of 7.75% was agreed to by the Company and the Public Staff in the Stipulation. The stipulated return of 7.75% is just, reasonable, and appropriate for use in setting rates in this proceeding. This stipulated rate of return will provide the Company with a reasonable opportunity, by sound management, to produce a fair return for its shareholders, considering changing economic conditions and other factors, to maintain its facilities and services in accordance with

the reasonable requirements of its customers in the territory covered by its franchises, and to compete in the market for capital funds on terms that are fair to its customers and to its existing investors. The stipulated overall rate of return, together with the Company's supported levels of rate base and operating expenses, result in a revenue requirement that is just and reasonable to the Company's customers in light of changing economic conditions.

20. It is reasonable and appropriate to determine the revenue requirement for KRJ for Rockbridge water and sewer rates using the rate base method as allowed by N.C. Gen. Stat. § 62-133 and the operating ratio methodology for Southern Trace water rates as allowed by N.C. Gen. Stat. § 62-133.1.

21. The overall rate of return that the Company should be allowed an opportunity to earn on its rate base in Rockbridge Subdivision is 7.75%.

22. The Company should be allowed a 7.75% margin on operating revenue deductions requiring a return for the Southern Trace Subdivision, which results in an operating ratio of 92.97% (including taxes) or 92.81% (excluding taxes). KRJ's reasonable and appropriate operating revenue reductions requiring a return in this case are $97,194, which produces a net operating income for return of $7,533.

23. It is reasonable and appropriate to use the current statutory regulatory fee rate of 0.14% to calculate KRJ's revenue requirement.

24. It is reasonable and appropriate to use the current State corporate income tax rate of 3% and the federal income tax rate of 21% to calculate KRJ's revenue requirement.

25. The agreed-upon stipulated rates will provide KRJ with a net increase in its annual level of authorized service revenues through rates and charges approved in this case by $70,105, a 16.1% increase, consisting of an increase for Southern Trace water operations of $32,377, an increase for Rockbridge water operations of $76,944, and a decrease for Rockbridge sewer operations of $39,216. After giving effect to these authorized increases in water revenues and a decrease in sewer revenues, the total annual operating revenues for the Company will be $504,945, consisting of the following levels of just and reasonable operating revenues:

	Service Revenues Under Stipulated Rates	Misc. Revenues & Uncollectibles Stipulated Rates	Total Operating Revenues Under Stipulated Rates
Southern Trace Water	$106,983	$191	$107,174
Rockbridge Water	$159,888	$2,149	$162,037
Rockbridge Sewer	$226,451	$9,283	$235,734
Total	$493,322	$11,623	$504,945

26. In the next general rate case filed by KRJ for the Company's Southern Trace and Rockbridge service areas, the stipulated amounts agreed to in this case, as approved herein by the Commission, for plant in service, accumulated depreciation, contributions in aid of construction

(CIAC), depreciation and amortization expense, and original cost rate base, shall be used as the starting point for the Company's rate case application and the Public Staff's investigation.

27. It is reasonable and appropriate for the Commission to authorize KRJ to increase its reconnection charge for Southern Trace Subdivision from $23.91 to $25.00, if water service is cut off by the Company for good cause; increase the reconnection charge for Southern Trace Subdivision from $19.12 to $20.00, if water service is disconnected at the customer's request; and increase the Southern Trace returned check charge from $23.96 to $25.00. For Rockbridge Subdivision, it is reasonable and appropriate to authorize KRJ to increase the Company's reconnection charge from $14.40 to $15.00 if water service is cut off for good cause or if water service is disconnected at the customer's request; and to increase the Company's returned check charge from $23.96 to $25.00. The Company's tariffs for Southern Trace and Rockbridge Subdivisions should continue to reflect a late charge of 1% per month to be applied to the unpaid balance of all bills still past due 25 days after the billing date. The Schedule of Rates (attached hereto as Appendices A-1 and A-2) for KRJ water and sewer utility service, agreed to by KRJ and the Public Staff, is just and reasonable and should be approved.

28. It is fair and reasonable to approve the stipulated provision which provides that no changes will be made to the Company's currently authorized tap fees. Therefore, KRJ's tap fees should continue to be reflected on the Company's approved rate schedule as follows:

Southern Trace:	
Water per Residential Equivalent Unit (REU)	$ 500.00
Rockbridge:	
Water per REU	$1,000.00
Sewer per REU	$8,000.00

29. It is fair and reasonable to approve the stipulated provision which provides that no changes will be made to the Company's originally-authorized availability fees for Rockbridge Subdivision. Therefore, the availability fees for Rockbridge Subdivision should continue to be reflected on the Company's approved rate schedule as follows:

Water – monthly availability rate per REU	$15.00
Sewer – monthly availability rate per REU	$70.00

30. The Stipulating Parties acknowledge that the Company is currently required, pursuant to Commission Order in Docket No. W-1075, Sub 5 (Sub 5 Order), and the Sub 5 Stipulation between the Public Staff and KRJ, which was incorporated by reference in the Order, to disclose the current Rockbridge water and sewer rates in marketing materials, with lot purchase agreements, and in the restrictive covenants pertaining to all lots in the Rockbridge Subdivision, to notify future customers in Rockbridge of the utility rates prior to their purchasing their lots or residences. As recommended by the Stipulating Parties, the Commission finds that this notice requirement is no longer necessary and that it should be rescinded, as the Rockbridge Subdivision is now at approximately 80% build-out and the Company's resources could be better placed elsewhere. Furthermore, the stipulated flat sewer rate of $58.25 for Rockbridge Subdivision is in line with the currently-approved flat sewer rates charged by other Commission-regulated public

utilities in North Carolina and the referenced notice requirement was unique to KRJ due to the facts and circumstances presented in Docket No. W-1075, Sub 5.

31. The Stipulating Parties acknowledge that, pursuant to Decretal Paragraph No. 5 of the Sub 5 Order, the Commission required KRJ to file annual reports, beginning on October 31, 2007, regarding the status of the Rockbridge Subdivision and utility system. KRJ was also required to continue to file these annual reports until 90% (367) of the homes in Rockbridge are receiving utility service. As recommended by the Stipulating Parties, the Commission finds that this annual report is no longer necessary and that it should be rescinded, as the Rockbridge Subdivision is now at approximately 80% build-out and the Company's resources could be better placed elsewhere. Furthermore, KRJ continues to be required to file a detailed annual report pursuant to N.C. Gen. Stat. § 62-36 and Commission Rule R1-32.

32. The following charts show the average monthly customer bills at the Company's present rates, including percentage increases and decreases, compared to the Commission-approved rates in this proceeding:

Southern Trace Subdivision

	Present Rates	Commission-Approved Rates
Monthly Metered Water Rates		
Base charge, zero usage	$19.12	$19.12
Usage charge, per 1,000 gallons	$ 2.66	$ 5.44
Average Bill	$32.73	$46.95
(Average usage 5,115 gallons)		
Percent Increase		43.45%

Rockbridge Subdivision

	Present Rates	Commission-Approved Rates
Monthly Metered Water Rates		
Base charge, zero usage	$14.40	$16.30
Usage charge, per 1,000 gallons	$ 1.49	$ 5.41
Average Bill	$21.13	$40.75
(Average usage 4,520 gallons)		
Percent Increase		92.85%
Monthly Flat Rate Sewer	$68.33	$58.25
Percent Decrease		(14.75%)
Combined Water and Sewer	$89.46	$99.00
Net Percent Increase		10.66%

33. The Stipulation contains the provision that the Stipulating Parties agree that, except for Paragraph 4.G. thereof (i.e., see Finding of Fact No. 26 above), none of the positions, treatments, figures, or other matters reflected in the agreement should have any precedential value,

nor should they otherwise be used in any subsequent proceedings before this Commission or any other regulatory body as proof of the matters in issue.

34. The Stipulation contains the provision that the agreements made therein do not bind the Stipulating Parties to the same positions in future proceedings, and the parties reserve the right to take different positions in any future proceedings. The Stipulation also contains the provision that no portion of the Stipulation is binding on the Stipulating Parties unless the entire Stipulation is accepted by the Commission.

DISCUSSION AND CONCLUSIONS

The evidence for the following conclusions is contained in the Application; the Stipulation; the testimony of the public witnesses; the testimony and exhibits of KRJ witness Butler, including his Verified Affidavit and Late-Filed Exhibit; the testimony and exhibits of Public Staff witnesses Morgan and Casselberry, including their Late-Filed Exhibits; the Public Staff Hinton affidavit; KRJ's Report on Customer Comments from Public Hearing in Raleigh, North Carolina, filed on May 30, 2018; and the entire record in this proceeding.

I. <u>Public and Evidentiary Hearings and Service Quality</u>

A public hearing was held in Raleigh on May 15, 2018, at 7:00 p.m., in Commission Hearing Room 2115 for the benefit of public or customer witnesses. Public witnesses were also given the opportunity to testify at the evidentiary hearing which was held in Raleigh on June 20, 2018, beginning at 9:30 a.m. Eleven different customers testified during the May 15, 2018 public hearing. Five customers, including two customers who also testified at the public hearing, testified at the evidentiary hearing. A total of 14 different customers testified at both hearings. Many customers expressed service-related concerns. Those concerns generally included level of service (including repairs), water quality, communications, and other concerns. In addition, most, if not all, of the customers who appeared as witnesses testified in opposition to the proposed rate increase.

In response to the customer comments, KRJ filed a report with the Commission on May 30, 2018, which was verified by KRJ witness James R. Butler, P.E., addressing the service-related and other concerns expressed by the customers who testified at the Raleigh public hearing. The report described each of the witnesses' specific service-related and other concerns, the Company's response, and how each concern was addressed, if applicable. A total of 11 witnesses testified at the Raleigh public hearing. Three of those witnesses reside in KRJ's Southern Trace service area and are water utility customers. The remaining eight witnesses reside in the Company's Rockbridge service area and are water and sewer utility customers. Customers variously raised issues about the level of service (including repairs), water quality, communications, and other concerns.

The Raleigh public hearing report is summarized and discussed below. In that report, KRJ initially set forth general comments applicable to both the Southern Trace and Rockbridge utility systems which are set forth, in pertinent part, as follows:

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A public hearing was held by the Commission in Raleigh on May 15, 2018, which was attended by representatives of the Public Staff and the Company. An evidentiary hearing will be held in Raleigh on June 20, 2018, to receive evidence and to examine the expert witnesses. Eleven customers testified, while numerous others attended the hearing but chose not to testify. Customers were given a full and fair opportunity to express their complaints and concerns. In addition, the Public Staff will conduct its own independent investigation to assess the quality of water and sewer utility service provided by KRJ to its customers at Southern Trace and Rockbridge.

The rate-setting process before the NCUC is rigorous and intensive, as it should be, and the burden of proof is on KRJ in this case to prove in a judicial arena that it merits additional rates. The public's assurance of fairness is found in the strict, highly-skilled oversight of the Public Staff and the Commission. Consumers can review every document that is filed and every NCUC Order that is issued on the Commission's website. The rate case procedures are open and fair. Rates charged by KRJ must be based on cost of service and must be justified by detailed proof which is carefully examined and may be challenged by the Public Staff in a contested legal proceeding. Rate increases, while controversial, are necessary to support prudent investment by public utilities, such as KRJ, in the capital-intensive water and sewer utility industry.

...KRJ is always willing to speak with customers regarding any questions they may have regarding billing, service, rates, etc. The Company takes very seriously its duty as a public utility in North Carolina to provide its customers with adequate, efficient, and reasonable service at reasonable rates as required by North Carolina law and the rules and regulations promulgated by the NCUC and NCDEQ.

...the water supplied by KRJ at Southern Trace and Rockbridge is potable and entirely safe to drink. It meets all State and Federal Safe Drinking Water Act requirements for potability and safety. KRJ concedes that customers may experience intermittent problems with the appearance of the water, such as cloudiness or a milky appearance, but those problems are generally transient and do not present health concerns. That said, by offering these comments, KRJ does not mean to minimize, in any way, customer testimony regarding their water quality concerns. To the contrary, the Company is fully committed to rectifying any problems, once reported, which are capable of correction as expeditiously as possible.

However, as a matter of full disclosure, some customers at Southern Trace recently experienced an episode of "muddy" brown water and air which was first reported to KRJ on the morning of Thursday, May 24, 2018. Company personnel were immediately dispatched to resolve the reported water quality problems and worked diligently for two days to do so. The situation is now stable. A copy of the May 28, 2018 Incident Report which KRJ sent to David Furr, who is the Director *of the Public Staff Water and Sewer Division, is attached to this report as Exhibit A. KRJ's Incident Report describes in detail the actions taken by the Company to address and resolve the situation.*

...the water pressure supplied by KRJ consistently meets or exceeds minimum State requirements and standards. As the case with any water system, pressure varies somewhat from time to time during the day due to the necessary expenditure and replenishment of water in the storage facilities that are a part of the water system.

...KRJ has implemented certain important and significant customer communication and service policy changes in response to the testimony offered by customers at the public hearing which are detailed later in this report.

Report Regarding Southern Trace Water System

The three witnesses served with water utility service by KRJ at Southern Trace were Thomas D. Rains, Jacqueline Walker, and Shelley Iverson. KRJ offered the following general responses to customer comments regarding the Southern Trace water system.

1. **Replacement of Submersible Pump at Well 2**

The replacement of the failed submersible pump located within well 2, which occurred during the period of time in July and August 2015, was complicated by failure of suppliers to provide proper replacement equipment. Much of the problems were as a result of the pump being powered by a 15-horsepower single phase submersible motor, which is quite difficult to find. Maintaining one as a spare is ill advised as there is a recognized "shelf" life of such a device which could render it unusable at a future date. At such time as the pump must again be replaced, KRJ will consider replacing it with the combination of a 3-phase pump powered by a modified variable frequency drive (VFD) to convert the only power available within Southern Trace (single phase) to 3-phase.

2. **Diminished Pumping Capacity of Well 2**

After replacement of the pump in well 2, it was determined in August 2015 that the yield of well 2 had diminished from its original 78 gallons per minute (gpm) to approximately 25 gpm. Fortunately, well 3 had been placed into service in June 2015 to augment production from wells 1 and 2. Upon identifying the decline in production of well 2, KRJ immediately set about locating a suitable contractor who could successfully renovate the well to recover as much of the lost capacity as possible. Such a contractor is not the typical well driller, but one who utilizes very specialized equipment and technique. The first such contractor provided a totally unresponsive proposal. KRJ's pursuit of a contractor continued through yet another, who declined to provide a quotation due to the scope of the project. KRJ is waiting on a proposal from a third prospective contractor.

At this time, the available well yield from all three wells serving Southern Trace is approximately 91 gpm; with the full capacity of well 2 restored, the well production capacity would be 144 gpm. Even with the reduced production from well 2, no low-pressure complaints were received by KRJ's office during 2017. However, the current situation does point out the limitation of the Southern Trace water system, and any small system, to support irrigation loads. A single in-ground irrigation spray head will discharge approximately 5 gpm. Were three irrigation systems each operating four spray heads at a time to be actuated simultaneously, the demand would consume two-thirds of the well production, leaving only 31 gpm, under current conditions, to accommodate domestic needs. KRJ has consistently attempted to educate its customers of the need to refrain from irrigation of lawns as small well-sourced water systems are not designed to accommodate other than domestic usage; such effort appears to have had some success.

3. **Electronic Pressure Control System**

Although the current system controlling the operation of the wells at Southern Trace is functioning well, KRJ intends to pursue a system that will utilize a control system that utilizes an electronic pressure transducer, which will produce more accurate pressure measurement than the pressure switches currently used; cellular data transmission, to avoid local interference with the radio communications system; and computer-based control logic. To date, equipment manufacturers have been identified, quotes obtained, and cellular field strength measurements made, to determine the most desirable cellular system to use. Scheduling of the installation will depend on availability of funds.

4. **Water Pressure Variations**

Pressure variations are both normal and necessary in any water system due to the necessary partial expenditure and replacement of water within the tank to assure that the water is turned over and does not lose its chlorine residual. When demand exceeds the pumping rate of the wells, pressure tanks (or elevated storage tanks) serve to provide water to the system when instantaneous demand rate exceeds instantaneous production rate. Water storage tanks serve as "shock absorbers" between demand and supply by contributing or receiving water from the distribution system. They may be either pressure tanks, as at Southern Trace, or an elevated storage tank, as at Rockbridge.

In its report, KRJ then discussed specific Southern Trace customer comments. With certain exceptions as discussed below (in particular, the extensive testimony of customer Thomas Rains. and certain other specific concerns expressed by a few customers), the summary of Southern Trace customer testimony included in the report and the Company's specific responses to those comments are incorporated herein by reference and will not be repeated in this Order, because they are adequately and fully addressed in the general comments set forth above.

WATER AND SEWER – RATE INCREASE

Response of KRJ to Testimony of Thomas Rains

First, KRJ wants to acknowledge appreciation for Mr. Rains' positive comments during his testimony to the effect that, in his opinion, during the last three years, customers have not experienced water pressure problems at Southern Trace to the extent they did in 2015, and that, in fairness to KRJ, the water system seems to be operating better today than it did in 2015. Next follows the Company's response to Mr. Rains' other less positive comments:

Test Year. As was stated by Public Staff Attorney William Grantmyre, the Public Staff will update the test year in this case for ratemaking purposes to the period April 1, 2017 - March 31, 2018, to be more reflective of current circumstances. KRJ has been fully cooperative with the Public Staff during its investigation and has supplied voluminous utility records during the discovery process.

Failure to Upgrade System. The service lives of various components of a water system vary widely from 10 years for mechanical items such as pumps to 50 years for buried mains and services. Normal water utility practice is to replace items as they indicate pending failure or in fact fail, unless upgrade is necessary to accommodate changes in system demand or water quality. Premature replacement of plant facilities serves only to unduly expedite the expenditure of capital funds and could needlessly exaggerate and expedite the necessity of more frequent, higher rate increases. The Southern Trace water system is less than 20 years old. Accepted service lives of principal system components are as follows: Storage tanks – 50 years; distribution mains - 50 years; wells - 50 years; well pumps - 7 years. With the exception of well pumps, failure due to age of the system is well into the future. KRJ stocks most routinely-needed repair parts, such as electric or electronic components and chemical feed equipment repair kits.

System Design. The entire water source, including the treatment and distribution system at Southern Trace, was designed, permitted and constructed consistent with the requirements of the NCDEQ, or that agency's predecessors. All water systems exhibit differing pressures at different locations due to their different elevations above sea level due to the effects of gravity; and Southern Trace is no exception. There is approximately 100 feet of elevation differential from the front (highest) to back (lowest) portions of the system, thereby resulting in a differential pressure at any given time of approximately 43 psi.

The system controls that cause the operation of the well pumps, the source of the pressure in the system, are set to cause the submersible pumps in the wells to run, pumping water into the system, at 70 psi, and cause the pumps to stop at 78 psi. The difference between system demand rate and pumping rate is accommodated by the two hydropneumatic tanks located proximate to well 1, which is also in the higher area of the subdivision. The result of this is that normal operation of the system causes pressures to be 70-80 psi at the higher areas and 110-120 psi in the lower areas. As a comparison, Raleigh's "497" system exhibits pressures ranging from 40 psi to 135 psi.

The issue at Southern Trace is not "pressure" but the "perception of pressure." As was stated, when customers located at the higher portions of the system observe reduced pressure, those at the lower ends of the system do not observe the same reduction. Stated differently, if the pressure at the higher portions of the system drop by 45 psi (from 80 to 35 psi) that change is very easily observed; whereas, if the same drop occurs at the lower portions of the system, which they will, the change in pressure from 120 to 75 psi will not be observed by affected customers, as all of the houses have code-required pressure reducing valves, which deliver a uniform pressure to the household plumbing, normally around 50 psi.

It should be noted that the required minimum pressure on a public water supply system is 30 psi. System pressure at Southern Trace is noted by the operator during each of his periodic rounds and system pressure is consistently observed to be in excess of 30 psi. KRJ knows of no way, other than continuous education of the customers, to address the issue; and clearly not by a physical system that would introduce not only additional complexity in the system but additional opportunities for mechanical failure.

"Remote" Management of the System / Lack of On-Site Engineering. The portion of the management that exists out of the Wake County area is that of customer support, accounting, and billing. KRJ's management contractor, Management Group[1] of NC, Inc. (MGNC), has trained personnel in the Wake County area to cause meter readings, customer collections, and, as necessary, triage system issues. Mr. Butler, the Vice President of MGNC, to whom Mr. Rains referred several times during his testimony, does live some distance from Wake County, but often returns to perform periodic observations of the systems of KRJ and provide technical support to other contract personnel, such as plant operators. He is both a licensed Professional Engineer and holds Treatment Operator Certifications well in excess of those required to operate the Southern Trace water system.

During the period of system duress in the spring/summer of 2015, Mr. Butler was on site in Southern Trace on three separate occasions to gain knowledge of exactly what was happening. The sequence of events during 2015 was: the submersible pump in well 2 failed; the particular model of pump was not available within the Continental United States, due to the manufacturer, and the large (15 horsepower) single-phase motor required due to the availability of electric power within Southern Trace; a new pump was ordered after the pump supplier advised KRJ's well contractor that it was a proper replacement based on his translation of the model number of the pump that failed; and the new pump was installed. This would have been the end of the issue, were it not for the fact that the supplier was incorrect in his translation of the model number which resulted in the new pump that been installed being incapable of performing. A proper replacement pump was obtained, and installed, only to find that its motor was defective. The pump had to be again removed from the well, a new motor affixed, and the pump had to again be reinstalled. Barring external damage, such as lightning, the pump should be functional for the remained of its anticipated service life of 7 years.

Overhaul of the Entire System. As stated previously, with the exception of the need for remediation work at well 2, the system is well within its useful life, and such an expense is not warranted.

Irrigation Demand. It is true that KRJ has opined on several occasions that increased demand for water imposed by irrigation systems may be exacerbating the water pressure/availability issues. Point of fact, it has been explained to Mr. Rains and many other customers that small water systems, such as the one serving Southern Trace, are not designed to accommodate irrigation demands, only domestic water usage. Unfortunately, a builder in the lower portion of the system offered in-ground irrigation systems to the prospective home purchasers, without the knowledge or consent of KRJ. Fortunately, recently, as was acknowledged by Mr. Rains, their use and potential for system stress has reduced.

KRJ's report also addressed the following additional specific comments from Southern Trace customers:

Cloudy Water. Intermittent cloudy water in systems with hydropneumatic tanks is not uncommon due to dissolution of air from within the tank into the water. As the water is tested consistent with the Safe Drinking Water Act and has been found compliant with the requirements of the Act, the cloudiness does not reflect any safety or health hazard.

Coloration of Water. As Public Staff attorney Grantmyre observed, the coloration of the water is most likely due to oxidized iron. Iron, although potentially imparting undesirable coloration, is not considered a health hazard, which is why it is on the United States Environmental Protection Agency's (USEPA) "Secondary" contaminant list as an aesthetic issue, rather than the "Primary" list which identifies health-risk contaminants. KRJ utilizes a process known as "sequestration" where a National Sanitation Foundation (NSF) approved chemical sequestering agent is added to the water containing free ion iron, which is colorless. The sequestering agent combines with the iron ion, as well as manganese, to prevent it from being oxidized by the chlorine added as a disinfectant, which would impart a color. Ideally, the distribution system would be flushed frequently to expel any settled sequestered iron. With the reduced yield of well 2, at present, flushing operations must be undertaken at less frequent intervals to conserve potable water.

Odor of Water. KRJ has no explanation for the odor that Ms. Iverson reports, as KRJ has not received odor complaints from the customers served by the Southern Trace system in many years.

Water Pressure. Ms. Iverson's residence is located in the "higher" portion of the subdivision, thus not enjoying the greater pressures present toward the lower areas.

The water pressure that KRJ maintains, except in periods where demand exceeds well output, is well above the 30-psi minimum and approaches in some cases the 80-psi maximum allowed by the plumbing code. Given the elevation above sea level of the residence, it is very possible that her residence is equipped with an unnecessary pressure reducing valve installed when the house was constructed. Mr. Butler contacted Mr. Iverson and provided information on re-setting the device to cause it to deliver the maximum pressure it will allow.

Report Regarding Rockbridge Water and Sewer Systems

The eight witnesses served with water and sewer utility service by KRJ at Rockbridge were Craig. E. Buzak, Pat Foran, Robert C. Herbert, Jr., Taunia Teel, Brian Maxwell, Gerald Daniel, Kathleen Kendzierski, and Ginger Rodgers. KRJ offered the following general responses to customer comments regarding the Rockbridge water and sewer systems.

1. **Water Leaks**

The water leaks spoken to by the customers providing testimony were, with one exception, as a result of service line leaks and not main breaks. The exception was when a main which had been marked was drilled into in 2017 by a contractor installing fiber-optic cable. The customers are correct in their observations that the vast majority of the service line leaks occurred on three specific streets within the 2006-2007 initial development phase of Rockbridge. What KRJ has determined is that the rock present in those areas fractures when being excavated during underground installations resulting in knife-like shards that if allowed to come in contact with the polyethylene tube service lines will over time cut the service, resulting in a water service leak. *Following the hearing, KRJ has established a new policy that if a given service line presents a leak for two occasions, it will be replaced rather than being repaired.*

2. **Repair Response Times and Improved Communications with Customers**

The customers offering testimony also observed their difficulty in obtaining information on repair of reported water leaks and that the leaks were not repaired in a timely fashion. *The day following the hearing, KRJ initiated a new protocol providing for improved communication between the plant operating personnel, maintenance/construction supervisor, contract manager, and utility contractor used to make repairs to assure that all Company personnel are kept abreast of the situations as they evolve so that customer inquiries can be answered with the best information possible and that the coordination of all utility personnel is significantly improved. The utility contractor was also counseled on the necessity that the response to reported problems should be as expeditious as possible and that the contractor was expected to provide timely completion of clean-up activities, including surface restoration, such as seeding or pavement repair. Mr. Butler will utilize his field technician in addition to the field maintenance/construction* *supervisor to triage the reported problems to better direct the repair contractor as to what materials and equipment they may require to address the problem. Additionally, to facilitate documentation and timely response to service issues, MGNC (through Mr. Butler) has established a new e-mail account -* ***info@mgnc.biz*** *- that is dedicated to receipt and response to customer reports of service issues and inquiries associated with other water/sewer utility matters.* That e-mail address will soon appear on monthly customer bill statements.

3. **Unwillingness of Certain Customers to Drink the Water Supplied by KRJ**

Several customers testified that they do not drink the water provided by KRJ and, instead, purchase bottled water. Although that may be their preference, or response to inaccurate information, they should be aware that KRJ's water system serving Rockbridge has had only one instance of a contaminant exceeding EPA's established levels. That instance was the identification of uranium, which is naturally occurring in some rock formations in the Wake County and some adjoining counties, and Gross Alpha which is most often associated with the presence of uranium in water. That situation never became such that the North Carolina Department of Environmental Quality Public Water Supply Section, USEPA's agent in enforcing the Federal Safe Drinking Water Act, declared a health emergency, requiring that alternate drinking water be provided.

The entire uranium issue was resolved by KRJ's installation of a uranium removal system which was placed into operation in June of 2016. No uranium has been detected in finished water samples since that time and the gross alpha has fallen to levels well below those acceptable under the Safe Drinking Water Act.

4. **Rate Case Test Year**

As was stated by Public Staff attorney Grantmyre, the Public Staff has updated the test year for ratemaking purposes in this case through the period April 1, 2017 - March 31, 2018, to be more reflective of current circumstances. KRJ has been fully cooperative with the Public Staff during its investigation and has supplied voluminous utility records during the discovery process.

5. **System Outages**

KRJ is aware of three system outages which occurred during the three-year period from 2015 through 2017: one associated with the damage caused by the fiber-optic installer, one where a control relay failed, and one caused by an error of the contractor installing the uranium removal system. To guard against significant pressure drops or equipment trips, a remote alarm system was installed at Rockbridge some time ago.

Although the current system controlling the operation of the wells at Rockbridge is functioning well, KRJ is pursuing a system that will utilize a control system that utilizes an electronic pressure transducer, which will produce more accurate pressure measurement than the pressure switches currently used; cellular data transmission, to avoid proximal interference; and computer-based control logic. To date, equipment manufacturers have been identified, quotes obtained, and cellular field strength measurements made, to determine the most desirable cellular system to use. Scheduling of the installation will depend on availability of funds.

6. **Water Pressure Variations**

Pressure variations are both normal and necessary in any water system due to the necessary partial expenditure and replacement of water within the tank to assure that the water is turned over and does not lose its chlorine residual and when demand exceeds pumping rate as the tank serves to provide water to the system when instantaneous demand rate exceeds instantaneous production rate. The water level in the Rockbridge elevated tank is designed to fluctuate between 115 feet to 144 feet above the base of the tank which translates to a normal pressure variation of 13 psi.

7. **Chlorine-Related Complaints**

Chlorine is required to be continuously applied, more recently by USEPA, to all public drinking water systems placed into operation since the mid-1970s. USEPA sets the maximum concentration of chlorine in drinking water to be 3.5 mg/L. Some people may exhibit higher sensitivity to chlorine than others and the Company sympathizes with those customers who offered testimony in that regard; for that reason, KRJ attempts to maintain the chlorine concentration as low as possible while complying with applicable regulations. The electronic control system for the application of chlorine and all other water treatment chemicals is such that they are applied in a flow proportional manner. Some variation in chlorine concentrations will always exist throughout a distribution system due to distance from the water plant and changes in flow patterns within the system. KRJ must maintain the chlorine concentration leaving the treatment facility at a level that assures at least a 0.1 mg/L concentration throughout the distribution system. Representative copies of recent operating reports which indicate actual chlorine residual measurements within the distribution system, as filed with the North Carolina Department of Environmental Quality, are attached to this report as Exhibit B.

In its report, KRJ then discussed specific Rockbridge customer comments. With certain exceptions as discussed below, the summary of Rockbridge customer testimony included in the report and the Company's specific responses to those comments are incorporated herein by reference and will not be repeated in this Order, because they are adequately and generally addressed in the general comments set forth above.

WATER AND SEWER – RATE INCREASE

Maintenance of Spray Fields. KRJ's ownership and the maintenance and construction supervisor have been consulted regarding the maintenance of the spray fields and they have committed to more frequent mowing and maintenance of those areas. To a large degree, the cost of mowing of the spray fields has to date been absorbed by the developer of Rockbridge; KRJ will be paying for mowing of the spray fields beginning this summer. In the specific case of the field to which Mr. Buzak referred, the slopes from the curb to the fields will be re seeded, as grass cover is sparse. The field itself has not yet been placed into service and is therefore not visited as often as those that are in service. The "geyser" referred to was a result of vandalism of both a control valve and a spray riser, both of which have been repaired.

Billing Practices. The Schedule of Rates ordered by the Commission for Rockbridge states: "Bills Past Due: 15 days after billing date." KRJ has always considered that the "billing date" was the date that the bills are mailed and applied to earned income and receivable ledger accounts. The "Date Mailed" that appears on the bill is the date that the bills are physically delivered to the United States Postal Service. Mr. Butler advises each new customer at the time that he is contacted by the customer to initiate their customer account that KRJ holds the "Past Due Date" uniform as the 5th day of each month and that the bills are mailed no less than 15 days prior to the "Past Due Date". The assertion that the bills are mailed after the "Due Date" is incorrect. A copy of a sample redacted utility bill is attached to this report as Exhibit C.

M&M Response. The statement from M&M reported by Mr. Daniel to the effect that that, recently, KRJ did not want to send a plumber out on a weekend to make a repair because "it was too expensive" was not, nor has it ever been, the position or attitude of KRJ regarding necessary repairs. KRJ sincerely apologizes to Mr. Daniel for the unauthorized and inappropriate comment. Newly-adopted protocols require that KRJ representatives triage reported leaks as soon as possible, and determine the most appropriate level of response, which includes "immediate" and "next working day" response times, depending on the severity of the issue.

Dress of Leak Repair Site. Subsequent to the hearing, Mr. Butler contacted the maintenance and construction supervisor and asked that personnel be sent to Mr. Daniel's residence to more appropriately dress the site of the service line repair. The supervisor revisited the site on May 23 and reports that the area has now been re-shaped and additional seed and mulch were added. Mr. Butler then attempted to contact Mr. Daniel to determine the customer's level of satisfaction with the site repair, but the cell phone number on file with KRJ was incorrect.

Milky Water. There are two potential causes for "milky water". The first is trapped air within water mains recently placed into service where the air becomes entrained in the water as microscopic bubbles. The second is insufficient alkalinity in the water which results in the water evolving carbon dioxide, the fizz in soda pop. KRJ augments alkalinity by the addition of lime slurry as part of the treatment process.

Minor variations in water quality from the wells may result in the lime slurry feed rate being insufficient, as KRJ attempts to minimize the application of lime to a concentration just above the effective level since alkalinity is observed by the customer as hardness. When KRJ receives such a complaint, it immediately determines whether the lime feed system is operating properly and, if appropriate, slow flushes the potentially offending water main in an attempt to purge it of any air-laden water.

Smell in the water. KRJ is unsure as to what smell Ms. Kendzierski is referring unless it is chlorine, which is spoken to in KRJ's general responses.

Uranium Issue. The issue regarding uranium and gross alpha exceedances is discussed in KRJ's general responses that precede the Company's customer-specific responses. At no time did the State of North Carolina or KRJ recommend or require acquisition of treatment systems by the customers; however, it is understood that some did so at their own choosing.

Raleigh Evidentiary Hearing (June 20, 2018)

The evidentiary hearing was convened in Raleigh, North Carolina as scheduled. Five customers testified at the evidentiary hearing. Four of those witnesses, who reside in KRJ's Southern Trace service area and are water utility customers, were Shelley Iverson, Jacqueline Walker, Gregory Cols, and Gaylord Hoxie. Witnesses Iverson and Walker, who previously testified at the public hearing, offered additional testimony. The fifth customer witness was Veronica Long, who resides in the Company's Rockbridge service area and is a water and sewer utility customer.

KRJ witness Butler, during his testimony at the evidentiary hearing, responded to and addressed in detail the service-related concerns and comments offered by the five customers who testified at the evidentiary hearing. He also expounded on and explained many of the observations and comments contained in the Company's written report, particularly as they applied to the customer testimony offered at the evidentiary hearing. Mr. Butler fully addressed and responded to the customer testimony from the evidentiary hearing which pertained to the late-May 2018 incident report attached to his prefiled testimony as Exhibit A.

Public Staff witness Casselberry testified that her investigation included review of customer complaints; contact with the Division of Water Resources (DWR), Public Water Supply Section (PWSS) and Water Quality (WQ); review of Company records and analysis of revenues at existing and proposed rates; and site inspection of the three KRJ utility systems. Witness Casselberry testified that she had contacted representatives of the Raleigh regional office regarding the operation of the KRJ water and sewer systems. She testified that none of the regional office personnel she contacted expressed any concerns with the water systems or the sewer system serving KRJ customers.

Witness Casselberry further testified that on May 15, 2018, she inspected the three KRJ systems with Mr. Rod Butler and other members of the Public Staff. The water systems in Southern Trace and Rockbridge were in good condition and adequately maintained. The new uranium removal system in Rockbridge was installed and operational. All of the chemical feed pumps used for treatment were operating and the containers were approximately 85 percent full. The WWTP in Rockbridge was in good condition. Witness Casselberry testified that she did not notice anything unusual about the operation of the plant, nor did she detect any odor, other than next to the intake and bar screen which is normal. She stated that the ponds were well maintained and had plenty of free board. The wastewater effluent spray fields located near the entrance to Rockbridge were adequately maintained. Witness Casselberry stated that is the Public Staff's opinion that the water and sewer systems in Southern Trace and Rockbridge are adequately maintained and operating properly.

Further, witness Casselberry testified that the Public Staff received six written complaints. She stated, in her prefiled direct testimony that the public hearing was held as scheduled and eleven customers testified. The two primary concerns in Southern Trace were water pressure and coloration of the water. Mr. Rains had concerns with the design of the system and operations. The primary complaints in Rockbridge Subdivision were response time to water leaks, system outages, water pressure, chlorine levels and the safety of the water. KRJ was required to file a report addressing customer complaints and concerns.

Witness Casselberry testified that on May 30, 2018, KRJ filed its Report on Customer Comments from Public Hearing in Raleigh, North Carolina as required by the Commission. She stated that she read the report and commended KRJ for its thorough response concerning customer complaints. Witness Casselberry stated that the Public Staff is satisfied with the Company's response to customer concerns, the implementation of its new procedures and policies to improve response times to leaks and customer complaints, and its commitment to install supervisory control and data acquisition (SCADA) control systems in Southern Trace and Rockbridge Subdivisions. Witness Casselberry concluded her testimony by stating that she had no further recommendations.

Conclusions Regarding Overall Quality of Service

Based upon the foregoing, and after careful review of the testimony of the customers at the public and evidentiary hearings, the testimony of Company witness Butler, the Report on Customer Comments provided by KRJ, and the Public Staff's engineering and service quality investigation, the Commission concludes that the overall quality of service provided by KRJ is adequate. In reaching this conclusion, the Commission notes that the Company has initiated certain important and significant customer communication and service policy changes in response to the testimony offered by customers at the public and evidentiary hearings.

Furthermore, the Commission notes that Public Staff witness Casselberry testified that none of the North Carolina environmental agency regional office personnel she contacted expressed any concerns with water quality or KRJ's operation of the water and sewer systems serving its customers. In addition, witness Casselberry stated that the water and sewer systems at Southern Trace and Rockbridge Subdivisions were observed, during her inspection, to be adequately maintained and operating properly. Witness Casselberry also testified that the Public Staff was satisfied with KRJ's report and the Company's "thorough response concerning customer complaints", as well as the implementation by KRJ of new procedures and policies to improve response times to leaks and customer complaints.

Notwithstanding the above observations, the Commission recognizes the validity of the customer complaints regarding specific service quality issues voiced at the hearings and does not intend, in any way, to minimize those complaints. With respect to the concerns expressed concerning communications with KRJ, the Commission strongly supports that customers must be able to quickly and easily voice their concerns to their utility company and also receive a timely response that their concern will be addressed as soon as possible or within a specified estimated time period. Otherwise, customers become frustrated and are likely not to report their concerns to the utility resulting in rate case proceedings being the first time the company, the Public Staff, and/or the Commission become aware of a quality of service concern. It is imperative that customers are able to communicate with the utility when a problem arises; that the utility respond to the customer without delay; and that the problem is addressed by the utility within a reasonable time period. The Company's newly-established e-mail account dedicated to the receipt and response to customer reports of service issues and other inquiries associated with water/sewer utility matters should help address this service-related concern. However, the Commission is of the opinion that KRJ should also seek to obtain and maintain the current email addresses and/or telephone numbers for its customers in Southern Trace and Rockbridge Subdivisions in order to better communicate with its customers concerning matters pertaining to their utility service. KRJ should also establish a process for customers to update KRJ concerning such contact information as needed.

Further, KRJ's newly-initiated protocol for providing for improved communication and coordination between the plant operating personnel, maintenance/construction supervisor, contract manager, and utility contractor used to make repairs to assure that all Company personnel are kept abreast of the situations as they evolve so that customer inquiries can be answered with the best information possible should also aid in addressing this service-quality concern expressed by the public witnesses.

The Commission acknowledges that the Public Staff testified it is satisfied with the Company's response to customer concerns and the implementation of new procedures and policies to improve response times to leaks and customer complaints. However, to ensure that these new procedures and policies are effective in improving KRJ's communications with customers and also aid in addressing the reported service-related concerns as expeditiously as possible, the Commission will require the Public Staff, not later than six months from the date of this Order, to follow up on the concerns expressed by customers of KRJ at the public and evidentiary hearings and file a report on the implementation status of the service improvements described in KRJ's report filed with the Commission on May 30, 2018.

With respect to the coloration of the water and low pressure issues expressed by the customers in Southern Trace Subdivision, the Commission encourages KRJ to continue its efforts to restore Well 2 to increased pumping capacity as soon as practicable to help alleviate these concerns. The Commission is of the opinion and therefore finds and concludes that KRJ should provide the Commission an update on a quarterly basis regarding the status of obtaining a contractor and once such contractor has been obtained, the estimated start date and completion date of the project. Such quarterly reporting should continue until KRJ has reported to the Commission the actual project completion date for restoring Well 2 to increased pumping capacity.

In regard to the concerns expressed by customers in Rockbridge Subdivision concerning the Company's response time to leaks, system outages, water pressure, chlorine levels, and the safety of the water, the Commission agrees with the Public Staff that KRJ's implementation of new procedures and policies should improve response time to leaks and other customer complaints. Moreover, the Company's newly-adopted protocols that require KRJ representatives to triage reported leaks as soon as possible, and determine the most appropriate level of response, which includes "immediate" and "next working day" response times, depending on the severity of the issue should adequately address customer customers. Further, following the hearing, KRJ expressly stated it has established a new policy that if a given service line presents a leak for two occasions, the line will be replaced rather than repaired. With respect to customer concerns regarding the safety of the water, the Commission notes that KRJ reported that the entire uranium issue was resolved with the installation of a uranium removal system which was placed into operation in June of 2016. KRJ stated that no uranium has been detected in finished water samples since that time and the gross alpha has fallen to levels well below those acceptable under the Safe Drinking Water Act.

Accordingly, the Commission, after careful review of the Company's detailed service report and KRJ witness Butler's testimony at the evidentiary hearing, concludes that the Company has acted in good faith to address and remedy service problems. The Commission also notes that some of the customers who testified at the public hearing voiced no current or ongoing service quality complaints which personally affected their utility service.

For the foregoing reasons, the Commission concludes that the overall quality of the water and sewer service provided by KRJ to its customers is adequate.

II. Cost of Capital

Public Staff witness Hinton testified by affidavit that the purpose of his affidavit was to recommend to the Commission a fair rate of return to be employed as a basis for determining the appropriate revenue requirement for KRJ to provide water utility service at Southern Trace Subdivision and water and sewer utility service at Rockbridge Subdivision in Wake County, North Carolina.

For the water utility service and the sewer utility service, witness Hinton recommended that KRJ be granted a 7.75% margin on operating revenue deductions or a 7.75% overall return on rate base. Witness Hinton testified that, after investigation, the Public Staff determined that (1) KRJ's reasonable level of operating expenses is greater than its rate base for Southern Trace water utility service and (2) for the Rockbridge Subdivision, the Company's utility rate base is greater than the reasonable level of operating expenses for both water and sewer utility service. As allowed under N.C. Gen. Stat. § 62-133.1, witness Hinton stated that he used the operating ratio method to evaluate KRJ's proposed rate increase for utility service in the Southern Trace Subdivision and that, as allowed under N.C. Gen. Stat. § 62-133, he used the rate base method to evaluate KRJ's proposed rate increase for utility service in the Rockbridge Subdivision.

Witness Hinton stated that, as outlined in Docket No. W-173, Sub 14, a Montclair Water Company docket, several factors should be considered when judging the adequacy of a return.

These are interest coverage, adequacy of the income level after interest expense, the level of inflation, and the quality of service.

In considering the Montclair factors in conjunction with this proceeding, witness Hinton testified that he did not incorporate any consideration with respect to quality of service. He stated that interest coverage has been provided at an adequate level; and that the level of inflation has been factored into the U.S. Treasury bond rate by investor expectations of the future levels of inflation. Witness Hinton opined that the recommended margin on expenses and overall return on rate base provide an adequate level of income after interest expense.

For these reasons, witness Hinton recommended to the Commission that KRJ be granted a 7.75% margin on operating revenue deductions and a 7.75% return on rate base.

In Paragraphs 4.C., 4.D., and 4.E. of the Stipulation, KRJ and the Public Staff stated the following in support of an authorized return of 7.75% in this proceeding:

> C. The Stipulating Parties stipulate and agree that an overall return on rate base and an operations margin of 7.75% are appropriate to use to establish rates in this proceeding. For purposes of this proceeding, this agreed overall rate of return is deemed by the Stipulating Parties to be a reasonable rate of return that will provide the Company with a reasonable opportunity, by sound management, to produce a fair return for its shareholders, considering changing economic conditions and other factors, to maintain its facilities and services in accordance with the reasonable requirements of its customers in the territory covered by its franchises, and to compete in the market for capital funds on terms that are fair to its customers and to its existing investors. Each of the Stipulating Parties further agrees that such stipulated overall rate of return, together with the Company's supported levels of rate base and operating expenses, results in a revenue requirement that is just and reasonable to the Company's customers in light of changing economic conditions.
>
> D. The overall rate of return that the Company should be allowed an opportunity to earn on its rate base in Rockbridge Subdivision is 7.75%.
>
> E. The Company should be allowed a 7.75% margin on operating revenue deductions requiring a return for the Southern Trace Subdivision, which results to an operating ratio of 92.97% (including taxes) or 92.81% (excluding taxes).

N.C. Gen. Stat. § 62-133(b)(4) requires the Commission to fix rates for service which will enable a public utility, by sound management, to produce a fair profit for its stockholders, in view of current economic conditions, maintain its facilities and services and compete in the market for capital, and no more. This is the ultimate objective of ratemaking. Utilities Commission v. General Telephone Company, 281 N.C. 318, 189 S.E.2d 705 (1972).

Accordingly, the Commission is of the opinion that, based on the affidavit submitted by Public Staff witness Hinton and the applicable provisions of the Stipulation as set forth above, there is adequate evidence in the record to support (a) the return of 7.75% agreed to by the Public Staff and KRJ and (b) a finding that such return should allow KRJ to properly maintain its facilities and services, provide adequate service to its customers, and produce a fair return, thus enabling the Company to attract capital on terms that are fair and reasonable to its customers and investors. Consequently, the Commission finds and concludes that the return of 7.75% that was agreed to by KRJ and the Public Staff is just and reasonable, should be approved, and is appropriate for use in this proceeding considering the impact of changing economic conditions on customers and relevant statutory and case law.

III. Overall Conclusions

At the evidentiary hearing, the Commission posed several questions to the Public Staff's witnesses for which late-filed exhibits were provided. In its late-filed exhibits, the Public Staff acknowledged that it had erroneously calculated the loss on disposal of property for both the Southern Trace and Rockbridge water systems. Further, the Public Staff stated that KRJ did not in any way contribute to these errors. The Public Staff did not quantity the revenue requirement amount of the errors, either individually for Southern Trace and Rockbridge Subdivisions or on a combined total company basis. Nevertheless, the Public Staff requested that the Commission approve in full the Stipulation as originally filed, including all of the revenue requirements that were achieved through good faith difficult negotiations. In support of its position, the Public Staff contended that KRJ had relinquished several significant issues that KRJ planned to litigate when it agreed to the Stipulation and that it would now be unfair to KRJ to lessen the agreed-upon revenue requirements as a result of these errors.

In response to the questions posed by the Commission at the evidentiary hearing, KRJ filed the Verified Affidavit and Late-Filed Exhibit of James R. Butler. In its affidavit, KRJ asserted that the Company would be materially impacted to the detriment of the Company if the amounts for loss on disposal of property were adjusted as a result of the discovery of these errors. KRJ submitted that, upon further review of its books and records, there were at least six additional instances of loss from disposal of equipment incurred by KRJ during the three-year period ending June 30, 2018, which could have been included for cost recovery in this case, but were not. KRJ detailed these additional losses from disposal of equipment in Attachment A to witness Butler's affidavit. Similar to the Public Staff, KRJ did not quantify the revenue requirement amount of these errors or the amount by which the six additional instances of loss on disposal of equipment would mitigate the revenue requirement impact; but rather, maintained that the Stipulation as originally filed, which was agreed to only after intense and extensive negotiations with the Public Staff, is fair to both the Company and its customers.

The Commission recognizes that, to date, the parties have expended considerable time, effort, and expense to achieve a settlement in this proceeding. The Commission notes that Paragraph 15 of the Stipulation states that "no portion of this Stipulation shall be binding on the Stipulating Parties unless the entire Stipulation is accepted by the Commission". In general, the Commission encourages the various parties in a general rate case proceeding to work together to reach a stipulation, if possible. Such stipulations provide benefits to both the utility and its customers. However, in this particular rate case proceeding, the Commission is aware that errors exist in the Stipulation. The Commission acknowledges that if the parties were to engage in further negotiations at this point in time, it would likely materially increase the amount of rate case expense to be included in the new rates that would ultimately be approved for customers. Moreover, the Commission notes that the Public Staff, the consumer advocate for customers in this proceeding, who was a party to the lengthy and difficult settlement negotiations, continues to support Commission approval of the Stipulation as originally filed notwithstanding acknowledgment of its errors.

At this juncture, the Commission is of the opinion that it would be beneficial to both the Company and its customers for the Commission to accept the Stipulation of KRJ and the Public Staff as originally filed. Although the Commission is not bound to accept the Stipulation as filed, based upon all evidence of record, the Commission finds and concludes that the Stipulation represents a reasonable result for both KRJ and its customers. The Commission observes that in reaching a stipulation with the Public Staff in this proceeding KRJ has agreed to accept, without further litigation before the Commission and resulting rate case expense, a 43.3% increase in total operating revenues for Southern Trace Subdivision when it applied for a 81.8% increase and a 10.5% increase in total operating revenues for Rockbridge Subdivision (Water and Sewer Operations combined) when it applied for a total increase of 72.2%.

However, in light of the errors identified in the Public Staff's testimony and exhibits and the Company's statement that KRJ would be materially impacted to the detriment of the Company if the amounts for loss on disposal of property were adjusted as a result of the discovery of the errors, and that the additional instances of loss on disposal provided by KRJ witness Butler in his Verified Affidavit, which would likely mitigate these errors, have not been reviewed and accepted by the Public Staff, the Commission is of the opinion that it would be reasonable and appropriate to require KRJ to not file a general rate case prior to October 10, 2019, with changes in rates effective no sooner than August 6, 2020. This condition, imposed by the Commission, attached to the Stipulation as originally filed would benefit both customers and the Company. Customers would be shielded from the possibility of further rate increases for the next two years and KRJ would be able to implement the stipulated rates effective upon issuance of this Order.

Therefore, after carefully reviewing the Stipulation and all of the evidence of record, including the Late-Filed Exhibits filed by Public Staff witnesses Morgan and Casselberry and the Verified Affidavit and Late-Filed Exhibit filed by KRJ witness Butler, and with the condition that KRJ would not have any further general rate case increases for the next two years, the Commission finds and concludes that the Stipulation is the product of the give-and-take settlement negotiations between KRJ and the Public Staff; that the Stipulation constitutes material evidence; that the Stipulation is entitled to be given appropriate weight in this proceeding, along with all other evidence in the record; and that the Stipulation is fully supported by competent evidence in the record.

Accordingly, based on the foregoing findings of fact and the entire record in this proceeding, the Commission concludes that the stipulated rates, the stipulated rate of return of 7.75%, and all of the other provisions of the Stipulation, which are incorporated herein by reference, are just and reasonable and should be approved. Further, KRJ should not file a general rate case prior to October 10, 2019, with changes in rates effective no sooner than August 6, 2020.

IT IS, THEREFORE, ORDERED as follows:

1. That the Stipulation filed by KRJ and the Public Staff in this docket on June 7, 2018, as amended on June 14, 2018, is incorporated by reference herein and is hereby approved in its entirety with the condition imposed by the Commission discussed hereinabove and expressly stated in Decretal Paragraph No. 15 hereinbelow.

2. That the Schedules of Rates, attached hereto as Appendices A-1 and A-2, are hereby approved and deemed to be filed with the Commission pursuant to N.C. Gen. Stat. § 62-138.

3. That the Schedules of Rates, attached hereto as Appendices A-1 and A-2, are hereby authorized to become effective for service rendered on and after the issuance date of this Order.

4. That the Notice to Customers, attached hereto as Appendix B, shall be mailed with sufficient postage or hand delivered to all affected customers in conjunction with KRJ's next regularly scheduled billing process.

5. That KRJ shall file the attached Certificate of Service, properly signed and notarized, not later than 10 days after the Notice to Customers is mailed or hand delivered to customers.

6. That, with the exception of Stipulation Paragraph 4.G. discussed in Decretal Paragraph 7 below, the Stipulation, and the parts of this Order pertaining to the contents of that agreement shall not be cited or treated as precedent in future proceedings.

7. That, in the next general rate case filed by KRJ for the Company's Southern Trace and Rockbridge service areas, the stipulated amounts agreed to in this case, as approved herein by the Commission, for plant in service, accumulated depreciation, contributions in aid of construction, depreciation and amortization expense, and original cost rate base, shall be used as the starting point for the Company's rate case application and the Public Staff's investigation.

8. That the provision whereby KRJ is currently required, pursuant to Commission Order in Docket No. W-1075, Sub 5, to disclose the current Rockbridge Subdivision water and sewer rates in marketing materials, with lot purchase agreements, and in the restrictive covenants pertaining to all lots in the Rockbridge Subdivision, to notify future customers in Rockbridge of the utility rates prior to their purchasing their lots or residences, is hereby rescinded.

9. That the provision whereby KRJ is currently required, pursuant to Commission Order in Docket No. W-1075, Sub 5, to file annual reports, beginning on October 31, 2007, on the status of the Rockbridge Subdivision and utility system, is hereby rescinded.

10. That Docket No. W-1075, Sub 5 is hereby closed.

11. That the Late-Filed Exhibits filed by Public Staff witnesses Morgan and Casselberry and the Verified Affidavit and Late-Filed Exhibit filed by KRJ witness Butler are hereby admitted in evidence in this proceeding.

12. That, not later than six months from the date of this Order, the Public Staff shall follow up on the concerns expressed by customers of KRJ at the public and evidentiary hearings and shall file a report on the implementation status of the service improvements described in KRJ's report filed with the Commission on May 30, 2018.

13. That in order to facilitate improved electronic, voice, and/or written communications between the Company and its customers, within 30 days of the issuance date of this Order, KRJ shall seek to obtain the current email addresses and/or telephone numbers of its customers in Southern Trace and Rockbridge Subdivisions. The Company shall file a written report with the Commission not later than six months after the issuance date of this Order detailing the status of obtaining such contact information. Such report shall also state the process established for a customer to notify KRJ when needed concerning any future changes to a customer's contact information.

14. That KRJ shall update the Commission on a quarterly basis concerning the status of the project to restore Well 2 in Southern Trace to increased pumping capacity. The first quarterly report shall be filed on or before October 15, 2018, for the quarter ending September 30, 2018. Such quarterly reporting shall continue until the actual project completion date has been reported by KRJ.

15. That KRJ shall not file a general rate case prior to October 10, 2019, with changes in rates effective no sooner than August 6, 2020 (after a six-month suspension period under N.C. Gen. Stat. § 62-134).

ISSUED BY ORDER OF THE COMMISSION.
This the 6th day of August, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

APPENDIX A-1

SCHEDULE OF RATES
For

KRJ, INC., D/B/A KRJ UTILITIES
for providing water utility service

in
SOUTHERN TRACE SUBDIVISION
Wake County, North Carolina

Monthly Metered Water Rates:

Base charge, zero usage	$ 19.12
Usage charge, per 1,000 gallons	$ 5.44

WATER AND SEWER – RATE INCREASE

Tap on Fee:	$500.00 per REU

Reconnection Charges:

If water service is cut off by utility for good cause	$25.00
If water service cut off by utility at customer's request	$20.00

Returned Check Charge:	$25.00
Bills Due:	On billing date
Bills Past Due:	15 days after billing date
Billing Frequency:	Shall be monthly for service in arrears
Finance Charge For Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after the billing date

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Issued in Accordance with Authority by the North Carolina Utilities Commission in Docket No. W-1075 Sub 12, on this the 6th day of August, 2018.

APPENDIX A-2
PAGE 1 OF 2

SCHEDULE OF RATES
for
KRJ, INC., D/B/A KRJ UTILITIES
for providing water and sewer utility service
in
ROCKBRIDGE SUBDIVISION
Wake County, North Carolina

Monthly Metered Water Rates:

Base charge, zero usage	$16.30
Usage charge, per 1,000 gallons	$ 5.41

Monthly Flat Sewer Rate:	$58.25

Availability Rates: [1/]

Water monthly availability rate	$15.00
Sewer monthly availability rate	$70.00

Tap-on Fee:

Water, per REU	$1,000
Sewer, per REU	$8,000

Reconnection Charges:

If water service is cut off by utility for good cause	$15.00
If water service cut off by utility at customer's request	$15.00

Returned Check Charge:	$25.00
Bills Due:	On billing date
Bills Past Due:	15 days after billing date
Billing Frequency:	Shall be monthly for service in arrears

APPENDIX A-2
PAGE 2 OF 2

Finance Charge For Late Payment: 1% per month will be applied to the unpaid balance of all bills still past due 25 days after the billing date

Note:

1/ Developer shall pay monthly availability fees on all lots not receiving service once plat creating lots is recorded.

Issued in Accordance with Authority by the North Carolina Utilities Commission in Docket No. W-1075 Sub 12, on this the 6th day of August, 2018.

APPENDIX B
PAGE 1 OF 2

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-1075, SUB 12

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing KRJ, Inc., d/b/a KRJ Utilities to increase rates for water utility service in the Southern Trace and Rockbridge Subdivisions and to decrease the rate for sewer utility service in the Rockbridge Subdivision, effective for service rendered on and after the date of this Notice. The new approved rates are as follows:

Southern Trace Subdivision

Monthly Metered Water Rates:

Base charge, zero usage	$19.12
Usage charge, per 1,000 gallons	$ 5.44

Reconnection Charges:

If water service is cut off by utility for good cause	$25.00
If water service cut off by utility at customer's request	$20.00

Returned Check Charge: $25.00

Rockbridge Subdivision

Monthly Metered Water Rates:

Base charge, zero usage	$16.30
Usage charge, per 1,000 gallons	$ 5.41

Monthly Flat Sewer Rate: $58.25

APPENDIX B
PAGE 2 OF 2

Reconnection Charges:

If water service is cut off by utility for good cause	$15.00
If water service cut off by utility at customer's request	$15.00

Returned Check Charge: $25.00

ISSUED BY ORDER OF THE COMMISSION.
This the 6th day of August, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

WATER AND SEWER – RATE INCREASE

CERTIFICATE OF SERVICE

I, ______________________________________, mailed with sufficient postage or hand delivered to all affected customers the attached Notice to Customers issued by the North Carolina Utilities Commission in Docket No. W-1075, Sub 12, and such Order was mailed or hand delivered by the date specified in the Order.

This the ___ day of ______________, 2018.

By: ___________________________________

Signature

____

Name of Utility Company

The above named Applicant, ______________________________, personally appeared before me this day and, being first duly sworn, says that the required Notice to Customers was mailed or hand delivered to all affected customers, as required by the Commission Order dated ________________________ in Docket No. W-1075, Sub 12.

Witness my hand and notarial seal, this the ___ day of ____________, 2018.

____

Notary Public

____

Printed Name

____

Date

(SEAL) My Commission Expires:

DOCKET NO. W-1166, SUB 17

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by MECO Utilities, Inc., Post Office Box 2359, Swansboro, North Carolina 28584-2359, for Authority to Increase Rates for Water and Sewer Utility Service in Mobile Estates Mobile Home Park in Wake County, North Carolina	)	ORDER GRANTING PARTIAL RATE INCREASE AND REQUIRING CUSTOMER NOTICE

BY THE COMMISSION: On October 31, 2017, MECO Utilities, Inc. (MECO or Applicant), filed a letter notifying the Commission of its intent to file a general rate case as required by Commission Rule R1-17(a). On December 4, 2017, MECO filed an application with the Commission seeking authority to increase its rates for providing water and sewer utility service in Mobile Estates Mobile Home Park (Mobile Estates) in Wake County, North Carolina. By Order dated December 18, 2017, the Commission established a general rate case, suspended rates, scheduled hearing, and required customer notice. The Notice to Customers stated that the March 22, 2018 public hearing may be canceled and the matter decided on the filings if no significant protests are received from consumers on or before February 15, 2018.

On December 21, 2017, MECO filed its certificate of service. The notice period expired on February 15, 2018. No customer protests were received.

On March 2, 2018, the Public Staff – North Carolina Utilities Commission (Public Staff) filed the Affidavit of Calvin C. Craig, III, Financial Analyst, Economic Research Division, and the testimony and exhibits of Manasa L. Cooper, Staff Accountant, Water/Communications Section, Accounting Division, and Gina Y. Casselberry, Utilities Engineer, Water, Sewer, and Communications Division.

On March 9, 2018, the Public Staff filed a Stipulation dated March 8, 2018, executed by MECO and the Public Staff (the Stipulation) in which MECO agreed to accept the Public Staff's recommended annual revenue requirements and recommended rates. The Stipulation further stated that: (1) MECO does not contest any of the Public Staff adjustments, but reserves the right to contest the adjustments, or similar adjustments, in future MECO proceedings including general rate cases; (2) MECO and the Public Staff agree that the scheduled March 22, 2018 evidentiary hearing should be canceled and customer notice given; (3) MECO and the Public Staff agree that the Public Staff will prepare a proposed order, which MECO shall review and agree to prior to filing with the Commission; (4) MECO and the Public Staff request that the Commission issue the rate case order as soon as reasonable practical, after the filing of the proposed order, and waive the 15-day period to file exceptions, so that the Commission approved rates will be effective on and after the date of the Commission's order.

Also, on March 9, 2018, the Public Staff filed a motion to cancel the hearing which had been scheduled for Thursday, March 22, 2018. On March 12, 2018, the Commission issued an

Order canceling the Thursday, March 22, 2018 hearing and requiring customer notice. On March 15, 2018, MECO filed its certificate of service indicating that customer notice had been provided as required by the March 12, 2018 Order.

On April 10, 2018, MECO and the Public Staff filed a Joint Proposed Order.

Based upon the verified application, the Stipulation, the affidavit of Public Staff witness Craig, the testimony and exhibits of Public Staff witnesses Cooper and Casselberry, and the Commission's files and records, the Commission is of the opinion that the provisions of the Stipulation are just and reasonable. Accordingly, the Commission makes the following

FINDINGS OF FACT

1. MECO is a public utility as defined by G.S. 62-3(23) and is before the Commission pursuant to its application for an increase in its rates and charges for water and sewer utility service under G.S. 62-137.

2. The test year established for use in this proceeding is the 12-month period ended September 30, 2017.

3. MECO provides water and sewer utility service to approximately 271 customers in Mobile Estates Mobile Home Park in Wake County, North Carolina.

4. MECO provides utility service by purchasing bulk water and bulk sewer treatment from the Town of Cary.

5. The present rates have been in effect since August 21, 2017, pursuant to a Commission Order Approving Tariff Revision and Requiring Customer Notice issued on that same date in Docket No. W-1166, Sub 16, which was MECO's last pass through rate increase from the Town of Cary.

6. MECO's present rates and the Applicant's proposed rates are as follows:

Monthly Metered Water Service:	Present	Proposed
Base charge, zero usage	$ 13.81	$ 16.50
Usage charge, per 1,000 gallons	$ 6.44	$ 7.69

Monthly Metered Sewer Service:	Present	Proposed
Base charge, zero usage	$ 12.14	$ 16.09
Usage charge, per 1,000 gallons	$ 9.96	$ 13.20

7. Under the Applicant's proposed rates, the average combined water and sewer monthly bill would increase from $84.17 to $106.75, or 26.8%, based on the average monthly usage of 3,550 gallons.

WATER AND SEWER – RATE INCREASE

8. MECO and the Public Staff entered into a Stipulation on March 8, 2018, which was filed with the Commission on March 9, 2018, that settled all their issues. MECO and the Public Staff are the only formal parties to this proceeding.

9. Paragraph No. 7 of the Stipulation contains the provision that MECO does not contest any of the Public Staff's adjustments, but reserves the right to contest the adjustments, or similar adjustments, in future MECO proceedings including general rate cases.

10. The Applicant is providing adequate service to its customers.

11. The reasonable original cost rate base for use in this proceeding is $4,268 for water operations and $2,135 for sewer operations, both of which are entirely comprised of cash working capital.

12. The Applicant's total annual operating revenues under present rates for the 12-month period ended September 30, 2017, are shown below:

	Service Revenues	Other Revenues & Uncollectibles	Total Operating Revenues
Water Operations:	$118,945	($313)	$118,632
Sewer Operations:	$153,981	($421)	$153,560

13. The Applicant's total annual operating revenues under proposed rates for the 12-month period ended September 30, 2017, are shown below:

	Service Revenues	Other Revenues & Uncollectibles	Total Operating Revenues
Water Operations:	$142,063	($313)	$141,750
Sewer Operations:	$204,074	($421)	$203,653

14. By its application, MECO requested a total annual increase in its water and sewer utility service rates of $73,211, which would produce the following additional annual service revenues and percentage increases:

Water Operations:	$23,118	19.4%
Sewer Operations:	$50,093	32.5%

15. It is reasonable and appropriate to include total rate case costs of $6,695 related to this rate case proceeding, amortized over three years, resulting in annual rate case expense of $2,232. It is reasonable and appropriate to allocate the annual amount of rate case expense of $2,232 between water and sewer operations, based upon a 50/50 allocation factor resulting in annual rate case expense for water operations of $1,116 and for sewer operations of $1,116.

16. The appropriate levels of operations and maintenance (O&M) expenses for use in this proceeding are as follows:

Water Operations:	$111,374
Sewer Operations:	$162,997

17. Since the entire amount of the original cost rate base for both water and sewer operations is comprised entirely of cash working capital, the appropriate level of depreciation expense for use in this proceeding is $0 for water operations and $0 for sewer operations.

18. It is reasonable and appropriate to calculate regulatory fees using the statutory rate of 0.14%.

19. It is reasonable and appropriate to calculate federal income taxes based upon the adjusted levels of revenues and expenses and the statutory corporate rate of 21% prescribed in the Tax Cut and Jobs Act of 2017, which became effective January 1, 2018.

20. It is reasonable and appropriate to calculate state income taxes based upon the adjusted levels of revenues and expenses, and the State corporate income tax rate of 3%, which became effective January 1, 2017.

21. The operating ratio method, which allows a return on operating revenue deductions, is the proper method for determining MECO's water and sewer revenue requirements.

22. The Public Staff recommended a 7.50% margin on expenses, which results in an operating ratio of 93.18% (including taxes) or 93.02% (excluding taxes) for water operations and for sewer operations.

23. The 7.50% margin on expenses is just and reasonable for use in this general rate case proceeding.

24. The operating revenue deductions requiring a return (total operating expenses, excluding regulatory fee and income taxes) are $111,461 for water operations and $163,110 for sewer operations.

25. The total annual revenues necessary to allow MECO the opportunity to earn the 7.50% return found just and reasonable are as follows:

	Service Revenues	Other Revenues & Uncollectibles	Total Operating Revenues
Water Operations:	$122,855	($313)	$122,542
Sewer Operations:	$179,746	($421)	$179,325

26. The agreed-upon rates will provide MECO with a total increase in its annual level of service revenues of $29,675, consisting of an increase for water operations of $3,910 (an increase of 3.3%) and an increase for sewer operations of $25,765 (an increase of 16.8%).

27. The water and sewer service rates agreed to by MECO and the Public Staff as provided in Paragraph No. 5 of the Stipulation and in Casselberry Exhibit No. 4, and are as follows:

WATER AND SEWER – RATE INCREASE

Metered Water Residential Service:	
Base charge, zero usage	$ 14.03
Usage charge, per 1,000 gallons	$ 6.72
Metered Sewer Residential Service:	
Base charge, zero usage	$ 10.42
Usage charge, per 1,000 gallons	$ 12.69

28. Since MECO is a purchased water and sewer treatment system it is appropriate and reasonable to calculate the water and sewer usage charges based upon the cost for purchased water and sewer treatment from the Town of Cary.

29. MECO should be allowed to increase its returned check charge for processing non-sufficient-funds (NSF) checks from $23.91 to $25.00. It is also reasonable and appropriate to authorize the Applicant to increase its disconnection/reconnection charge from $14.35 for water operations and $14.05 for sewer operations to $15.00 for both water and sewer operations when made during scheduled working hours and from $28.68 for water operations and $28.09 for sewer operations to $30.00 for both water and sewer operations when made during after-hours on normal workdays or in an emergency action on weekends or holidays.

30. The Schedule of Rates for water and sewer utility service agreed to by MECO and the Public Staff, as provided in Appendix A of the Joint Proposed Order filed on April 10, 2018, and attached hereto as Appendix A, is just and reasonable and should be approved.

31. Under the Schedule of Rates approved herein, the average combined water and sewer monthly bill will increase from $84.17 to $93.36, or 10.9%, based on the average monthly usage of 3,550 gallons.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 THROUGH 7

The evidence supporting these findings of fact is contained in the Commission's records, the verified application, and the testimony and exhibits of Public Staff witnesses Cooper and Casselberry. These findings are primarily jurisdictional and informational and are uncontested.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8 AND 9

The evidence supporting these findings of fact is contained in the Stipulation between MECO and the Public Staff entered into on March 8, 2018, and filed with the Commission on March 9, 2018.

On March 9, 2018, the Public Staff filed a Stipulation dated March 8, 2018, executed by MECO and the Public Staff in which MECO agreed to accept the Public Staff's recommended annual revenue requirements and recommended rates. Further, the Stipulation stated, among other things, that although MECO does not contest any of the Public Staff adjustments in this proceeding, MECO reserves the right to contest the adjustments, or similar adjustments, in future MECO proceedings including general rate cases.

Based upon the foregoing findings of fact and the entire record in this proceeding, the Commission finds and concludes that the provisions of the Stipulation filed on March 9, 2018 are just and reasonable and that the levels of rate base, revenues, and expenses set forth in Cooper Exhibit I, which are incorporated herein by reference, recommended by the Public Staff and agreed to by MECO are the appropriate levels for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence supporting this finding of fact is contained in the affidavit of Public Staff witness Casselberry and in the Commission's records.

Public Staff witness Casselberry testified that Mobile Estates is a mobile home park located in the Town Limits of Cary, in Wake County, North Carolina, on the east side of Maynard Road, approximately 400 yards south of the intersection of Maynard and Chatham Streets. She observed that the mobile home park has approximately 276 rental spaces and at September 30, 2017, MECO provided water and sewer utility service to 271 customers. Further, witness Casselberry testified that MECO purchases water and sewer treatment from the Town of Cary.

Moreover, witness Casselberry stated that there have been no customer protests and the Public Staff has not discovered any service problems. Witness Casselberry concluded, based upon her investigation, that the Applicant is providing adequate service to its customers.

Based upon the foregoing, the Commission finds and concludes that the quality of water and sewer utility service provided by the Applicant to its customers is adequate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence supporting this finding of fact is contained in the Commission's records, the verified application, and in the testimony and exhibit of Public Staff witness Cooper.

The adjustments made by the Public Staff to the Applicant's original cost rate base for water operations included adjustments to plant in service, accumulated depreciation, and cash working capital and for sewer operations included an adjustment to cash working capital.

Witness Cooper testified that the amount of original cost plant in service provided by the Applicant in its application was \$6,754 for water operations and \$0 for sewer operations. She stated that in response to a Public Staff data request, it was discovered that the \$6,754 amount for water operations was regulatory commission expense from Docket No. W-1166, Sub 8 (Sub 8 Proceeding), the Applicant's last general rate case proceeding. Witness Cooper pointed out that regulatory commission expense should not have been included in plant in service by the Applicant. She removed this amount from plant in service which resulted in \$0 plant in service for water operations.

Further, witness Cooper determined based upon a formal inquiry to the Applicant that there have been no additions to water or sewer plant in service since the Sub 8 Proceeding. As a result, witness Cooper recommended \$0 net plant in service for both water and sewer operations for purposes of this proceeding.

Witness Cooper stated that the Public Staff included 1/8 of total operations and maintenance expenses, less purchased water and sewer expense, in original cost rate base as a measure of cash working capital which provides the Applicant with the funds necessary to carry on the day-to-day operations of the water and sewer utility business.

The adjustments made by witness Cooper to the various components of original cost rate base resulted in an amount of original cost rate base for use in this proceeding of $4,268 for water operations and $2,135 for sewer operations, both of which consist entirely of cash working capital.

In the Stipulation between the Public Staff and MECO filed on March 9, 2018, MECO agreed to accept the Public Staff's recommended annual revenue requirements and rates. Further, MECO did not contest any of the Public Staff's adjustments in this proceeding but reserved the right to contest the adjustments or similar adjustments in future MECO proceedings, including general rate cases.

Based upon the foregoing, the Commission finds and concludes that the appropriate level of original cost rate base for use in this proceeding is $4,268 for water operations and $2,135 for sewer operations.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12 THROUGH 14

The evidence supporting these findings of fact is contained in the Commission's records, the verified application, the testimony and exhibits of Public Staff witnesses Cooper and Casselberry.

Witness Casselberry calculated annual water service revenues of $118,945 under the current Commission-approved rates and $142,063 under the Applicant's proposed rates. Further, witness Casselberry calculated annual sewer service revenues of $153,981 under the current Commission-approved rates and $204,074 under the Applicant's proposed rates.

Witness Cooper calculated miscellaneous revenues of $425 for water operations and $549 for sewer operations. She included bad debt expense of ($738) for water operations and ($970) for sewer operations.

Pursuant to Paragraph No. 7 of the Stipulation, the Applicant does not contest any of the Public Staff's adjustments, but reserves the right to contest the adjustments, or similar adjustments, in future MECO proceedings, including general rate cases.

Based upon the foregoing, the Commission finds and concludes that the appropriate levels of total annual operating revenues at present and proposed rates for use in this proceeding for water operations are $118,632, consisting of $118,945 in service revenues, $425 in other revenues, and ($738) for bad debt expense, and for sewer operations are $153,560, consisting of $153,981 in service revenues, $549 in other revenues, and ($970) in bad debt expense.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15 AND 16

The evidence supporting these findings of fact is contained in the Commission's records and in the testimony and exhibits of Public Staff witnesses Cooper and Casselberry. The following table summarizes the amounts that the Public Staff recommended for inclusion in determining the proper level of total O&M expenses for use in this proceeding for water and sewer operations:

Item	Water Amount	Sewer Amount
Contract operating services	$23,663	$15,739
Maintenance and repairs	395	0
Purchased water	77,231	0
Purchased sewer	0	145,920
Testing	7,116	0
Permit fees and licenses	1,681	0
Other expense	172	222
Rate case expense	1,116	1,116
Total O&M expenses	$111,374	$162,997

The Public Staff made adjustments to the levels of contract operating services, maintenance and repairs, testing, permit fees and licenses, purchased water, and purchased sewer based upon recommendations by witness Casselberry. Witness Cooper stated that the Applicant did not include an amount for rate case expense in its application. Witness Cooper explained that she calculated an amount of rate case expense for this proceeding based upon the cost of the filing fee, the costs for copying and mailing notices to customers, legal fees, and contract management fees. Witness Cooper recommended that the total rate case costs of $6,695 be amortized over three years resulting in annual rate case expense of $2,232. She recommended that the annual rate case expense be allocated between water and sewer operations based upon a 50/50 allocation factor which resulted in annual rate case expense of $1,116 for water operations and $1,116 for sewer operations.

In the Stipulation between the Public Staff and MECO filed on March 9, 2018, MECO did not contest any of the Public Staff's adjustments in this proceeding but reserved the right to contest the adjustments or similar adjustments in future MECO proceedings, including general rate cases. Further, in the Stipulation, MECO agreed to accept the Public Staff's recommended annual revenue requirements and recommended rates.

Based upon the foregoing, the Commission finds and concludes that the appropriate level of O&M expenses for use in this proceeding is for water operations is $111,374 for water operations and $162,997 for sewer operations.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 17 THROUGH 20

The evidence supporting these findings of fact is contained in the Commission's records, and in the testimony and exhibits of Public Staff witnesses Cooper and Casselberry. The following table summarizes the amounts that the Public Staff recommended for inclusion in determining the proper level of total ongoing depreciation expense and taxes for use in this proceeding:

WATER AND SEWER – RATE INCREASE

Item	Water Amount	Sewer Amount
Depreciation expense	$ 0	$ 0
Other taxes	87	113
Regulatory fees	172	251
State income taxes	327	479
Federal income taxes	2,222	3,252
Total depreciation and taxes	$ 2,808	$ 4,095

The Public Staff made adjustments to the levels of depreciation expense, other taxes, regulatory fees, and state and federal income taxes. In the Stipulation between the Public Staff and MECO filed with the Commission on March 9, 2018, MECO did not contest any of the Public Staff's adjustments in this proceeding but reserved the right to contest the adjustments or similar adjustments in future MECO proceedings, including general rate cases.

Based upon the foregoing, the Commission finds and concludes that the appropriate level of depreciation expense and taxes for use in this proceeding is $2,808 for water operations and $4,095 for sewer operations.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 21 THROUGH 26

The evidence supporting these findings of fact is contained in the Commission's records, the verified application, the affidavit of Public Staff Financial Analyst Craig, and the testimony and exhibits of Public Staff witnesses Cooper and Casselberry.

With respect to the Applicant's rate increase request for water operations, witness Cooper testified that based upon her investigation, the Applicant's original cost rate base at September 30, 2017, is $4,268 and the level of operating revenue deductions requiring a return (total operating expenses excluding regulatory fees and income taxes) is $111,461. Witness Cooper stated that pursuant to G.S. 62-133.1, she used the operating ratio method to evaluate the Applicant's proposed revenue requirement for water operations. She calculated an increase in the gross revenue requirement using the overall rate of return of 7.50%, the reasonable rate recommended by Public Staff Financial Analyst Craig. Witness Cooper stated that the resulting total revenue requirement for water operations would be $122,542, of which $122,855 is service revenues. She recommended that water service rates be set to reflect a $3,910 increase, resulting in an annual level of water service revenues of $122,855.

In regard to MECO's rate increase request for sewer operations, witness Cooper testified that based upon her investigation, the Applicant's original cost rate base at September 30, 2017, is $2,135 and the level of operating revenue deductions requiring a return (total operating expenses excluding regulatory fees and income taxes) is $163,110. Witness Cooper stated that pursuant to G.S. 62-133.1, she used the operating ratio method to evaluate the Applicant's proposed revenue requirement for sewer operations. She calculated an increase in the gross revenue requirement using the overall rate of return of 7.50%, the reasonable rate recommended by Public Staff Financial Analyst Craig. Witness Cooper stated that the resulting total revenue requirement for sewer operations would be $179,325, of which $179,746 is service revenues. She recommended that sewer service rates be set to reflect a $25,765 increase, resulting in an annual level of sewer service revenues of $179,746.

For both water operations and sewer operations, Financial Analyst Craig recommended that MECO be granted a 7.50% margin on expenses, which relates to an operating margin of 93.18% (including taxes) or 93.02% (excluding taxes). He stated that his recommendation was based upon his investigation of the cost of capital for small water and sewer companies. Further, he recommended that the operating ratio method, as allowed under G.S. 62-133.1, be used to evaluate MECO's proposed rate increase as the Public Staff determined during its investigation that MECO's rate base is less than the reasonable level of operating expenses.

Financial Analyst Craig explained that, as outlined in Docket No. W-173, Sub 14, Montclair Water Company, several factors should be considered when judging the adequacy of return. Such factors include interest coverage, adequacy of the income level after interest expense, the level of inflation, and the quality of service. Financial Analyst Craig contended that interest coverage has been provided at an adequate level, that the level of inflation has been factored into the U.S. Treasury bond rate by investor expectations of the future levels of inflation. He opined that the Public Staff's recommended margin on expenses would provide an adequate level of income after interest expense. Further, Financial Analyst Craig commented that in considering these factors in conjunction with this proceeding, he has not incorporated any consideration with respect to quality of service.

Moreover, witness Casselberry testified that, based upon her investigation, the Public Staff concludes that MECO should be granted a partial rate increase for providing water and sewer utility service. Witness Casselberry recommended that service revenues should be increased to reflect annual service revenues of $122,855 for water operations and $179,746 for sewer operations.

In the Stipulation between the Public Staff and MECO filed on March 9, 2018, MECO did not contest any of the Public Staff's adjustments in this proceeding but reserved the right to contest the adjustments or similar adjustments in future MECO proceedings, including general rate cases. Further, in the Stipulation, MECO agreed to accept the Public Staff's recommended annual revenue requirements and recommended rates.

Based upon the foregoing, the Commission finds and concludes that the operating ratio method is the appropriate method for evaluating the Applicant's proposed revenue requirement and that the 7.50% operating margin on expenses recommended by Financial Analyst Craig is just and reasonable and should be approved. Consequently, the Commission finds and concludes that MECO should be allowed to increase its rates so as to produce total annual operating revenues of $122,542 for water operations and $179,325 for sewer operations.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 27 THROUGH 31

The evidence supporting these findings of fact is contained in the Commission's records, the verified application, the affidavit of Public Staff Financial Analyst Craig, the testimony and exhibits of Public Staff witnesses Cooper and Casselberry, and the Joint Proposed Order.

WATER AND SEWER – RATE INCREASE

Witness Casselberry testified that MECO is a purchased water and sewer treatment system. As a result, witness Casselberry calculated the Public Staff's recommended water and sewer usage charges based upon the cost for purchased water and sewer treatment from the Town of Cary. She commented that the Public Staff's recommended base charges for water and sewer utility service reflects the remaining expenses associated with providing water and sewer utility service. Witness Casselberry explained that by setting MECO's usage charges for water and sewer based on purchased water and sewer treatment costs from the Town of Cary, should MECO request a pass through, any increase to the usage charges would be directly associated with the increased cost from the Town of Cary for purchased water and sewer treatment.

In regard to miscellaneous charges, in its application the Applicant requested approval to increase its returned check charge from $23.91 to $25.00 and its disconnection/reconnection charge from $14.35 for water operations and $14.05 for sewer operations to $15.00 for both water and sewer operations when made during scheduled working hours and from $28.68 for water operations and $28.09 for sewer operations to $30.00 for both water and sewer operations when made during after-hours on normal workdays or in an emergency action on weekends or holidays. The Public Staff reviewed the Applicant's request to increase these miscellaneous charges and found that the proposed returned check charge and disconnection/reconnection fees to be fair and reasonable. Accordingly, the proposed increases to the returned check charge and the disconnection/reconnection fees were included in Appendix A of the Joint Proposed Order filed with the Commission by MECO and the Public Staff.

Therefore, the Commission finds and concludes that it is reasonable and appropriate to authorize MECO to increase its returned check charge for processing non-sufficient-funds (NSF) checks and its disconnection/reconnection charges as requested by the Applicant and recommended by the Public Staff.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

The Commission, having carefully reviewed the Stipulation and all of the evidence of record, finds and concludes that the Stipulation is the product of the give-and-take settlement negotiations between MECO and the Public Staff; that it constitutes material evidence; that it is entitled to be given appropriate weight in this proceeding, along with the other evidence in the record; and that it is fully supported by the record. Accordingly, based upon the foregoing findings of fact and the entire record in this proceeding, the Commission concludes that the stipulated revenue requirements, stipulated rates, and all the other provisions of the Stipulation entered on March 8, 2018, and filed with the Commission on March 9, 2018, which are incorporated herein by reference, are just and reasonable and should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That the application for rate increase filed by MECO Utilities, Inc., on December 4, 2017; the affidavit of Public Staff Financial Analyst Calvin C. Craig, III, and testimony and exhibits of Public Staff witnesses Manasa L. Cooper, Staff Accountant, Accounting

Division and Gina Y. Casselberry, Utilities Engineer, Water, Sewer, and Communications Division filed by the Public Staff on March 2, 2018; and the Stipulation between MECO Utilities, Inc. and the Public Staff filed on March 9, 2018, in this docket are hereby received as evidence in this proceeding.

2. That MECO Utilities, Inc., is authorized to increase its rates and charges for providing water and sewer utility service in Mobile Estates Mobile Home Park in Wake County, North Carolina, as reflected in the Schedule of Rates, attached hereto as Appendix A. These rates and charges shall be effective for service rendered on and after the date of this Order.

3. That the Schedule of Rates, attached as Appendix A, is hereby approved and deemed filed with the Commission pursuant to G.S. 62-138.

4. That the Notice to Customers, attached as Appendix B, shall be mailed with sufficient postage or hand delivered by MECO to all customers affected by the new rates no later than 10 days after the date of this Order; and that MECO shall submit to the Commission the attached Certificate of Service, properly signed and notarized, not later than 15 days after the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 4th day of May, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

APPENDIX A
PAGE 1 OF 2

SCHEDULE OF RATES

for

MECO UTILITIES, INC.

for providing water and sewer utility service in

MOBILE ESTATES MOBILE HOME PARK
Wake County, North Carolina

Monthly Metered Water Rates:

Base charge, zero usage	$ 14.03, minimum
Usage charge, per 1,000 gallons	$ 6.72

WATER AND SEWER – RATE INCREASE

Monthly Metered Sewer Rates:

Base charge, zero usage	$ 10.42, minimum
Usage charge, per 1,000 gallons	$ 12.69

Reconnection Charge:

If water utility service is cut off by utility for good cause (Rule 7-20), or	1/
If water utility service discontinued at customer request, or	1/
If sewer utility service discontinued for good cause (Rule R10-16e)	1/

1/ If reconnection is made during scheduled working hours	$15.00
If reconnection is made after-hours on normal workdays	$30.00
If reconnection is made in an emergency action on weekends or holidays	$30.00

Note: [Commission Rule R10-16(f): Whenever sewer service is discontinued for any reason, the utility shall send a report of termination of service to the local county board of health.]

Returned Check Fee:	$25.00
Bills Due:	On billing date
Bills Past Due:	15 days after billing date

Billing Frequency:	Shall be monthly in arrears
Finance Charge for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after the billing date.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-1166, Sub 17, on this the __4th__ day of May, 2018.

APPENDIX B

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

NOTICE TO CUSTOMERS
DOCKET NO. W-1166, SUB 17

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

Notice is hereby given that the North Carolina Utilities Commission has issued an Order granting an increase in rates and charges to MECO Utilities, Inc. (MECO), for providing water and sewer utility service in Mobile Estates Mobile Home Park in Wake County, North Carolina. The matter was scheduled for hearing subject to cancellation if significant protests were not received. The protest period has expired and no protests were received subsequent to customer notice. The hearing previously scheduled for March 22, 2018, was canceled by Commission Order issued March 12, 2018 and customer notice was provided.

The Commission has approved the following rates, effective for service rendered on and after the date of this Notice to Customers:

Monthly Metered Water Rates:	
Base charge, zero usage	\$ 14.03
Usage charge, per 1,000 gallons	\$ 6.72
Monthly Metered Sewer Rates:	
Base charge, zero usage	\$ 10.42
Usage charge, per 1,000 gallons	\$ 12.69

The approved rates will increase the average monthly combined water and sewer bill from \$84.17 to \$93.36, based on an average usage of 3,550 gallons.

Further, the Commission approved MECO's request to increase its returned check charge to \$25.00 and its disconnection/reconnection charge to \$15.00 when made during scheduled working hours and to \$30.00 when made during after-hours on normal workdays or in an emergency action on weekends or holidays.

ISSUED BY ORDER OF THE COMMISSION.
This the 4th day of May, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. W-71, SUB 12

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Ridgecrest Water Utility, Post Office Box 128, Ridgecrest, North Carolina 28770, for Authority to Increase Rates for Water Utility Service in its Ridgecrest Service Area in Buncombe County, North Carolina	)))))	ORDER GRANTING RATE INCREASE AND REQUIRING CUSTOMER NOTICE

BY THE COMMISSION: On October 30, 2017, Ridgecrest Water Utility (Ridgecrest or Applicant) filed an application with the Commission seeking authority to increase its rates and charges for water utility service in its Ridgecrest Service Area in Buncombe County, North Carolina. Ridgecrest serves approximately 314 water customers. The present water rates were established pursuant to the Commission's Recommended Order Granting Rate Increase and Requiring Customer Notice issued on December 22, 2015, in Docket No. W-71, Sub 11 (Sub 11 Proceeding), a general rate case proceeding.

By Order dated November 28, 2017, the Commission declared the proceeding to be a general rate case and suspended the proposed new rates for up to 270 days. By Order dated December 18, 2017, the Commission scheduled a public hearing for Thursday, March 29, 2018, in the Buncombe County Courthouse, Courtroom 1A, 60 Court Plaza, Asheville, North Carolina, subject to cancelation if no significant protests were received by February 2, 2018, subsequent to customer notice.

On February 13, 2018, the Company filed its certificate of service indicating that customer notice had been served as required by the December 18, 2017 Order.

The Commission received only one protest in response to the customer notice, which was filed on February 13, 2018. On February 16, 2018, the Public Staff filed a motion to cancel the previously scheduled hearing. By Order issued on February 23, 2018, the Commission canceled the hearing and directed the Applicant to notify its customers of the cancellation.

On March 9, 2018, the Applicant filed its certificate of service indicating that notice of cancellation of the hearing had been given as required by the February 23, 2018 Order.

On March 13, 2018, the Public Staff filed the affidavit and exhibits of Lindsay A. Quant, Utilities Engineer, Water, Sewer, and Communications Division, and the affidavit of June Chiu, Staff Accountant, Water/Communications Section, Accounting Division. In these affidavits, the Public Staff found the Applicant's proposed rates to be reasonable and recommended approval. Additionally, Public Staff witness Quant stated that the Applicant is providing adequate service to its customers. On March 15, 2018, the Public Staff filed Chiu Exhibit I, which was inadvertently omitted from the Affidavit of witness Chiu filed on March 13, 2018.

On April 5, 2018, the Public Staff filed a motion requesting that the Commission approve the rates that it had recommended. In its motion, the Public Staff represented that Ridgecrest has agreed with the Public Staff's recommendations. Further, the Public Staff's motion was accompanied by a proposed order.

On April 16, 2018, the Public Staff filed a Revised Chiu Exhibit I to replace Chiu Exhibit I that was filed on March 13, 2018. In its filing, the Public Staff stated that the revisions to Chiu Exhibit I were necessary to correct the Public Staff's adjustments related to state and federal income taxes, but did not otherwise affect the Public Staff's recommended revenue increase or rates for Ridgecrest.

Based upon the foregoing, the verified application, the affidavits and exhibits filed by the Public Staff, and the entire record in this matter, the Commission makes the following

FINDINGS OF FACT

1. Ridgecrest is a public utility pursuant to G.S. 62-2(23), is subject to the jurisdiction of the Commission, and is properly before the Commission seeking authority to increase its rates and charges for water utility service to its customers in Buncombe County, North Carolina.

2. The test period established for use in this proceeding is the 12-month period ended December 31, 2016.

3. The Applicant's present and proposed rates filed in its application are as follows:

	Present Rates	Proposed Rates
Residential Rates:		
Base charge, zero usage (bi-monthly minimum)	\$ 16.98	\$ 18.00
Usage charge, per 1,000 gallons	\$ 5.30	\$ 5.55

4. The Public Staff received one customer protest letter on January 1, 2018, which was filed with the Commission on February 13, 2018.

5. On average, Ridgecrest provides metered water utility service to approximately 305 residential water customers (Ridgecrest Community) and to the additional facilities at the Ridgecrest Conference Center (Conference Center). Water service to the Ridgecrest Community and the Conference Center is metered. The water system also provides unmetered service to the Conference Center camp areas.

6. The appropriate water system allocation factor for the Ridgecrest Community usage for purposes of this proceeding is 45.95%, with 54.05% allocated to the Conference Center and Conference Center camp areas.

7. The water system serving the Ridgecrest Service Area consists of 11 wells, two water treatment facilities with treatment equipment, three water storage tanks, a number of

pressure reducing valves to help regulate water pressure at different elevations, and distribution water mains. Ridgecrest's water system is generally in good condition and is adequately operated and maintained.

8. The Applicant is providing adequate service to its customers.

9. Ridgecrest's original cost rate base for water operations consists of the following components:

Plant in service	$1,290,890
Accumulated depreciation	(923,049)
Net plant in service	367,841
Residential allocation factor	45.95%
Net utility plant in service to residents	169,023
Contributions in aid of construction	(35,141)
Amortization of accumulated tap fees	19,098
Cash working capital	11,307
Average tax accruals	(455)
Original cost rate base	$ 163,832

10. The appropriate annual level of service revenues for use in this proceeding is $107,775 under the Applicant's present rates and $113,260 under the Applicant's proposed rates.

11. The Applicant requested an increase in rates that would produce $5,485 in additional service revenues, an increase of 5.09% over present annual service revenues.

12. It is reasonable and appropriate to include total rate case costs of $503 related to this rate case proceeding and the unamortized balance of the Sub 11 Proceeding in the amount of $259, amortized over three years, resulting in annual rate case expense of $254.

13. The appropriate level of operations and maintenance expenses for use in this proceeding is $90,458.

14. The appropriate level of depreciation and amortization expense for use in this proceeding is $12;517.

15. The appropriate level of other taxes for use in this proceeding is $2,437.

16. It is reasonable and appropriate to calculate regulatory fees using the statutory rate of 0.14%.

17. Ridgecrest is a not-for-profit entity and does not have state or federal income taxes included in its water rates.

18. The appropriate level of total operating revenue deductions under present rates for use in this proceeding is $105,404. Operating revenue deductions requiring a return, exclusive of regulatory fee, amount to $105,252.

19. Pursuant to G.S. 62-133, the rate base method is the appropriate method for determining the Applicant's revenue requirement for water operations in this proceeding.

20. The rates proposed by the Applicant in this proceeding will produce an overall return of 5.32% on rate base. This return is not in excess of a reasonable level, and accordingly, the proposed rates are reasonable.

21. Based on the Public Staff's investigation, the Public Staff recommended that the applied for increase in service revenues of $5,485, or 5.09%, is justified.

22. The rates requested by Ridgecrest and recommended by the Public Staff are just and reasonable and should be approved.

23. The Applicant's proposed water rates shown below and provided in Appendix A, attached hereto, are just and reasonable and should be approved.

Residential Rates:	
Base charge, zero usage	
(bi-monthly minimum)	$ 18.00
Usage charge, per 1,000 gallons	$ 5.55

24. Ridgecrest should be allowed to increase its rates and charges so as to produce total annual operating revenues of $114,120, comprised of $113,260 in service revenues, $2,284 in miscellaneous revenues, and bad debt expense of ($1,424).

25. The Applicant's request to increase its returned check charge from $10.00 to $15.00 is reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 THROUGH 3

The evidence supporting these findings of fact is contained in the Commission's records, the verified application, and the affidavits of Accountant Chiu and Engineer Quant. These findings are primarily jurisdictional and informational and are uncontested.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4 THROUGH 8

The evidence supporting these findings of fact is contained in the affidavit of Engineer Quant and in the Commission's records.

Engineer Quant stated that her investigation of Ridgecrest's rate case application included a field inspection, review of the Applicant's records, review of customer complaints, review of records from the North Carolina Division of Environmental Quality (NCDEQ), and the gathering of information from other sources.

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Engineer Quant observed that as a result of the customer notice, the Public Staff received one customer complaint. She commented that such complaint concerned the frequency of another rate increase and also addressed a service-related issue concerning a lack of customer service support during a particular outage incident. Engineer Quant contacted both Ridgecrest and the customer to discuss the complaint.

Engineer Quant noted that Ridgecrest provides metered water utility service to the Ridgecrest Community, consisting of approximately 305 water customers, and to the additional facilities at the Conference Center. Further, she commented that the water system also provides unmetered service to the Conference Center camp areas. Engineer Quant maintained that the original water system's installation/configuration is such that the facilities are scattered throughout the camp and the locations of the distribution mains are not known; as a result, she opined that it is not realistic to meter the camping facilities.

Further, Engineer Quant stated that the overall number of water utility customers fluctuates seasonally. She observed that, although the number of customers rises in the summer months and during the winter holiday seasons, Ridgecrest has not reported significant customer growth. Engineer Quant contended that due to the varying number of customers throughout the year, the average customer count of 305 customers was utilized in her rate analysis for this proceeding.

With respect to the water system allocation factor to the Ridgecrest Community, Engineer Quant stated that Ridgecrest originally calculated a factor of 46.06%. The Public Staff determined and the Applicant acknowledged that the consumption data was miscalculated. Engineer Quant stated that based upon the updated, corrected consumption data, the appropriate water system allocation factor was 45.95% for the Ridgecrest Community usage.

Engineer Quant inspected the Ridgecrest water system on February 28, 2018, with Mr. Daniel Redding, Facilities Manager for Ridgecrest and Mr. Raymond Sylvestre, Water Plant Operator. She described the water system as consisting of 11 wells, two water treatment facilities with treatment equipment, three water storage tanks, a number of pressure reducing valves to help regulate water pressure at different elevations, and distribution water mains. She noted that an interconnection with the Town of Black Mountain water system provides an emergency backup water supply. She commented that sewer utility service for the Ridgecrest Service Area is provided by the Metropolitan Sewerage District of Buncombe County (MSD).[1]

Further, Engineer Quant reviewed NCDEQ records and discussed the operation of the water system with Ms. Kimberly Barnett of the Asheville Regional Office of the Public Water Supply Section (PWSS). She commented that Ms. Barnett conducted a sanitary survey of the water system on April 14, 2016, and Ms. Barnett concluded that "[o]verall the system was in good working order with no major deficiencies noted on the date of the survey".

[1] Per Engineer Quant, an estimate of water/sewer usage for the Conference Center camp areas is based on NCDEQ wastewater flow design rates for camps of 60 gallons per person per day.

Further, Engineer Quant maintained that the water system is up to date on sampling and monitoring with the exception of Disinfection By Products sampling in the last quarter of 2017. She noted that Ridgecrest is required to provide public notice in 2018 to return to compliance.

Engineer Quant concluded that, based upon the Public Staff's investigation, the information provided by the Applicant and NCDEQ, and the lack of significant customer complaints, the Applicant is providing adequate service to its customers. Therefore, the Commission finds and concludes that the quality of water utility service provided by the Applicant to its customers is adequate.

Moreover, with respect to the water system allocation factor, the Commission finds and concludes that a water system allocation factor for the Ridgecrest Community usage of 45.95% recommended by the Public Staff based upon the revised consumption data provided by the Applicant is reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence supporting this finding of fact is contained in the Commission's records, the verified application, and in the affidavit and exhibit of Accountant Chiu.

The adjustments made by the Public Staff to the Applicant's original cost rate base included adjustments to plant in service, accumulated depreciation, contributions in aid of construction, amortization of accumulated tap fees, cash working capital, and average tax accruals.

Accountant Chiu observed that the total amount for plant in service included on the application did not agree to the amount that was approved by the Commission in the Sub 11 Proceeding. She calculated an amount for plant in service beginning with the amount approved by the Commission in the Sub 11 Proceeding and to that amount, she included the additional plant items capitalized since that rate case. Based on the recommendation of Engineer Quant, she capitalized $5,030 for motors for Well #4 and Well #13 and $4,900 for a pump and control box for Well #10.

Accountant Chiu explained that the amount of accumulated depreciation recommended by the Public Staff in this proceeding was calculated based on the year each plant asset was placed in service and the number of years in service, using the half-year convention in the first year of an asset's depreciable life. Further, Accountant Chiu stated that the Public Staff included one-eighth of operating expenses in original cost rate base as a measure of cash working capital which provides the Applicant with the funds necessary to carry on the day-to-day operations of the water utility business.

The adjustments made by Accountant Chiu to the various components of original cost rate base resulted in an amount of $163,832 for original cost rate base for use in this proceeding. The Applicant did not contest the Public Staff's adjustments to original cost rate base.

Based upon the foregoing, the Commission finds and concludes that the appropriate level of original cost rate base for use in this proceeding is $163,832.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10 AND 11

The evidence supporting these findings of fact is contained in the Commission's records, the verified application, the affidavit and exhibits of Engineer Quant, and the affidavit and exhibit of Accountant Chiu.

Engineer Quant calculated annual water service revenues of $107,775 under the currently approved rates and $113,260 under the Applicant's proposed rates. According to the Public Staff's calculations, the Applicant's requested rates in this proceeding produce $5,485 in additional annual service revenues. The Applicant did not contest the Public Staff's calculations of water service revenues.

Based upon the foregoing, the Commission finds and concludes that the appropriate levels of annual service revenues at present and proposed rates for use in this proceeding are $107,775, and $113,260, respectively.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12 AND 13

The evidence supporting these findings of fact is contained in the Commission's records, the affidavit and exhibits of Engineer Quant, and the affidavit and exhibit of Accountant Chiu. The following table summarizes the amounts that the Public Staff recommended for inclusion in determining the proper level of total O&M expenses for use in this proceeding:

Item	Amount
Salaries and wages	$62,281
Administrative and office	7,004
Maintenance and repairs	7,733
Transportation	166
Electric power	10,191
Testing	939
Item	Amount
Chemicals	1,432
Permit fees and licenses	372
Purchased water treatment	16
Rate case expense	254
Miscellaneous	70
Total O&M expenses	$90,458

The Public Staff made adjustments to the levels of administrative and office, maintenance and repairs, electric power, chemicals, testing, transportation, and permit fees based upon recommendations by Engineer Quant. Accountant Chiu stated that the Applicant did not include an amount for rate case expense in its application. Accountant Chiu explained that she calculated an amount of rate case expense for this proceeding based upon the cost of the filing fee and the costs for copying and mailing notices to customers. She also calculated an amount of $259 of unamortized rate case expense from the Sub 11 Proceeding. Accountant Chiu recommended that the combined rate case costs of $762 related to costs of this proceeding and the unamortized balance of the Sub 11 Proceeding be amortized over three years resulting in annual rate case expense of $254.

The Applicant did not contest the Public Staff's adjustments to its O&M expenses.

Based upon the foregoing, the Commission finds and concludes that the appropriate level of O&M expenses for use in this proceeding is $90,458.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 14 THROUGH 17

The evidence supporting these findings of fact is contained in the Commission's records, the affidavit of Engineer Quant, and the affidavit and exhibit of Accountant Chiu. The following table summarizes the amounts that the Public Staff recommended for inclusion in determining the proper level of total ongoing depreciation and amortization expense, regulatory fees, and taxes for use in this proceeding:

Item	Amount
Depreciation expense	$13,922
Amortization expense	(1,405)
Property taxes	0
Payroll taxes	2,277
Regulatory fees	160
State income taxes	0
Federal income taxes	0
Total depreciation and taxes	$14,954

The Public Staff made adjustments to the levels of depreciation and amortization expense, payroll taxes, and regulatory fees. Further, Accountant Chiu reclassified the amount of permit fees inadvertently recorded to gross receipts tax to O&M expenses. The Applicant did not contest the Public Staff's adjustments to depreciation and amortization expense, regulatory fees, and taxes.

Based upon the foregoing, the Commission finds and concludes that the appropriate level of depreciation and amortization expense, regulatory fees, and payroll taxes for use in this proceeding is $14,954.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 18 THROUGH 24

The evidence supporting these findings of fact is contained in the Commission's records, the verified application, the affidavit and exhibits of Engineer Quant, and the affidavit and exhibit of Accountant Chiu.

Accountant Chiu stated that based upon her investigation, the Applicant's original cost rate base at December 31, 2016, is $163,832 and the level of operating revenue deductions requiring a return (total operating expenses excluding regulatory fees and income taxes) is $105,252. Accountant Chiu stated that pursuant to G.S. 62-133, she used the rate base method to evaluate the Applicant's proposed revenue requirement. Accountant Chiu stated that the Applicant's proposed revenues are not unreasonable and would not be unfair to customers. She recommended that water rates be set to reflect the $5,485 increase requested by the Applicant, for an annual level of total operating revenues of $114,120.

Further, Engineer Quant concluded that, based upon her investigation, the rates requested by the Applicant are justified and should be approved.

Based upon the foregoing, the Commission finds and concludes that the rate base method is the appropriate method for evaluating the Applicant's proposed revenue requirement and that the monthly rates for water utility service requested by the Applicant and recommended by the Public Staff are just and reasonable and should be approved. Consequently, the Commission finds and concludes that Ridgecrest Water Utility should be allowed to increase its rates and charges so as to produce total annual operating revenues of $114,120.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 25

The evidence supporting this finding of fact is contained in the Commission's records, the verified application, and the affidavit of Engineer Quant.

In its application, Ridgecrest requested approval to increase the returned check charge from $10.00 to $15.00. Engineer Quant recommended approval of the Applicant's proposed returned check charge.

Therefore, the Commission finds and concludes that the Applicant's request to increase its returned check charge from $10.00 to $15.00, is just and reasonable and should be approved.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

Based upon all the evidence including the Public Staff's recommendations, the Commission finds and concludes that the Applicant has sufficiently demonstrated the need to increase its rates for providing water utility service. Therefore, the Commission concludes that the rates proposed by the Applicant and recommended by the Public Staff are just and reasonable and should be approved. Further, the Commission finds and concludes that the Applicant's request to increase its returned check charge to $15.00 is reasonable and should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That the application for rate increase filed by Ridgecrest Water Utility on October 30, 2017, and the affidavits and exhibits of Public Staff witnesses Lindsay A. Quant, Utilities Engineer, Water, Sewer, and Communications Division, and June Chiu, Staff Accountant, Water/Communications Section, Accounting Division filed by the Public Staff on March 13, 2018 and March 15, 2018, in this docket are hereby received as evidence.

2. That Ridgecrest Water Utility is authorized to increase its rates for water utility service in its Ridgecrest Service Area in Buncombe County, North Carolina, as reflected in the Schedule of Rates, attached hereto as Appendix A. These rates shall be effective for service rendered on and after the date of this Order.

3. That the Schedule of Rates, attached hereto as Appendix A, is hereby approved and deemed filed with the Commission pursuant to G.S. 62-138.

4. That a copy of the Notice to Customers, attached hereto as Appendix B, shall be mailed or hand delivered to all customers of the Applicant within 15 days of the date of this Order, and that the Applicant shall submit to the Commission the attached Certificate of Service, properly signed and notarized, not later than 30 days after the issuance date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 25th day of April, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

APPENDIX A

SCHEDULE OF RATES

for
RIDGECREST WATER UTILITY
for providing water utility service to its customers in

RIDGECREST SERVICE AREA
Buncombe County, North Carolina

Bi-Monthly Residential Rates:	
Base charge, zero usage	\$18.00
Usage charge, per 1,000 gallons	\$ 5.55
Tap Fee:	Actual Cost
Reconnection Fee/Change of Service Fee:	\$25.00
Returned Check Fee:	\$15.00
Bills Due:	On billing date
Bills Past Due:	25 days after billing date
Billing Frequency:	Bi-monthly for service in arrears

Finance Charge for Late Payment:	1.0% per month will be applied to the unpaid balance of all bills still past due 25 days after the billing date

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-71, Sub 12, on this the 25th day of April, 2018.

APPENDIX B

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

NOTICE TO CUSTOMERS

DOCKET NO. W-71, SUB 12

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

Notice is hereby given that the North Carolina Utilities Commission has issued an Order granting an increase in rates to Ridgecrest Water Utility (Ridgecrest). The Order approved the following rates for water utility service provided in Ridgecrest Service Area on and after the date of this Notice:

Residential Rates:

Base charge, zero usage (bi-monthly minimum)	$ 18.00
Usage charge, per 1,000 gallons	$ 5.55

Based upon the average bi-monthly customer consumption of 8,000 gallons, the average bi-monthly water bill will increase from $59.38 to $62.40, or 5.09%.

Further, the Commission approved Ridgecrest's request to increase its returned check charge from $10.00 to $15.00.

This the 25th day of April, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Linnetta Threatt, Deputy Clerk

WATER AND SEWER – RATE INCREASE

CERTIFICATE OF SERVICE

I, ______________________________________, mailed with sufficient postage or hand delivered to all affected customers the attached Notice to Customers issued by the North Carolina Utilities Commission in Docket No. W-71, Sub 12, and the Notice was mailed or hand delivered by the date specified in the Order.

This the ___ day of __________________, 2018.

By: ________________________________
Signature

____
Name of Utility Company

The above named Applicant, ______________________________, personally appeared before me this day and, being first duly sworn, says that the required Notice to Customers was mailed or hand delivered to all affected customers, as required by the Commission Order dated ___________________ in Docket No. W-71, Sub 12.

Witness my hand and notarial seal, this the ___ day of ___________, 2018.

____
Notary Public

____
Printed Name

(SEAL) My Commission Expires: ________________________________
Date

WATER AND SEWER – RATE INCREASE

DOCKET NO. W-1034, SUB 8

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Water Resources, Inc.,	)	
5970 Fairview Road, Suite 710,	)	
Charlotte, North Carolina 28210, for	)	RECOMMENDED ORDER
Utility Service in Rocky River Plantation	)	APPROVING AGREED UPON
Subdivision in Cabarrus County and	)	RATES AND REQUIRING
River Walk Subdivision in Mecklenburg	)	CUSTOMER NOTICE
County, North Carolina	)	

HEARD: Thursday, September 20, 2018, at 7:00 p.m. in the Mecklenburg County Courthouse, 832 E. 4th Street, Courtroom 5350, Charlotte, North Carolina

BEFORE: Lemuel Hinton, Hearing Examiner

APPEARANCES:

For Water Resources, Inc.:

No counsel of record

For the Using and Consuming Public:

John D. Little, Staff Attorney
Public Staff – North Carolina Utilities Commission
4326 Mail Service Center
Raleigh, North Carolina 27699-4300

HINTON, HEARING EXAMINER: On April 18, 2018, Water Resources, Inc. (WRI or Company) filed an application with the Commission seeking authority to increase its rates for water utility service in Rocky River Plantation Subdivision (Rocky River) in Cabarrus County and River Walk Subdivision (River Walk) in Mecklenburg County, North Carolina.

By Order dated May 14, 2018, the Commission declared this docket to be a general rate case, suspended the Company's proposed rates, scheduled a hearing, and required customer notice.

WRI filed the Commission-required Certificate of Service on February 20, 2018, indicating that the Company provided the Notice to Customers in compliance with the May 14 Order.

On August 29, 2018, the Public Staff filed its direct testimony of witnesses June Chiu and David C. Furr and the Affidavit of Bob R. Hinton.

Subsequent to the filing of WRI's Application in this docket, the Public Staff engaged in substantial discovery of WRI regarding the matters addressed by the Company's Application and further examined the relevant books and records of WRI with respect to its Application. The Public Staff also conducted field inspections of the water systems at Rocky River and River Walk.

Six Consumer Statements of Position were filed on September 12, 2018. The issues in these statements concern the magnitude of the requested rate increase, customer service, and water quality.

On September 20, 2018, a hearing was held at the Mecklenburg County Courthouse in Mecklenburg County, Charlotte, North Carolina. No members of the public or WRI customers were present. The Company offered the testimony of Dennis Abbott, and the Public Staff offered the testimony of David C. Furr. The testimony and exhibits of June Chiu, David C. Furr, and the affidavit of Bob R. Hinton were received in evidence at the Public Staff's request.

The Public Staff indicated the correct rates and charges are contained in Public Staff Witness Furr's Exhibit 8 to his Pre-Filed Direct Testimony. The Public Staff also indicated that Public Staff's Witness Furr's summary of the agreed upon rates and charges at the September 20, 2018 hearing were not correct.

Based on the foregoing, the verified Application, the testimony and exhibits presented at the hearing, and the entire record in this proceeding, the Hearing Examiner makes the following:

FINDINGS OF FACT

1. WRI is a corporation duly organized under the law and is authorized to do business in the State of North Carolina. The Company is subject to the regulatory oversight of this Commission.

2. WRI is properly before the Commission pursuant to N.C. Gen. Stat. § 62-1 et seq. seeking a determination of the justness and reasonableness of its proposed rates and charges for its water utility operations.

3. As of December 31, 2017, WRI served 114 water customers at Rocky River in Cabarrus County, and 32 water customers at River Walk in Mecklenburg County.

4. The Company's existing and proposed rates are as follows:

	Proposed Rates	Present Rates
Rocky River		
Monthly Metered Water Rates:		
Base charge, zero usage	$ 9.28	$11.20
Usage charge, per 1,000 gallons	$ 2.57	$ 3.10

WATER AND SEWER – RATE INCREASE

River Walk

Monthly Metered Water Rates:		
Base charge, zero usage	$37.6	$40.68
Usage charge, per 1,000 gallons	$ 9.42	$10.18

5. The test period in this proceeding is the 12 months ending December 31, 2017.

6. Neither water system is in compliance with North Carolina Department of Environmental Quality (DEQ) regulations.

7. A sanitary survey for Rocky River was conducted by DEQ on March 29, 2018, and WRI was sent a Notice of Deficiency letter, dated April 3, 2018. The stated deadlines for resolving the issues was July 31, 2018, and further extended to July 31, 2018. As of August 16, 2018, the following items were not resolved:

a. The hypochlorite solution injection point is not in the location shown on the approved plans for the chemical feed system improvements, which violates the requirements of 15A NCAC 18C.1304(a);

b. A faucet or spigot for sampling treated water prior to delivery to the first customer was not provided, which violates the requirements of 15A NCAC 18C.0402(e);

c. The well house provided for Well 1 was not secured with a lock and key, which violates the requirements of 15A NCAC 18C.0402(f);

d. Totalizing meters for Well 1 and Well 2 were not functional, which violates the requirements of 15A NCAC 18C.0402(g)(6); and

e. Approximately three residual disinfection tests in the distribution system are performed per week. The water system is classified as a B Distribution system, which requires a minimum of five residual disinfection tests to be performed in the distribution system per week. This is a violation of the requirements of 15A NCAC 18C.1302(a)(1)(A).

8. The DEQ Notice of Deficiency letter, dated April 3, 2018, also made the following recommendations:

a. Due to the results from the iron and manganese field readings occasionally exceeding the secondary maximum contaminant levels, it is recommended that the water filter be evaluated by a qualified professional to assess the operation and maintenance of the water filter;

b. That the Hach Iron and Manganese Color Disc Test Kit used to measure the iron and manganese concentrations reported on the monthly operation reports, be calibrated in accordance with the manufacturer's instructions, that no expired reagents are used, and that the test kit be stored and maintained in accordance with the manufacturer's instructions;

c. That the elevated storage tank be regularly inspected by a qualified professional and that the vent be inspected on a regular basis to ensure that the screen in intact; and

d. That the holes observed in the lower portion of the western wall of the building containing the filter be repaired.

9. Water meters at Rocky River are over 25 years old, and the Public Staff has recommended that they be replaced.

10. Cases of cloudy water due to suspended air, and brown water due to high iron content have been observed at Rocky River, and WRI should take steps to better monitor water quality.

11. A sanitary survey for River Walk was conducted by DEQ on December 6, 2017, and WRI was sent a Notice of Deficiency letter, dated January 2, 2018. The stated deadlines for resolving issues was extended to May 2, 2018. As of August 16, 2018, the following items were not resolved:

a. The cover over the well holes for Well 1 was not secured against unauthorized access, and a locking mechanism was not provided, which violates the requirements of 15A NCAC 18C.0405(f);

b. A properly sized vacuum relief valve is not provided for the hydropneumatic tank, which violates the requirements of 15A NCAC 18C.0405(c)(3); and

c. The Department of Labor inspection for the hydropneumatic tank is expired, which violates the requirements of 15A NCAC 18C.0405(c)(5).

12. The DEQ Notice of Deficiency letter, dated January 2, 2018, also made the following recommendations:

a. To achieve a proper free chlorine residual in the water system, that the drop pipe, tubing, and injection point associated with the hypochlorite treatment equipment be cleaned or replace as necessary to ensure the proper flow of chemicals. If the Operator Responsible Charge is unable to increase the sodium hypochlorite feed rate after the corrective actions have been taken, that further investigation into the issue be performed until a solution can be identified and implemented;

b. That the leaking Well 1 blow-off valve be repaired or replaced;

c. That the hydropneumatic tank and ground storage tank be either replaced or cleaned and recoated by a qualified professional;

d. That trees and limbs surrounding both well houses and water tanks be trimmed as necessary to ensure that no water system components would be damaged in the event of falling trees and limbs; and

e. That bacteria sampling sites be rotated on a monthly basis and that bacteria sample siting plan be developed.

13. Insulation in the River Walk water treatment building needs to be properly installed.

14. WRI should investigate any possible operational issues that may be causing high power expenses.

15. WRI's customer service and communications needs to improve.

16. WRI should keep a log of customer complaints. The log should include the date and time the customer contacted WRI or its answering service, a description of the complaint, what was done to resolve the issue, and the date and time that resolution of the issue was communicated back to the customer. A copy of these records should be filed in this docket on a quarterly basis until further order of the Commission.

17. WRI should return customer calls within 60 minutes of receipt, and document this in the log book of customer complaints.

18. WRI should respond to outages within 60 minutes of receiving an outage report from a customer, and document this in the log book of customer complaints.

19. The original cost rate base for use in this proceeding for Rocky River is ($1,176), consisting of plant in service of $77,743, plus cash working capital of $6,498, less accumulated depreciation of $71,546, contributions in aid of construction of $13,295, and average tax accruals of $576.

20. The original cost rate base for use in this proceeding for River Walk is $21,851, consisting of plant in service of $33,633, plus cash working capital of $3,438, less accumulated depreciation of $15,023, contributions in aid of construction of $0, and average tax accruals of $197.

21. The appropriate level of total revenues for use in this proceeding for Rocky River is $32,084 under the Company's present rates and $38,862 under the proposed rates.

22. The appropriate level of total revenues for use in this proceeding for River Walk is $33,366 under the Company's present rates and $36,055 under the proposed rates.

23. The appropriate level of operating revenue deductions for Rocky River under present rates for use in this proceeding is $56,026. Operating revenue deductions exclusive of regulatory fee and income taxes amount to $55,981.

24. The appropriate level of operating revenue deductions for River Walk under present rates for use in this proceeding is $30,551. Operating revenue deductions exclusive of regulatory fee and income taxes amount to $29,646.

25. It is reasonable and appropriate to determine the revenue requirement for WRI water rates using the operating ratio methodology as allowed by N.C. Gen. Stat. § 62-133.1.

26. A margin of 7.5% on operating revenue deductions requiring a return is appropriate for use in this proceeding.

27. WRI's present and proposed service revenues for the 12-month period ending December 31, 2017 are as follows:

	Present	Proposed
Rocky River	$32,829	$39,607
River Walk	$33,468	$36,157

28. The revenues generated by the Company's proposed water rates for Rocky River are not unreasonable and would not be unfair to its customers.

29. The annual service revenue requirement for River Walk necessary to allow the Company the opportunity to earn the 7.5% return found just and reasonable is $32,696, which is a decrease of $773 from the service revenues at present rates.

30. The following rates will produce the annual level of revenues approved herein for water operations at River Walk:

Base Charge, zero usage	$37.50
Usage charge, per 1,000 gallons	$ 9.07

31. WRI agrees with the Public Staff's rates and recommendations.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT 1-5

(Background Information)

These findings of fact are essentially informational, procedural, and jurisdictional in nature, and the matters which they involve are for the most part uncontroversial. They are supported by information contained in the verified Application, the affidavit and testimony and Exhibits of the Public Staff's witnesses and Company witness Abbott, and the Commission files and records regarding this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT 6-18

(Violations of Water Systems Regulations and Recommendations)

These findings of fact are found in the testimony and exhibits of Public Staff witness Furr, and are uncontested by WRI. At the hearing held on September 20, 2018, Company witness Abbott did not contest any of the findings, and agreed to the Public Staff recommendations.

The Hearing Examiner agrees with the Public Staff's observations and recommendations. WRI needs to take the operation of its water systems seriously and devote considerably more attention to them than it has in the past. WRI should be ordered to take the corrective measures recommended by Public Staff witness Furr. WRI should be aware that if these corrective measures are not implemented, the Commission has the authority to impose substantial penalties.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT 19-25

(Original Cost Rate Base, Total Revenue, Operating Revenue, Revenue Requirement)

These findings of fact are based on the testimony and exhibits of Public Staff witness Chiu. WRI did not take issue with the Public Staff's position on these issues.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT 26

(7.5% Operating Margin)

This finding of fact is based on the affidavit of Public Staff witness Bob Hinton, and the testimony and exhibits of Public Staff witness Chiu. WRI did not take issue with the Public Staff's position on this issue.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT 27

(Proposed Service Revenues)

This finding of fact is based on the testimony and exhibits of Public Staff witnesses Furr and Chiu, and are uncontested by WRI.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT 28-29

(Annual Service Revenue)

These findings of fact are based on the testimony and exhibits of Public Staff witness Chiu, and are uncontested by WRI.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT 30

(Rate Recommendation)

This finding of fact is based on the testimony and exhibits of Public Staff witness Furr. Although Public Staff witness Furr's Pre-filed Direct Testimony and his summary of the proposed rates were not accurate, the correct rates are contained in Public Staff witness Furr's Exhibit 8.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT 31

(Agreement of Public Staff and WRI to Recommended Rates)

This finding of fact is based on the testimony and exhibits of the Public Staff's witnesses and Company witness Abbott.

IT IS, THEREFORE, ORDERED as follows:

1. That the Schedules of Rates, attached hereto as Appendix A and B, are hereby approved and deemed to be filed with the Commission pursuant to N.C. Gen. Stat §. 62-138;

2. That the Schedules of Rates, attached hereto as Appendix A and B, are hereby authorized to become effective for service rendered on and after the effective date of this Order;

3. That the Notice to Customers, attached hereto as Appendix C, shall be mailed with sufficient postage or hand delivered to all affected customers in conjunction with WRIs next regularly scheduled billing process;

4. That WRI shall file the attached Certificate of Service, properly signed and notarized, not later than 10 days after the Notice to Customers is mailed or hand delivered to customers;

5. That WRI correct the deficiencies stated in findings of fact 7 and 11 within 90 days of the date of this order;

6. That WRI complete the recommendations identified in findings of fact 8, 9, and 12, within 6 months of the date of this order;

7. That WRI investigate any possible operational issues that may be causing high power expenses at River Walk;

8. That WRI shall file a report with the Commission within 90 days after the date this Recommended Order becomes final and effective; showing that the requirements of ordering paragraphs 5 above have been completed;

9. That WRI shall file a report with the Commission within 6 months after the date this Recommended Order becomes final and effective, showing that the recommendations of ordering paragraph 6 above have been completed;

10. That WRI keep a log of customer complaints. The log shall include the date and time the customer contacted WRI or its answering service, a description of the complaint, what was done to resolve the issue, and the date and time that resolution of the issue was communicated back to the customer. A copy of these records shall be filed in this docket on a quarterly basis until further order of the Commission;

11. That WRI return customer calls within 60 minutes of receipt, and document this in the log book of customer complaints; and

12. That WRI respond to outages within 60 minutes of receiving an outage report from a customer, and document this in the log book of customer complaints.

ISSUED BY ORDER OF THE COMMISSION.
This the 21st day of November, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

APPENDIX A

SCHEDULE OF RATES

for

WATER RESOURCES, INC.

for providing water utility service in

ROCKY RIVER PLANTATION SUBDIVISION

Cabarrus County, North Carolina

Monthly Metered Residential Water Rates:	
Base Charge, zero usage	$ 11.20
Usage Charge, per 1,000 gallons	$ 3.10
Tap on Fee:	None
Reconnection Charges:	
If water service cut off by utility for good cause	$ 23.92
If water service discontinued at customer's request	$ 23.92

Bills Due:	On billing date
Bills Past Due:	20 days after billing date
Billing Frequency:	Shall be monthly for service in arrears
Finance Charge for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-1034, Sub 8, on this the 21st day of November, 2018.

WATER AND SEWER – RATE INCREASE

APPENDIX B
PAGE 1 OF 2

SCHEDULE OF RATES
for
WATER RESOURCES, INC.
for providing water utility service in

RIVER WALK SUBDIVISION

Mecklenburg County, North Carolina

Monthly Metered Water Utility Service Rates:	
Base charge, zero usage	$ 37.50
Usage charge, per 1,000 gallons	$ 9.07
Connection Charge: (New Residential Connection Only)	$685.00
New Account Fee:	$ 40.00
Reconnection Charge:	
If water service is cut off by utility for good cause:	$ 40.00
If water service cut off by utility at customer's request:	$ 40.00
Billing rates per hour for after hours, holidays, weekends	$ 40.00

If payment for water utility service is not received by the past-due date, a customer may, in addition to all past-due and current charges, have to pay late payment finance charges to avoid having water utility service disconnected.

To resume water utility service after discontinuance for good cause, a customer must pay the reconnection charge(s) discussed above, plus any delinquent water bill(s), including finance charges.

APPENDIX B
PAGE 2 OF 2

Returned Check Charge:	$25.00
Billing Frequency:	Shall be monthly for service in arrears
Bills Due:	On billing date
Bills Past Due:	15 days after billing date
Finance Charges for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after the billing date.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-1034, Sub 8, on this the 21st day of November, 2018.

WATER AND SEWER – RATE INCREASE

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

NOTICE TO CUSTOMERS
DOCKET NO. W-1034, SUB 8
BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

Notice is given that the North Carolina Utilities Commission has issued an Order making changes in rates for Water Resources, Inc. The Order approved a rate increase for Rocky River Plantation Subdivision in Cabarrus Count, and a decrease in rates for River Walk Subdivision in Mecklenburg County. The following rates for water utility service provided on and after the date of this notice.

Rocky River Planation Monthly Metered Water Rates:

Base Charge, zero usage	\$ 11.20
Usage Charge, per 1,000 gallons	\$ 3.10

River Walk Monthly Metered Water Rates:

Base Charge, zero usage	\$ 37.50
Usage Charge, per 1,000 gallons	\$ 9.07

The Commission also ordered Water Resources, Inc., to make numerous improvements to the water systems, and steps to improve water quality and customer service.

This the 21st day of November, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

WATER AND SEWER – RATE INCREASE

CERTIFICATE OF SERVICE

I, ___________________________________, mailed with sufficient postage or hand delivered to all affected customers the attached Notice to Customers issued by the North Carolina Utilities Commission in Docket No. W-1034, Sub 8, and the Notice was mailed or hand delivered by the date specified in the Order.

This the _____ day of ___________________, 2018.

By: _________________________
Signature

____
Name of Utility Company

The above named Applicant, ______________________________, personally appeared before me this day and, being first duly sworn, says that the required Notice to Customers was mailed or hand delivered to all affected customers, as required by the Commission Order dated ____________________ in Docket No. W-1034, Sub 8.

Witness my hand and notarial seal, this the ___ day of _______________, 2018.

____
Notary Public

____
Printed Name

(SEAL) My Commission Expires: _________________________
Date

DOCKET NO. W-933, SUB 11

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Etowah Sewer Company, Inc., Post Office Box 1659, Etowah, North Carolina 28729, for Transfer of the Sewer Utility System Serving Etowah in Henderson County, North Carolina, to the City of Hendersonville (Exempt From Regulation)	))))))	ORDER RESCINDING COMMISSION'S ORDER APPROVING TRANSFER TO OWNER EXEMPT AND REQUIRING CUSTOMER NOTICE

BY THE COMMISSION: On July 21, 2016, Etowah Sewer Company, Inc. (Etowah), and the City of Hendersonville, North Carolina (Hendersonville), filed an application with the Commission seeking authority to transfer Etowah's sewer utility service serving the unincorporated community of Etowah in Henderson County, North Carolina, to Hendersonville, which is exempt from Commission regulation. Attached to the application was a purchase agreement under which Hendersonville had agreed to purchase the Etowah sewer system for $1,026,000. Etowah currently provides sewer utility service to approximately 375 residential customers and 42 commercial customers in the unincorporated community of Etowah in Henderson County. Hendersonville provides water utility service to this service area.

On November 22, 2016, the Commission issued an Order Approving Transfer to Owner Exempt, Canceling Franchise, Releasing Bond, and Requiring Customer Notice (Order Approving Transfer). The Order Approving Transfer authorized Etowah to transfer its sewer utility system to Hendersonville, required Etowah to provide written notification to the Commission within five days after the closing of the transfer of the sewer system was completed, allowed the cancellation of the franchise granted to Etowah in Docket No. W-933, Sub 0, effective on the date Etowah filed with the Commission written notification that the closing of the transfer of the sewer system had been completed, allowed the release of the $20,000 bond and surety held by the Commission to Etowah upon receipt of written notification to the Commission that closing of the transfer of the sewer system had been completed, and required customer notice. Certificates of Service were filed by both Etowah and Hendersonville.

On March 2, 2018, Etowah filed a letter with the Commission requesting that the Order Approving Transfer be rescinded. In its letter, Etowah stated that after completion of negotiations with Hendersonville, it learned of an inter-local agreement between Hendersonville and Henderson County, which required County approval prior to Hendersonville providing sewer utility service within the County. At the regular County Board of Commission's meeting on July 19, 2017, the County voted against the project. Etowah indicated that as a result, the sale of the system will not take place.

On March 26, 2018, the Public Staff presented the matter at the Commission's Staff Conference and recommended that the Order Approving Transfer be rescinded, and that customers be notified.

Based on the foregoing, the Commission is of the opinion that the Order Approving Transfer should be rescinded and that customers should be notified.

IT IS, THEREFORE, ORDERED as follows:

1. That the Order Approving Transfer to Owner Exempt, Canceling Franchise, Releasing Bond, and Requiring Customer Notice, issued on November 22, 2016, is hereby rescinded effective the date of this Order.

2. That a copy of this Order shall be mailed with sufficient postage or hand delivered by Etowah to all customers affected no later than 10 days after the date of this Order; and that Etowah shall submit to the Commission the attached Certificate of Service, properly signed and notarized, not later than 15 days after the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the __26th__ day of March, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

CERTIFICATE OF SERVICE

I, ________________________________, mailed with sufficient postage or hand delivered to all affected customers a copy of the Order issued by the North Carolina Utilities Commission in Docket No. W-933, Sub 11, and such Order was mailed or hand delivered by the date specified in the Order.

This the _____ day of ____________________, 2018.

By: ____________________________
Signature

____
Name of Utility Company

The above named Applicant, ______________________________, personally appeared before me this day and, being first duly sworn, says that the required copy of the Commission Order was mailed or hand delivered to all affected customers, as required by the Commission Order dated __________________ in Docket No. W-933, Sub 11.

Witness my hand and notarial seal, this the ____ day of ________________, 2018.

____
Notary Public

____
Printed or Typed Name

(SEAL) My Commission Expires: ____________________________
Date

DOCKET NO. W-1317, SUB 12

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Recommendation of Penalty by the N.C. Underground Damage Prevention Review Board against Scott Beatty for Violation of the Underground Utility Safety and Damage Prevention Act	)))))	ORDER IMPOSING PENALTY

BY THE COMMISSION: On August 8, 2018, the Underground Damage Prevention Review Board (the Board) notified the Commission that the Board made a final determination in the above-captioned proceeding, recommending a penalty be assessed against Scott Beatty of Everything Underground, for a violation of the provisions of Chapter 87, Article 8A of the General Statutes. The Board recommends that Mr. Beatty in be required to pay a civil penalty of $1,000.00. The Board further states that it notified Mr. Beatty of its determination and that the time period for Mr. Beatty to request a hearing before the Board has expired. Pursuant to N.C.G.S. § 87-129(b1), the Commission shall issue an order imposing the Board's recommended penalty.

IT IS, THEREFORE, ORDERED as follows:

1. That upon the recommendation of the N.C. Underground Damage Prevention Review Board Scott Beatty of Everything Underground, shall be, and is hereby, required to pay a civil penalty of $1000.00;

2. That the Chief Clerk of the Commission shall deliver a copy of this order to Scott Beatty of Everything Underground, with an explanation of the right to appeal provided in N.C.G.S. § 87-129(b1), attached hereto as Attachment A; and

3. That Scott Beatty of Everything Underground, shall, within thirty days of the date of this order, file with the Commission either a notice of appeal or evidence of completion of the required training and education.

ISSUED BY ORDER OF THE COMMISSION.
This the 13th day of December, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

Attachment A. Explanation of Right to Appeal under N.C.G.S. § 87-129.

Pursuant to the foregoing Order Imposing Penalty, the North Carolina Underground Damage Prevention Review Board (the Board) determined that you violated one or more provisions of the Underground Utility Safety and Damage Prevention Act (the Act) and recommended that a penalty be assessed against you.

You have the right to appeal the Board's determination by initiating an arbitration proceeding before the Utilities Commission within 30 days of the date of this Order. If you elect to initiate an arbitration proceeding, you must file a written request in the docket assigned to your case and pay a filing fee of $250.00 to the Utilities Commission at the following address:

M. Lynn Jarvis, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, NC 27699-4300

When the Utilities Commission receives your written request and the $250.00 filing fee, the Commission will direct the parties to the dispute to select an arbitrator. An arbitrator is a neutral third party selected by the parties to resolve the dispute. The parties are responsible for selecting and contracting with the arbitrator. Upon completion of the arbitration process, the arbitrator will deliver a report to the Utilities Commission and the Utilities Commission will enter an order encompassing the outcome of the arbitration process, including a determination of fault, a penalty, and assessing the costs of arbitration to the non-prevailing party.

DOCKET NO. W-1160, SUB 32

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Notification by KDHWWTP, LLC, Post Office Box 3629, Kill Devil Hills, North Carolina 27948, of Intention to Begin Operations in an Area Contiguous to a Present Service Area to Provide Sewer Utility Service at 111 Carolyn Drive, Kill Devil Hills, Dare County, North Carolina	))))))	ORDER RECOGNIZING CONTIGUOUS EXTENSION

BY THE COMMISSION: On November 9, 2017, KDHWWTP, LLC (KDH), filed a notification of intention to begin operations in an area contiguous to a present service area. KDH desires to expand sewer utility service to a new customer, Florida OBX, LLC (Florida OBX) at 111 Carolyn Drive, Kill Devil Hills, Dare County, North Carolina. The service area covered is the area shown on the plans attached as Appendix B to the notification form filed in this docket. Florida OBX is located close to the footprint of KDH's service territory. KDH states that there are no other sewer service providers, either public utility or municipal, in the location which KDH proposes to serve. KDH's proposed rates are the same as currently approved in its present franchised service area.

The Public Staff presented this matter at the Commission's Staff Conference on March 5, 2018.

Based upon the verified notification and the entire record in this matter, the Commission makes the following

FINDINGS OF FACT

1. KDH presently holds a sewer franchise serving approximately 62 customers in Dare County, North Carolina, and its record of service is satisfactory.

2. KDH has an unusual certificate of public convenience and necessity because the service area was defined as customers being served rather than a geographical area.[1] Florida OBX is located close to the existing customers and along an existing KDH main. KDH states that there are no other sewer service providers, either public utility or municipal, in the location that KDH proposes to serve. In the unusual circumstance of a service area defined by customers rather than geography, and especially given the unusual history of this franchise, and without creating a precedent for other cases, the Commission will treat the matter as a contiguous extension.

3. Under Permit No. WQ0002829, dated July 14, 2017, the North Carolina Department of Environmental Quality, Division of Water Resources (DWR) approved modifying the disposal capacity from 500,000 gallons per day (gpd) to 660,000 gpd.

[1] See Docket No. W-1160, Sub 0.

4. KDH has entered an agreement with Florida OBX to sell capacity from its wastewater treatment plant at its Commission-approved capacity fee of $12.98 per gpd. Under the agreement, Florida OBX is allocated 1,320 gpd of capacity for a total purchase price of $17,133.60. Pursuant to the agreement, Florida OBX will install any required wastewater pump station as well as necessary piping and equipment to connect to the existing KDH collection system. Upon completion, and upon request of KDH, the pump station and pipes will be conveyed to KDH at no cost. The pump station will require a DWR Water Quality Permit prior to connecting to KDH system.

5. KDH has requested waiver of filing the five-year projected income and cash flow statements as only one customer is being added using only 1,320 gpd of capacity, which will not have a significant impact on KDH's revenues and expenses. The Public Staff supported this request, and the Commission finds the request reasonable under the circumstances.

6. KDH has the technical, managerial, and financial capacity to provide sewer utility service for the proposed service connection.

7. KDH posted a $150,000 bond in Docket No. W-1160, Sub 16, which was designated to cover all extensions of service up to the 500,000 gallons per day of wastewater treatment capacity. Therefore, no additional bond will be required for this application.

CONCLUSIONS

Based on the foregoing and the recommendations of the Public Staff, the Commission is of the opinion that the bond previously posted in Docket No. W-1160, Sub 16, should be accepted as covering the notification in this docket; that prior to accepting Florida OBX onto the KDH system, KDH shall obtain ownership and operational responsibility for the pump station and line from the pump station to the KDH collection system and a DWR Permit issued in the name of KDH; that KDH should file written notification with the Commission when such requirements have been met; and that the notification to provide sewer service to 111 Carolyn Drive, Kill Devil Hills, Dare County, North Carolina should be recognized.

IT IS, THEREFORE, ORDERED as follows:

1. That the $150,000 bond and surety filed in Docket No. W-1160, Sub 16, is intended to cover the service expansion in this notification and is hereby accepted and approved.

2. That the contiguous extension of sewer utility service from KDH's existing service area to 111 Carolyn Drive, in Kill Devil Hills, Dare County, North Carolina, is hereby recognized.

3. That Appendix A constitutes the Certificate of Public Convenience and Necessity.

4. That the Schedule of Rates previously approved for KDH (see Docket Nos. W-1160, Sub 24 and M-100, Sub 138 Order Approving Tariff Revision and Requiring Customer Notice dated December 7, 2016) are recognized as being applicable for service to a commercial customer. These are the same rates approved by the Commission for KDH's other franchised areas.

5. That prior to accepting the customer, KDH shall obtain ownership and operational responsibility for the pump station and line from the pump station to the KDH collection system and a DWR Permit issued in the name of KDH. Further, KDH shall file a written notification with the Commission when these requirements have been met.

ISSUED BY ORDER OF THE COMMISSION.
This the 9th day of March, 2018.

NORTH CAROLINA UTILITIES COMMISSION
M. Lynn Jarvis, Chief Clerk

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-1160, SUB 32

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

KDHWWTP, LLC
is granted this

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY
to provide sewer utility service

for

111 CAROLYN DRIVE, KILL DEVIL HILLS

Dare County, North Carolina,
subject to any orders, rules, regulations,
and conditions now or hereafter lawfully made
by the North Carolina Utilities Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 9th day of March, 2018.

NORTH CAROLINA UTILITIES COMMISSION
M. Lynn Jarvis, Chief Clerk

DOCKET NO. WR-910, SUB 24

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Southwood Realty Company, Post Office Box 280, Gastonia, North Carolina 28053, for Certificate of Authority to Charge for Water and/or Sewer Service Utilizing the Hot Water Capture, Cold Water Allocation Method in The Park Apartments in Gaston County, North Carolina	)))))))	ORDER GRANTING HWCCWA CERTIFICATE OF AUTHORITY AND APPROVING RATES

BY THE COMMISSION: On January 5, 2018, Southwood Realty Company (Applicant), filed an application with the Commission seeking a **hot water capture, cold water allocation (HWCCWA)** certificate of authority to charge for water and/or sewer utility service provided in The Park Apartments in Gaston County, North Carolina, and for approval of rates. The Applicant purchases water and sewer service from Two Rivers Utilities (TRU).

On July 14, 2017, in Docket No. WR-910, Sub 22, the Commission granted a full-capture certificate of authority to the Applicant for providing water and sewer service to all 118 units at The Park Apartments. In this current application, the Applicant is requesting that the full-capture certificate of authority for The Park Apartments (all 118 units) be converted to a HWCCWA certificate of authority.

Based upon the filings of the Applicant, the Public Staff has recommended approval of an Administrative Fee of $13.20 (consisting of $3.75 for the Applicant's meter reading, billing, and collecting costs plus a pass through of TRU's $9.45 base charge for water and sewer service). Based upon 4,000 gallons per month usage and rates of $2.95 per 1,000 gallons for water and $3.88 per 1,000 gallons for sewer, the total monthly bill will be $40.52 ($27.32 usage charge and $13.20 administrative fee).

Based upon the foregoing, the Commission is of the opinion that the Applicant should be granted a HWCCWA certificate of authority to charge for water and/or sewer service and that the Public Staff's recommended rates should be approved. Further, the Commission finds and concludes that the full-capture certificate of authority granted on July 14, 2017, in Docket No. WR-910, Sub 22, should be canceled. The Commission is also of the opinion that, if TRU's base charge should be reduced for any reason, the Applicant should be required to notify the Commission immediately for a tariff revision.

IT IS, THEREFORE, ORDERED as follows:

1. That Southwood Realty Company, is granted a HWCCWA certificate of authority to charge for water and/or sewer service for The Park Apartments in Gaston County, North Carolina, pursuant to G.S. 62-110(g)(1) and Commission Rules R18-1 through R18-8 (see

http://www.ncuc.net/ncrules/Chapter18.pdf). This Order shall constitute the Certificate of Authority to Charge for Water and/or Sewer Service.

2. That the Schedule of Rates, attached as Appendix A, is approved and deemed to be filed with the Commission pursuant to G.S. 62-138. **Said Schedule of Rates is authorized to become effective for service rendered on and after the date of this Order.**

3. That, if TRU's base charge should be reduced for any reason, the Applicant shall notify the Commission immediately for a tariff revision.

4. That a copy of the Notice to Customers, attached as Appendix B, shall be mailed with sufficient postage or hand delivered by the Applicant to all its customers in The Park Apartments contemporaneously with the next billing to customers.

5. That the full-capture certificate of authority issued to Southwood Realty Company, in Docket No. WR-910, Sub 22, is hereby canceled.

6. That, if the service area is sold or the ownership changes, the Applicant and the new owner shall file an Application for Transfer of Authority (Form WR2 may be found on the Commission's website – www.ncuc.net). Failure to do so may result in revocation of the certificate of authority and suspension of rates.

ISSUED BY ORDER OF THE COMMISSION.
This the 17th day of January , 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

APPENDIX A

SCHEDULE OF RATES

for

SOUTHWOOD REALTY COMPANY
for water and sewer utility **(HWCCWA)** service in

THE PARK APARTMENTS
Gaston County, North Carolina

Monthly Metered Rates:

Water usage charge, per 100 cubic feet (ccf)	$2.21
Sewer usage charge, per 100 cubic feet (ccf)	$2.90
or	
Water usage charge, per 1,000 gallons	$2.95
Sewer usage charge, per 1,000 gallons	$3.88

WATER RESELLERS – CERTIFICATE

Monthly Administrative Fee:	$13.20 per unit
Bills Due:	On billing date
Bills Past Due:	25 days after billing date
Billing Frequency:	Shall be monthly for service in arrears

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. WR-910, Sub 24, on this the 17th day of January , 2018.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

APPENDIX B

NOTICE TO CUSTOMERS
DOCKET NO. WR-910, SUB 24
BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

Notice is given that the North Carolina Utilities Commission has granted Southwood Realty Company (Post Office Box 280, Gastonia, North Carolina 28053), a **HWCCWA** certificate of authority to charge for water and/or sewer service provided in The Park Apartments in Gaston County, North Carolina, for the purpose of passing along the cost of purchasing water and sewer utility service from Two Rivers Utilities. The rates approved by the Commission are as follows and are effective for service provided on and after the date of this Notice:

Monthly Metered Rates:

Water usage charge, per 100 cubic feet (ccf)	$2.21
Sewer usage charge, per 100 cubic feet (ccf)	$2.90
or	
Water usage charge, per 1,000 gallons	$2.95
Sewer usage charge, per 1,000 gallons	$3.88

Monthly Administrative Fee: $13.20 per unit

The average monthly residential water and sewer bill will be $40.52, based on an estimated average usage of 4,000 gallons.

ISSUED BY ORDER OF THE COMMISSION.
This the 17th day of January , 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

DOCKET NO. WR-2488, SUB 0
DOCKET NO. WR-1642, SUB 1
DOCKET NO. WR-2488, SUB 1

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. WR-2488, SUB 0 DOCKET NO. WR-1642, SUB 1 In the Matter of Application by Evolve Sneads Ferry, LLC, 2918-A Martinsville Road, Greensboro, North Carolina 27408, for Authority to Transfer Certificate of Authority to Charge for Water and/or Sewer Utility Service in Evolve at Stones Bay Apartments (formerly The Quarters at Stones Bay Apartments, Phase II) in Onslow County, North Carolina from The Quarters at Stones Bay II, LLC DOCKET NO. WR-2488, SUB 1 In the Matter of Application by Evolve Sneads Ferry, LLC, 2918-A Martinsville Road, Greensboro, North Carolina 27408, for Certificate of Authority to Charge for Water and/or Sewer Service in Evolve at Stones Bay Apartments (formerly The Quarters at Stones Bay Apartments, Phase I) in Onslow County, North Carolina	ORDER GRANTING TRANSFER OF CERTIFICATE OF AUTHORITY, GRANTING CERTIFICATE OF AUTHORITY, COMBINING CERTIFICATES OF AUTHORITY, AND APPROVING RATES

BY THE COMMISSION: On January 23, 2018, Evolve Sneads Ferry, LLC (Applicant), filed an application with the Commission seeking authority to transfer the certificate of authority to charge for water and/or sewer utility service provided in Evolve at Stones Bay Apartments (formerly The Quarters at Stones Bay Apartments, (Phase II) in Onslow County, North Carolina, from The Quarters at Stones Bay II, LLC and for approval of rates.

On January 31, 2018, in Docket No. WR-2488, Sub 1, the Applicant filed an application with the Commission seeking a certificate of authority to charge for water and/or sewer utility service provided in Evolve at Stones Bay Apartments (formerly The Quarters at Stones Bay Apartments, Phase I) in Onslow County, North Carolina, and for approval of rates.

In its applications, the Applicant has requested to combine The Quarters at Stones Bay Apartments, Phases I and II into one apartment complex known as Evolve at Stones Bay Apartments and for the Commission to combine the two separate certificates of authority to charge for water and/or sewer utility service in Evolve At Stones Bay Apartments into one certificate of authority which includes both phases. The Applicant purchases water service from Onslow Water and Sewer Authority (ONWASA).

Based upon the filings of the Applicant, the Public Staff has recommended approval of an Administrative Fee of $7.79 (consisting of $3.75 for the Applicant's meter reading, billing, and collecting costs plus a pass through of ONWASA's $4.04 base charge for water service). Based upon 4,000 gallons per month usage and rates of $3.75 per 1,000 gallons for water, the total monthly bill will be $22.79 ($15.00 usage charge and $7.79 administrative fee).

Based upon the foregoing, the Commission is of the opinion that the Applicant should be granted a certificate of authority to charge for water service in Evolve at Stones Bay Apartments (consisting of the combined Phases I and II) and that the Public Staff's recommended rates should be approved. The Commission is also of the opinion that, if ONWASA's base charge should be reduced for any reason, the Applicant should be required to notify the Commission immediately for a tariff revision.

IT IS, THEREFORE, ORDERED as follows:

1. That Evolve Sneads Ferry, LLC, is granted a certificate of authority to charge for water service in Evolve at Stones Bay Apartments (consisting of the combined Phases I and II) in Onslow County, North Carolina, pursuant to G.S. 62-110(g)(1). This Order shall constitute the Certificate of Authority to Charge for Water Service.

2. That the Schedule of Rates, attached as Appendix A, is approved and deemed to be filed with the Commission pursuant to G.S. 62-138. **Said Schedule of Rates is authorized to become effective for service rendered on and after the date of this Order.**

3. That, if ONWASA's base charge should be reduced for any reason, the Applicant shall notify the Commission immediately for a tariff revision.

4. That a copy of the Notice to Customers, attached as Appendix B, shall be mailed with sufficient postage or hand delivered by the Applicant to all their customers in Evolve at Stones Bay Apartments contemporaneously with the next billing to customers.

5. That the certificate of authority issued to The Quarters at Stones Bay II, LLC, in Docket No. WR-1642, Sub 0, is hereby canceled.

6. That, if the service area is sold or the ownership changes, the Applicant and the new owner shall file an Application for Transfer of Authority (Form WR2 may be found on the Commission's website – www.ncuc.net). Failure to do so may result in revocation of the certificate of authority and suspension of rates.

ISSUED BY ORDER OF THE COMMISSION.
This the 15th day of February, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

APPENDIX A

SCHEDULE OF RATES

for

EVOLVE SNEADS FERRY, LLC

for water utility service in

EVOLVE AT STONES BAY APARTMENTS

Onslow County, North Carolina

Monthly Metered Rates:

Water usage charge, per 100 cubic feet (ccf) $2.81

or

Water usage charge, per 1,000 gallons $3.75

Monthly Administrative Fee:	$7.79 per unit
Bills Due:	On billing date
Bills Past Due:	25 days after billing date
Billing Frequency:	Shall be monthly for service in arrears

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. WR-2488, Sub 1, on this the 15th day of February, 2018.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

APPENDIX B

NOTICE TO CUSTOMERS
DOCKET NO. WR-2488, SUB 1
BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

Notice is hereby given that the North Carolina Utilities Commission has granted Evolve Sneads Ferry, LLC (2918-A Martinsville Road, Greensboro, North Carolina 27408), a certificate of authority to charge for water utility service provided in Evolve at Stones Bay Apartments in Onslow County, North Carolina, for the purpose of passing along the cost of purchasing water utility service from Onslow Water and Sewer Authority. The Commission has approved the following rates effective for service provided on and after the date of this Notice:

Monthly Metered Rates:

Water usage charge, per 100 cubic feet (ccf)	\$2.81
or	
Water usage charge, per 1,000 gallons	\$3.75
Monthly Administrative Fee:	\$7.79 per unit

The average monthly residential water and sewer bill will be \$22.79, based on an estimated average usage of 4,000 gallons.

ISSUED BY ORDER OF THE COMMISSION.
This the 15th day of February, 2018.

NORTH CAROLINA UTILITIES COMMISSION
Janice H. Fulmore, Deputy Clerk

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Apple Pie Solar, LLC	SP-8263, SUB 0	(09/25/2018)
Bay Branch Solar, LLC	SP-7800, SUB 0	(08/21/2018)
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North 301 Solar, LLC	SP-5422, SUB 0	(12/31/2018)
Plott Hound Solar, LLC	SP-8218, SUB 0	(08/21/2018)
Ray Wilson Solar Farm, LLC	SP-7799, SUB 0	(09/24/2018)
Sabattus Solar, LLC	SP-3810, SUB 0	(08/21/2018)
Union Chapel Solar, LLC	SP-8208, SUB 0	(09/25/2018)
Vintage Solar 2, LLC	SP-8206, SUB 0	(08/21/2018)
1025 Traveller Solar, LLC	SP-8406, SUB 0	(09/25/2018)

Bay Branch Solar, LLC -- SP-7800, SUB 0; Order Allowing Limited Construction with Conditions (08/21/2018)
Buckleberry Solar, LLC -- SP-5275, SUB 0; Order Amending Certificate of Public Convenience and Necessity and Registration ((11/15/2018)
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Flowers Solar, LLC -- SP-5092, SUB 0; Order Amending Certificate of Public Convenience and Necessity and Registration (01/22/2018)
Pecan Grove Solar, LLC -- SP-8341, SUB 0; Order Reaffirming Certificate of Public Convenience and Necessity (09/25/2018)
Swansboro Solar, LLC -- SP-8342, SUB 0; Order Issuing Amended Certificate of Public Convenience and Necessity (09/25/2018)
Sweet Tea Solar, LLC -- SP-8250, SUB 0; Order Issuing Amended Certificate of Public Convenience and Necessity (09/25/2018)
White Street Renewables LLC -- SP-4640, SUB 0; SP-4640, SUB 1; Order Amending Certificate of Public Convenience and Necessity (10/03/2018)
1034 Catherine Lake Solar, LLC -- SP-8402, SUB 0; Order Issuing Amended Certificate of Public Convenience and Necessity (09/26/2018)
1035 Lee Landing Solar, LLC -- SP-8405, SUB 0; Order Issuing Amended Certificate of Public Convenience and Necessity (09/25/2018)
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Sugar Solar, LLC	SP-11728, SUB 0	(10/02/2018)
Two Hearted Solar, LLC	SP-11727, SUB 0	(10/16/2018)
Uzzell Solar, LLC	SP-11956, SUB 0	(10/16/2018)

Williamston Hwy 125 Solar, LLC -- SP-12149, SUB 0; Order Issuing Certificate of Public Convenience and Necessity (09/05/2018)

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Cougar Solar, LLC	SP-7501, SUB 0	(04/24/2018)
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(Colonial Grand at Cornelius Apts.)	WR-22, SUB 92 WR-437, SUB 66	(03/13/2018)
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(Colonial Village at Matthews Apts.)	WR-22, SUB 94 WR-977, SUB 6	(05/02/2018)
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(Timber Crest at Greenway Apts.)	WR-22, SUB 96 WR-412, SUB 10	(04/10/2018)
(Colonial Grand at Trinity Commons Apts.)	WR-22, SUB 124 WR-415, SUB 12	(10/09/2018)

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(Millbrook Apartments)	WR-2606, SUB 1 WR-1725, SUB 4	(08/27/2018)
MRP North Pointe, LLC		
(Altera North Pointe Apartments)	WR-2533, SUB 0 WR-1950, SUB 2	(04/24/2018)
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Raleigh City Center Owner, LLC		
(Elan City Center Apartments)	WR-2665, SUB 0 WR-1928, SUB 4	(11/26/2018)
Renaissance Cary, LLC		
(Apartments at the Arboretum)	WR-2637, SUB 0 WR-1277, SUB 6	(11/01/2018)
Retreat at the Park Holdings SPE, LLC		
(Retreat at the Park Apts.; The)	WR-2642, SUB 0 WR-2146, SUB 3	(10/29/2018)
RRPV Tremont Charlotte, LP		
(335 Apartments)	WR-2566, SUB 0 WR-1548, SUB 5	(07/02/2018)
Runner Fund, LLC		
(Sherwood Mobile Home Park)	WR-2454, SUB 0 WR-1044, SUB 7	(12/20/2018)
(Triple Overlook Mobile HP)	WR-2454, SUB 1 WR-1047, SUB 7	(12/21/2018)
Selwyn Multifamily Partners, LLC		
(3400 Selwyn Apartments)	WR-2653, SUB 0 WR-959, SUB 4	(11/20/2018)
Sommerset Place Apartments, LLC		
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Station Nine Owner, LLC		
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TBR Optimist Owner, LLC		
(300 Optimist Park Apartments)	WR-2627, SUB 0 WR-2528, SUB 1	(10/04/2018)
TH Property Owner 1, LP		
(Sailpointe at Lake Norman Apts.)	WR-2646, SUB 0 WR-2092, SUB 1	(11/26/2018)
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(Elan at Mallard Creek Apartments)	WR-2648, SUB 0 WR-2091, SUB 1	(11/26/2018)
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(Bridges at Mallard Creek Apts.)	WR-2649, SUB 0 WR-2090, SUB 1	(11/26/2018)
TH Property Owner 4, LP		
(Paces Pointe Apartments)	WR-2651, SUB 0 WR-2093, SUB 1	(11/26/2018)
TH Property Owner 5, LP		
(Brook Apartments; The)	WR-2652, SUB 0 WR-2089, SUB 1	(11/27/2018)
TH Property Owner 6, LP		
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TH Property Owner 7, LP		
(Madison Southpark Apartments)	WR-2655, SUB 0 WR-2088, SUB 1	(11/27/2018)
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TH Property Owner 10, LP		
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Waypoint CapCreek MF Owner, LLC		
(Capital Creek at Heritage Apts.)	WR-2514, SUB 0 WR-2218, SUB 2	(03/27/2018)
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(Aurea Station Apartments)	WR-2465, SUB 0 WR-1853, SUB 3	(01/09/2018)
WOP Highland Park, LLC		
(Highland Park at Northlake Apts.)	WR-2612, SUB 0 WR-1999, SUB 3	(09/27/2018)
150W CGC, LLC		
(150 West Apartments)	WR-2661, SUB 0 WR-2224, SUB 1	(11/20/2018)
412 Pilot, LLC		
(Eagle Point Apartments)	WR-2506, SUB 0 WR-2413, SUB 1	(03/07/2018)
3119 Enterprise Drive, LLC		
(North Chase Apartments)	WR-2595, SUB 0 WR-1821, SUB 2	(08/10/2018)

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CPoint, LLC		
(Aria North Hills Apartments)	WR-2676, SUB 0 WR-1681, SUB 6	(12/20/2018)
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4009 Deep Hollow, LLC		
(Casa Del Sol Apartments)	WR-2585, SUB 0 WR-2179, SUB 3	(08/08/2018)
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(Lexington on the Green Apts.)	WR-2497, SUB 0 WR-2414, SUB 1	(02/27/2018)
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Barrington Apartments, LLC		
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Belle Meade Development Partners, LLC *(Belle Meade Apartments)*	WR-1942, SUB 3	(07/24/2018)
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BPP Stoney Ridge, LLC		
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BR Chapel Hill, LLC		
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BRC Alexandria Park, LLC		
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BRC Charlotte 485, LLC		
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BRC Jacksonville Commons, LLC		
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BRC Knightdale, LLC		
(Berkshire Park Apartments)	WR-938, SUB 10	(08/07/2018)
BRC Majestic Apartments, LLC		
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BRC Salisbury, LLC		
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BRNA, LLC		
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Brookberry Park Apartments, LLC		
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BR-TBR Lake Boone NC Owner, LLC		
(Leigh House Apartments)	WR-2435, SUB 1	(10/24/2018)
BR-TBR Whetstone Owner, LLC		
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Carolina Village MHC, LLC *(Carolina Village Mobile Home Park)*	WR-1215, SUB 3	(02/20/2018)
Cary Greens, LP *(Cary Greens at Preston Apts.)*	WR-2380, SUB 1	(10/10/2018)
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CCC Brassfield Park, LLC *(Brassfield Park Apartments)*	WR-1619, SUB 5	(08/13/2018)
CCC Caliber Chase, LLC *(Calibre Chase Apartments)*	WR-1886, SUB 2	(08/21/2018)
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CCC Mezzo1, LLC, et al. *(Mezzo1 Apartments)*	WR-2067, SUB 3	(10/18/2018)
CCC One Norman Square, LLC *(One Norman Square Apartments)*	WR-1628, SUB 4	(08/29/2018)
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(Sterling Magnolia Apartments)	WR-231, SUB 7	(02/05/2018)
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CEG Friendly Manor, LLC		
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Centennial Addington Farms, LLC		
(Century Trinity Estates Apartments)	WR-1403, SUB 6	(07/16/2018)
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Centennial Tryon Place, LLC		
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Chamberlain Place Apartments, LLC		
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Chatham Mill Ventures, LLC		
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CLT Whitehall, LLC		
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CMF 15 Portfolio, LLC		
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(Colonial Grand at Crabtree Apts.)	WR-955, SUB 38	(02/19/2018)
(Colonial Grand at Mallard Creek Apts.)	WR-955, SUB 39	(02/16/2018)
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(Colonial Grand at Patterson Place Apts.)	WR-955, SUB 41	(02/15/2018)
(Colonial Grand at Beverly Crest Apts.)	WR-955, SUB 43	(09/26/2018)
(Colonial Grand at Brier Creek Apts.)	WR-955, SUB 44	(09/26/2018)
(Colonial Grand at Crabtree Apts.)	WR-955, SUB 45	(09/26/2018)
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CPGPI Still Meadow, LLC		
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Crabtree Apartments, LLC		
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Creekview Professional Centre, LLC		
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Crescent NoDa, LLC		
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Crest at Brier Creek Investments SPE, LLC		
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Crestmont at Ballantyne Apartments, LLC		
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(Crossroads North Hills Apts.)	WR-2487, SUB 1	(12/03/2018)
Cross Point NC Partners, LLC		
(Sardis Place at Matthews Apartments)	WR-1851, SUB 3	(10/09/2018)
CRP-GREP Overture Crabtree Owner, LLC		
(Overture Crabtree Apartments)	WR-2449, SUB 1	(10/10/2018)
CRP/WF Gateway Owner, LLC		
(BullHouse Apartments)	WR-2356, SUB 1	(01/30/2018)
CSP Community Owner, LLC		
(Camden Dilworth Apartments)	WR-909, SUB 43	(09/27/2018)
(Camden Sedgebrook Apartments)	WR-909, SUB 44	(09/27/2018)
(Camden Manor Park Apartments)	WR-909, SUB 45	(10/02/2018)
(Camden Lake Pine Apartments)	WR-909, SUB 46	(10/02/2018)
(Camden Reunion Park Apts.)	WR-909, SUB 47	(10/15/2018)
(Camden Westwood Apartments)	WR-909, SUB 48	(10/02/2018)
(Camden Ballantyne Apartments)	WR-909, SUB 49	(11/13/2018)

<u>**WATER RESELLERS – Tariff Revision for Pass-Through**</u> *(Continued)*

ORDER APPROVING TARIFF REVISION
<u>Orders Issued</u> (Continued)

WATER RESELLERS – Tariff Revision for Pass-Through *(Continued)*

ORDER APPROVING TARIFF REVISION
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WATER RESELLERS – Tariff Revision for Pass-Through *(Continued)*

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Company	Docket No.	Date
Forest at Chasewood Apartments, LLC		
(Forest at Chasewood Apartments; The)	WR-1997, SUB 3	(08/27/2018)
Forest Hill Apartments, LLC		
(Reserve at Forest Hills Apts.; The)	WR-34, SUB 13	(08/07/2018)
Forestdale W99 LAP, LLC		
(Hawthorne at Forestdale Apartments)	WR-1847, SUB 4	(12/20/2018)
Formax Properties, LLC		
(Mobile Acres II Mobile HP)	WR-899, SUB 6	(05/08/2018)
(L & W Mobile Home Park)	WR-899, SUB 7	(05/08/2018)
Fortune Bay Associates, LLC		
(Forest Pointe Apartments)	WR-785, SUB 12	(11/14/2018)
Fountains Matthews, LLC		
(Fountains Matthews Apartments)	WR-2023, SUB 1	(04/24/2018)
(Fountains Matthews Apartments)	WR-2023, SUB 2	(10/08/2018)
Free Throw NC Partners, LLC		
(Pointe Apartments; The)	WR-1855, SUB 3	(11/26/2018)
Fund Asbury Village, LLC		
(Camden Asbury Village Apartments)	WR-1211, SUB 4	(10/02/2018)
Fund Southline, LLC		
(Camden Southline Apartments)	WR-1789, SUB 4	(09/27/2018)
FWDA, LLC		
(Franklin Woods Apartments)	WR-1105, SUB 3	(09/24/2018)
G Colonial, LLC		
(Autumn Trace Apartments, Phase I)	WR-1829, SUB 9	(08/20/2018)
(Empire Crossing Apartments)	WR-1829, SUB 10	(08/20/2018)
(Colonial Apartments, Phases 5 & 6)	WR-1829, SUB 11	(08/20/2018)
G Partnership, LP		
(The Landings Apartments)	WR-1262, SUB 7	(08/30/2018)
Galleria Partners II, LLC		
(Crest Apartments at Galleria; The)	WR-925, SUB 6	(08/21/2018)
Gateway West-FCA, LLC		
(Gateway West Uptown Flats Apts.)	WR-1561, SUB 5	(12/04/2018)
General Greene, LLC		
(Pinewood Apartments)	WR-486, SUB 6	(07/31/2018)
Ginkgo Abbington, LLC		
(Abbington Place Apartments)	WR-1962, SUB 3	(08/08/2018)
Ginkgo Arbor Creek, LLC		
(Arbor Creek Apartments)	WR-2483, SUB 1	(10/04/2018)

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Ginkgo Biscayne, LLC		
(Biscayne Apartments)	WR-2442, SUB 1	(10/24/2018)
Ginkgo Briar Creek, LLC		
(Aurora Village Apartments)	WR-2443, SUB 1	(10/24/2018)
Ginkgo Brookford, LLC		
(Brookford Place Apartments)	WR-2258, SUB 2	(09/18/2018)
Ginkgo BVG, LLC		
(Boundary Village Apartments)	WR-1519, SUB 6	(08/27/2018)
Ginkgo Kimmerly, LLC		
(Kimmerly Glen Apartments)	WR-1729, SUB 4	(08/27/2018)
Ginkgo OBC, LLC		
(Aurora Apartments)	WR-1558, SUB 6	(08/27/2018)
Ginkgo Parkwood, LLC		
(Parkwood Apartments)	WR-2275, SUB 3	(09/18/2018)
Ginkgo Salem Ridge, LLC		
(Salem Ridge Apartments)	WR-2259, SUB 2	(09/18/2018)
Ginkgo Savannah, LLC		
(Savannah Place Apartments)	WR-1937, SUB 3	(09/17/2018)
Ginkgo Willowdaile, LLC		
(Willowdaile Apartments)	WR-2530, SUB 1	(10/04/2018)
Glenhaven G, LLC		
(Glen Haven Apartments, Phase 3)	WR-1873, SUB 3	(08/30/2018)
Glenhaven K, LLC		
(Glen Haven Apartments, Phase 1 & 2)	WR-1872, SUB 3	(08/30/2018)
Glenwood South Raleigh Apartments, LLC		
(Link Glenwood South Apartments)	WR-1877, SUB 4	(09/06/2018)
Golden Triangle #1, LLC		
(Crest at Greylyn Apartments)	WR-1400, SUB 5	(08/20/2018)
Golden Triangle #4-5th Street, LLC		
(Crest Gateway Apartments)	WR-1809, SUB 4	(08/20/2018)
Golden Triangle #7 – Commonwealth, LLC		
(Julien Apartments; The)	WR-2097, SUB 3	(09/20/2018)
Grace Park Development, LLC		
(Grace Park Apartments)	WR-893, SUB 8	(02/20/2018)
(Grace Park Apartments)	WR-893, SUB 9	(08/13/2018)
Gramercy Glenwood, LLC		
(Gramercy Apartments; The)	WR-2123, SUB 2	(10/23/2018)

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Company	Docket No.	Date
Grand View Holdings, LLC		
(Grand View Apartments)	WR-2042, SUB 2	(04/23/2018)
Granite Ridge Investments, LLC		
(Granite Ridge Apartments)	WR-295, SUB 9	(10/30/2018)
(Granite Ridge Apartments)	WR-295, SUB 10	(12/19/2018)
Gray Property 2004, LLC		
(Exchange at Brier Creek Apts.; The)	WR-1967, SUB 3	(09/13/2018)
GrayBul Meadows, LP		
(Meadows Apartments; The, Phase II)	WR-2030, SUB 8	(10/22/2018)
GRE JV Wilmington, LLC		
(Park at Three Oaks Apartments; The)	WR-2186, SUB 2	(07/31/2018)
GRE Windsor Owner, LLC		
(Windsor Falls Apartments)	WR-2479, SUB 1	(10/10/2018)
Greenfield Village NC, LLC		
(Greenfield Village Mobile Home Park)	WR-954, SUB 4	(09/07/2018)
Greenfield Workforce Housing, LLC		
(Greenfield Place Apartments)	WR-2400, SUB 1	(08/10/2018)
Greens at Tryon, LLC		
(Greens at Tryon Apartments; The)	WR-2368, SUB 1	(08/13/2018)
Greenville Village, LLC		
(Greenville Mobile Home Park)	WR-648, SUB 8	(10/10/2018)
Greystone WW Company, LLC		
(Greystone at Widewaters Apartments)	WR-517, SUB 11	(08/08/2018)
GS Village, LLC		
(Village Apartments; The)	WR-564, SUB 13	(08/23/2018)
Guardian Tryon Village, LLC		
(Windsor at Tryon Village Apts.)	WR-1335, SUB 6	(08/16/2018)
GUGV Poplar Charlotte Property Owning, LP		
(Ascent Uptown Apartments)	WR-2267, SUB 2	(09/05/2018)
Hamilton Florida Partners, LLC		
(Hamilton Square Apartments)	WR-841, SUB 7	(09/04/2018)
Hanover Terrace, LLC		
(Hanover Terrace Apartments)	WR-622, SUB 11	(08/10/2018)
Happy Hill, Inc.		
(Willow Lake Mobile Home Park)	WR-512, SUB 5	(10/12/2018)
Harris Pointe, LLC		
(Harris Pointe Apartments)	WR-756, SUB 7	(02/27/2018)

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Orders Issued (Continued)

Company	Docket No.	Date
Hawthorne Arden, LLC		
(Hawthorne Midtown Apartments)	WR-2156, SUB 2	(07/25/2018)
Hawthorne at Leland Apartments, LLC		
(Hawthorne at Leland Apartments)	WR-2162, SUB 1	(02/26/2018)
(Hawthorne at Leland Apartments)	WR-2162, SUB 2	(09/04/2018)
Hawthorne-Midway Bear Creek, LLC, et al.		
(Hawthorne at Bear Creek Apartments)	WR-1899, SUB 2	(08/30/2018)
Hawthorne-Midway Cadence, LLC		
(Hawthorne at the Peak Apartments)	WR-1485, SUB 4	(09/20/2018)
Hawthorne Midway Deerwood, LLC, et al.		
(Hawthorne at Oak Ridge Apartments)	WR-2505, SUB 1	(10/03/2018)
Hawthorne-Midway Dunhill, LLC		
(Hawthorne at the Trace Apts.)	WR-1430, SUB 5	(07/30/2018)
Hawthorne-Midway Madison Place, LLC		
(Hawthorne at Main Apartments)	WR-1300, SUB 6	(09/13/2018)
Hawthorne-Midway Meadows, LLC		
(Hawthorne at the Meadows Apts.)	WR-1307, SUB 6	(09/13/2018)
Hawthorne-Midway Stratford, LLC, et al.		
(Hawthorne at the Parkway Apts.)	WR-1553, SUB 5	(08/10/2018)
Hawthorne-Midway Summerwood, LLC		
(Hawthorne at the Hall Apartments)	WR-1194, SUB 8	(09/13/2018)
Hawthorne-Midway Turtle Creek Phase III		
(Hawthorne at Southside Apts., Phase III)	WR-2077, SUB 4	(08/31/2018)
Hawthorne-Midway Vista Park, LLC		
(Hawthorne at the Greene Apartments)	WR-1349, SUB 3	(09/17/2018)
Hawthorne-Midway Wilmington, LLC		
(Hawthorne at the Station Apartments)	WR-1622, SUB 2	(07/25/2018)
Headwaters at Autumn Hall, LLC		
(Headwaters at Autumn Hall Apts.)	WR-1362, SUB 3	(08/08/2018)
Heather Park Apartments (NC) Owner, LLC		
(Heather Park Apartments)	WR-2111, SUB 2	(08/13/2018)
Heatherwood Florida Partners, LLC		
(Heatherwood Trace Apartments)	WR-930, SUB 4	(08/31/2018)
Heritage at Arlington Apts.; LLC; The		
(Heritage at Arlington Apts.; The)	WR-1472, SUB 4	(08/14/2018)
Heritage at Arlington Apts., LLC; The, Phase II		
(Heritage at Arlington Apts.; The, Phase II)	WR-1986, SUB 2	(08/14/2018)

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Company	Docket No.	Date
Heritage Circle Apartments, LLC		
(Heritage Circle Apartments)	WR-1625, SUB 4	(10/15/2018)
Heritage Gardens, LLC		
(Ardmore Heritage Apartments)	WR-1533, SUB 4	(08/01/2018)
Heritage Pointe NC Partners, LLC		
(Hunt Club Apartments)	WR-1852, SUB 3	(11/26/2018)
Highland Oaks Apartments, LLC		
(Highland Oaks Apartments)	WR-2066, SUB 3	(10/01/2018)
Highland Quarters, LLC		
(Muirfield Village Apartments)	WR-520, SUB 12	(06/26/2018)
(Muirfield Village Apartments)	WR-520, SUB 13	(10/04/2018)
Highlands at Olde Raleigh, LLC		
(Highlands at Olde Raleigh Apts.)	WR-1443, SUB 5	(08/29/2018)
Highpoint Associates, LLC		
(Laurel Bluff Apartments)	WR-570, SUB 4	(03/05/2018)
Hillandale North, LLC		
(Clairmont at Hillandale North Apts.)	WR-2287, SUB 2	(08/13/2018)
HLLC CWS 205, LLC, et al.		
(Marq Midtown 205 Apartments)	WR-2246, SUB 2	(12/19/2018)
Holiday City MHC, LLC		
(Holiday City Mobile Home Park)	WR-1454, SUB 2	(10/29/2018)
Holly NC, LLC		
(Holly Hills Apartments)	WR-1290, SUB 7	(07/23/2018)
Horizon Acquisition #1, LLC		
(Autumn View Apartments)	WR-1306, SUB 1	(05/08/2018)
Horizon Acquisition #3, LLC		
(Heritage Apartments)	WR-1325, SUB 2	(07/17/2018)
HPI Windsor, LLC		
(Windsor Upon Stonecrest Apts.)	WR-2403, SUB 1	(08/09/2018)
HSRE Aspen Charlotte, LP		
(Aspen Charlotte Apartments)	WR-2416, SUB 1	(12/17/2018)
HTC Preston Reserve, LLC, et al.		
(Bell Preston Reserve Apartments)	WR-1180, SUB 7	(08/29/2018)
Hudson Capital Park Forest, LLC		
(Park Forest Apartments)	WR-1869, SUB 3	(08/13/2018)
Hudson Capital Steeplechase, LLC		
(Steeplechase Apartments)	WR-1868, SUB 3	(08/13/2018)

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Company	Docket No.	Date
Hudson Capital Weston, LLC		
(Cary Reserve at Weston Apts.)	WR-2481, SUB 1	(09/18/2018)
Hunt Hill Apartments, LLC		
(Retreat at Hunt Hill Apartments; The)	WR-1920, SUB 3	(08/21/2018)
Inman Park Investment Group, Inc.		
(Inman Park Apartments)	WR-383, SUB 15	(07/25/2018)
Innesbrook Apartments, LLC		
(Southpoint Glen Apartments)	WR-1150, SUB 4	(10/25/2018)
Interurban Madison, LLC		
(Madison Hall Apartments)	WR-2286, SUB 2	(09/12/2018)
Interurban Wellington, LLP		
(Stadler Place Apartments)	WR-2028, SUB 3	(08/06/2018)
IP9 MF Oaks, LLC		
(Laurel Oaks Apartments)	WR-1990, SUB 1	(09/20/2018)
IP9 MF Springs, LLC		
(Laurel Springs Apartments)	WR-1991, SUB 1	(09/20/2018)
IRT Lenoxplace Apartments Owner, LLC		
(Lenoxplace at Garners Station Apts.)	WR-1713, SUB 4	(11/05/2018)
Ivy Investment III, LLC		
(Oak Court Apartments)	WR-2041, SUB 1	(10/15/2018)
Jetton Apartments, LLC		
(Linden Apartments; The)	WR-2185, SUB 2	(08/22/2018)
John R. Richardson Real Estate IRA, LLC		
(245 Weaverville Hwy. Mobile HP)	WR-1133, SUB 3	(10/09/2018)
Johnston Road Apartments, LLC		
(Element South Apartments)	WR-1849, SUB 3	(08/20/2018)
Jones; John T. & JoAnn Jones		
(Asbury Acres Mobile Home Park)	WR-1677, SUB 4	(10/04/2018)
Junction 1504, LLC		
(Junction 1504 Apartments)	WR-1559, SUB 4	(10/30/2018)
K Colonial, LLC		
(Autumn Trace Apts., Phases 2 & 3)	WR-1943, SUB 6	(08/21/2018)
(Colonial Apartments, Phase 3)	WR-1943, SUB 7	(08/21/2018)
K Partnership, LLC		
(Hampton Downs Apartments)	WR-1631, SUB 4	(08/20/2018)

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Company	Docket No.	Date
KC Realty Investments, LLC		
(Glimmer Mobile Home Park)	WR-950, SUB 21	(10/08/2018)
(Hemlock Court Mobile Home Park)	WR-950, SUB 22	(10/08/2018)
(Oteen Mobile Home Park)	WR-950, SUB 23	(10/08/2018)
(Woodland Heights Mobile Home Park)	WR-950, SUB 24	(10/09/2018)
(Rockola Mobile Home Park)	WR-950, SUB 25	(10/08/2018)
KG Commons, LLC		
(Parkland Commons Apartments)	WR-2011, SUB 3	(09/10/2018)
KG Creek, LLC		
(Cooper Creek Apartments)	WR-2012, SUB 3	(08/28/2018)
Kings Arms, LLC		
(Kings Arms Apartments)	WR-1874, SUB 2	(10/17/2018)
King's Grant Apartments, LLC		
(Ardmore King's Grant Apartments)	WR-2120, SUB 2	(08/02/2018)
Kings Park, LLC		
(Redcliffe at Kenton Place Apts.)	WR-349, SUB 15	(08/22/2018)
Kingswood NC, LLC		
(Kingswood Mobile Home Park)	WR-987, SUB 5	(10/15/2018)
Kip-Hell Homes. Inc.		
(Pine Winds Apartments, Phase I)	WR-341, SUB 12	(08/10/2018)
Kirkwood Place, LLC, et al.		
(Kirkwood Place Apartments)	WR-2466, SUB 1	(08/23/2018)
KIWA, LLC		
(Kingswood Apartments)	WR-1287, SUB 2	(09/24/2018)
Kubeck; Bruce A.		
(Faircrest Mobile Home Park)	WR-310, SUB 39	(10/10/2018)
Lafayette Landing Apts. and Villas, LLC		
(Lafayette Landing Apts. and Villas)	WR-2152, SUB 2	(08/23/2018)
Lake Brandt I, LLC, et al.		
(Lake Brandt Apartments)	WR-2166, SUB 2	(08/31/2018)
Lakeshore Apartments, LLC		
(Lodge at Lakeshore Apts.; The)	WR-649, SUB 10	(08/08/2018)
Lancaster GCI, LLC, et al.		
(Legacy 521 Apartments)	WR-1879, SUB 3	(09/11/2018)
Landings Apartments, LLC; The		
(Landings at Northcross Apts.; The)	WR-2422, SUB 1	(08/28/2018)
LaSalle NC, LLC		
(Duke Manor Apartments)	WR-1286, SUB 7	(07/23/2018)

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Company	Docket No.	Date
Loray Mill Redevelopment, LLC		
(Loray Mill Lofts Apartments)	WR-1615, SUB 3	(08/10/2018)
LSREF3 Bravo (Raleigh), LLC		
(Reserve at Lake Lynn Apartments; The)	WR-1717, SUB 26	(08/13/2018)
(Walnut Creek Apartments)	WR-1717, SUB 27	(08/13/2018)
(Spring Forest Apartments)	WR-1717, SUB 28	(08/13/2018)
(Meadows at Kildaire Apts.; The)	WR-1717, SUB 29	(08/29/2018)
(Oaks at Weston Apartments)	WR-1717, SUB 30	(08/29/2018)
(Copper Mill Apartments)	WR-1717, SUB 31	(08/29/2018)
(Crest Apartments; The)	WR-1717, SUB 32	(10/09/2018)
LWH Ashley Oaks Apartments, LP		
(Ashley Oaks Apartments)	WR-1953, SUB 3	(10/08/2018)
LWH Edgewater Village Apartments, LP		
(Edgewater Village Apartments)	WR-2343, SUB 2	(10/08/2018)
LWH Huntsville Apartments, LP		
(Hunt's View Apartments)	WR-2439, SUB 1	(10/08/2018)
M Realty, LLC		
(Wellington Mobile Home Park)	WR-1040, SUB 6	(07/16/2018)
M Station, LLC		
(M Station Apartments)	WR-1844, SUB 3	(08/16/2018)
MA Ethan Pointe at Burlington, LLC		
(Ethan Pointe Apartments)	WR-1894, SUB 3	(05/14/2018)
(Ethan Pointe Apartments)	WR-1894, SUB 4	(11/08/2018)
M-A Springfield, LLC		
(Springfield Apartments)	WR-2234, SUB 2	(08/22/2018)
MAA TANC, LLC		
(Waterford Forest Apartments)	WR-2496, SUB 1	(09/26/2018)
Madison Apartments, LLC; The		
(Madison Apartments; The)	WR-1703, SUB 2	(08/30/2018)
Mag Hill NC, LLC		
(Hillrock Estates Apartments)	WR-2525, SUB 1	(08/28/2018)
Maggard; David		
(Quiet Hollow Mobile Home Park)	WR-632, SUB 9	(10/09/2018)
Mallard Green, LLC		
(Mallard Green Apartments)	WR-1259, SUB 7	(08/30/2018)

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MAR Fairways, LLC		
(Fairways at Birkdale Apts.; The)	WR-2303, SUB 1	(04/09/2018)
(Fairways at Birkdale Apts.; The)	WR-2303, SUB 2	(12/17/2018)
Marquee Station Acquisition, LLC		
(Village at Marquee Station Apts.; The)	WR-2390, SUB 1	(12/21/2018)
Marsh Euclid Apartments, LLC		
(Lexington Dilworth Apts.; The)	WR-2250, SUB 2	(09/24/2018)
Marsh Realty Company		
(Park Place Apartments)	WR-1154, SUB 26	(09/24/2018)
Mason Andrew NC Partners, LLC		
(Wren Northlake Apartments)	WR-2447, SUB 1	(11/27/2018)
Matthews Cove, LLC		
(Cove at Matthews Apartments)	WR-2284, SUB 1	(08/31/2018)
Mayfaire Apartments, LLC		
(Mayfaire Apartments)	WR-345, SUB 10	(08/08/2018)
MCREF North Hills, LLC		
(Park and Market Apartments)	WR-2510, SUB 1	(09/13/2018)
Meadowlark Acres, LLC		
(Meadowlark Acres Mobile Home Park)	WR-2277, SUB 2	(10/03/2018)
Mebane Operating Company, LLC		
(Carden Place Apartments)	WR-1605, SUB 1	(09/12/2018)
Meeker; Edna W., et al.		
(Ellington Farms Apartments)	WR-2460, SUB 1	(07/23/2018)
MEPT Lake Boone LP		
(Marlowe Lake Boone Apts.; The)	WR-2521, SUB 1	(07/18/2018)
Mercury NoDa Apartments, LLC		
(Mercury NoDa Apartments)	WR-1954, SUB 3	(09/11/2018)
Meridian at Fairfield Park, LLC		
(Meridian at Broad Street Market Apts.)	WR-2409, SUB 1	(09/18/2018)
(Meridian at Fairfield Park Apts.)	WR-2101, SUB 2	(08/13/2018)
Meridian at Harrison Pointe, LLC		
(Meridian at Harrison Pointe Apts.)	WR-1568, SUB 4	(08/10/2018)
Meridian/H.C., LLC		
(Legacy at Meridian Apartments)	WR-1500, SUB 5	(12/21/2018)
Metro 808 Charlotte, LLC		
(Metro 808 Apartments)	WR-1714, SUB 3	(02/12/2018)
(Metro 808 Apartments)	WR-1714, SUB 4	(10/09/2018)

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Company	Docket No.	Date
MLVI Pointe at Crabtree Apartments, LLC		
(Pointe at Crabtree Apartments; The)	WR-1796, SUB 3	(10/23/2018)
Modern Way Owner, LLC		
(Addison at South Tryon Apts.; The)	WR-2248, SUB 1	(11/14/2018)
Morganton Trading Company L.P.		
(Morganton Trading Co. Apartments)	WR-548, SUB 5	(08/15/2018)
Morguard Lodge Apartments, LLC		
(Lodge at Crossroads Apts.; The)	WR-1480, SUB 3	(09/06/2018)
Morguard Perry Point Apartments, LLC		
(Perry Point Apartments)	WR-1521, SUB 2	(09/06/2018)
Moss; Allen H.		
(Crestview II Mobile Home Park)	WR-896, SUB 18	(08/09/2018)
(Maple Terrace Mobile Home Park)	WR-896, SUB 19	(08/09/2018)
Moss Enterprises, Inc. of Asheville		
(Crownpointe Mobile Home Park)	WR-924, SUB 20	(08/09/2018)
(Mosswood/Twin Oaks Mobile HP)	WR-924, SUB 21	(08/09/2018)
Mosteller Apartments, LLC		
(Estates at Legends Apartments; The)	WR-1404, SUB 7	(09/19/2018)
Mountain High Property Management, LLC		
(Becky's Mobile Home Park)	WR-1556, SUB 5	(10/04/2018)
Morehead Apartment Homes, LLC		
(Morehead Apartments; The)	WR-2075, SUB 3	(11/26/2018)
Morreene, LLC		
(Chapel Tower Apartments)	WR-1289, SUB 7	(07/24/2018)
Morrisville Associates, LLC		
(Crabtree Crossing Townhomes Apts.)	WR-879, SUB 6	(01/08/2018)
(Crabtree Crossing Townhomes Apts.)	WR-879, SUB 7	(09/07/2018)
MP Artisan Brightleaf Apartments, LLC		
(Artisan at Brightleaf Apartments)	WR-1478, SUB 6	(09/27/2018)
MP Bridges at Southpoint, LLC		
(Bridges at Southpoint Apartments)	WR-2070, SUB 2	(02/06/2018)
(Bridges at Southpoint Apartments)	WR-2070, SUB 3	(08/16/2018)
MRP North Pointe, LLC		
(Discovery on Broad Apartments)	WR-2533, SUB 1	(10/16/2018)
MRWR, LLC		
(Atrium Apartments)	WR-832, SUB 11	(07/24/2018)
MSS Apartments, LLC		
(Main Street Square Apartments)	WR-936, SUB 3	(09/12/2018)

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Company	Docket No.	Date
NationsProperties, LLC		
(Arbor Crest II Apartments)	WR-821, SUB 5	(08/02/2018)
NC2, LLC		
(Beechwood Apartments)	WR-1730, SUB 4	(09/13/2018)
Nevada Springs, LLC, et al.		
(Marq at Weston Apartments; The)	WR-2159, SUB 3	(12/18/2018)
New Brookstone, LLC		
(Brookstone Apartments)	WR-138, SUB 7	(09/11/2018)
New Haw Creek Associates, LLC		
(New Haw Creek Mews Apts.)	WR-624, SUB 6	(04/17/2018)
New Oaks, LLC; The		
(Oaks Apartments; The)	WR-1818, SUB 3	(09/17/2018)
New Park Ridge Associates, LLC		
(Park Ridge Estates Apartments)	WR-1225, SUB 4	(03/05/2018)
New Willow Ridge Associates, LLC		
(Willow Ridge Apartments)	WR-212, SUB 7	(03/06/2018)
Nicholas; Ruby Lea		
(Woodcrest Mobile Home Park)	WR-249, SUB 12	(02/06/2018)
North Carolina Rental Parks Assoc., Ltd.		
(Whispering Pines Mobile Home Park)	WR-1070, SUB 8	(08/27/2018)
North Chase Apts., LLC		
(North Chase Apartments)	WR-1821, SUB 1	(02/12/2018)
North Elm Investments, LLC		
(Encore North Apartments)	WR-2330, SUB 1	(12/17/2018)
North Estes, LLC		
(Estes Park Apartments)	WR-1288, SUB 2	(09/24/2018)
North Forsyth MHC, LLC		
(North Forsyth Mobile Home Park)	WR-1469, SUB 2	(02/20/2018)
North Wendover Partners, LLC		
(Pines on Wendover Apts.; The)	WR-1998, SUB 3	(08/28/2018)
Northlake Madison Properties, LLC, et al.		
(Madison Square Apartments)	WR-1807, SUB 3	(04/11/2018)
Northland River Birch, LP		
(River Birch Apartments, Phase II)	WR-1258, SUB 6	(09/10/2018)
Northland River Birch I, LLC		
(River Birch Apartments, Phase I)	WR-1248, SUB 6	(09/10/2018)
Northland Windemere, LLC		
(Windemere Apartments)	WR-1369, SUB 6	(08/10/2018)
NP Six Forks, LLC		
(Junction Six Forks Apartments)	WR-1948, SUB 3	(08/21/2018)

WATER RESELLERS – Tariff Revision for Pass-Through *(Continued)*

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Company	Docket No.	Date
NR Holly Crest Property Owner, LLC		
(Holly Crest Apartments)	WR-1816, SUB 5	(10/23/2018)
NR Morningside Property Owner I, LLC		
(Village on Commonwealth Apartments)	WR-1903, SUB 2	(10/09/2018)
NXRTBH Radbourne Lake, LLC		
(Radbourne Lake Apartments)	WR-1722, SUB 3	(03/12/2018)
One Hilltop, LLC		
(Hilltop Mobile Home Park)	WR-1077, SUB 6	(08/20/2018)
ORP EMM, LLC		
(Flats at 55 Twelve Apts.; The)	WR-1769, SUB 3	(12/04/2018)
Oxford City Park Apartments II, LLC		
(City Park View South Apartments)	WR-2383, SUB 1	(10/23/2018)
PAC Citypark View, LLC		
(City Park View Apartments)	WR-2161, SUB 2	(10/23/2018)
Paces Village, LLC		
(Pointe at Irving Park Apts.; The)	WR-1554, SUB 3	(08/09/2018)
Pacifica Mizell, LLC		
(Brannon Park Apartments)	WR-1676, SUB 4	(10/17/2018)
Palladium Park 2, LLC		
(Palladium Park Apartments, Phase II)	WR-2184, SUB 3	(11/08/2018)
Pappas Properties Development, LLC		
(Solis Berewick Apartments)	WR-2391, SUB 2	(11/28/2018)
Park HAT LAP, LLC		
(Park 2300 Apartments)	WR-2252, SUB 1	(08/22/2018)
Park West Village Phase III, LLC		
(District Lofts Apartments)	WR-2226, SUB 2	(08/27/2018)
Parkside REC, LLC		
(Parkside Place Apartments)	WR-2040, SUB 3	(08/27/2018)
Passco Brier Creek DST		
(Carrington at Brier Creek Apts.)	WR-1614, SUB 4	(02/05/2018)
(Carrington at Brier Creek Apts.)	WR-1614, SUB 5	(12/04/2018)
Passco Columns DST		
(Columns at Wakefield Apts.; The)	WR-1633, SUB 3	(10/29/2018)
Patriots Apartments NC, LLC		
(Destination at Union Apartments)	WR-2013, SUB 2	(12/27/2018)
Patriots Pointe Partners, LLC		
(Patriot's Pointe Apartments)	WR-2451, SUB 1	(07/17/2018)

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ORDER APPROVING TARIFF REVISION
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Company	Docket No.	Date
PP TIC Owner, LLC, et al.		
(Marq at Crabtreee Apartments; The)	WR-2052, SUB 4	(12/21/2018)
PR II/Wood Prosperity Apartments, LLC		
(Prosperity Village Apartments)	WR-2398, SUB 1	(10/03/2018)
PR Oberlin Court, LLC		
(Apartments at Oberlin Court; The)	WR-1179, SUB 6	(08/23/2018)
PRCP-Raleigh I, LLC		
(Cedar Springs Apartments)	WR-2392, SUB 2	(11/19/2018)
Preserve Forest, LLC		
(Green Rock Estates Apartments)	WR-2108, SUB 2	(12/05/2018)
PRG Falls at Duraleigh Associates, LLC		
(Falls Apartments; The)	WR-1800, SUB 2	(03/05/2018)
PRG Windsor Square Associates, LLC		
(South Square Townhomes Apts.)	WR-1226, SUB 4	(03/06/2018)
Providence Park Apartments I, LLC		
(Providence Park Apartments)	WR-284, SUB 15	(09/24/2018)
Prudential Insurance Company of America		
(Reserve Apartments; The)	WR-38, SUB 13	(08/31/2018)
Raia NC Exchange Woodbridge, LLC, et al.		
(Dartmouth North Hills Apartments)	WR-2456, SUB 1	(09/26/2018)
RC Acres, LLC		
(Morgan Manor Mobile Home Park)	WR-2136, SUB 1	(04/09/2018)
RCG Grove Park Apartments, LLC		
(Grove Park Apartments)	WR-2313, SUB 3	(09/19/2018)
RCP Briarwood, LLC		
(Briarwood Apartments)	WR-926, SUB 5	(05/29/2018)
Redwood Avent Ferry, LLC, et al.		
(Summit at Avent Ferry Apartments)	WR-2498, SUB 1	(11/14/2018)
Redwood Hamptons Charlotte L.P.		
(Hamptons Apartment Homes; The)	WR-2338, SUB 1	(05/14/2018)
(Hamptons Apartment Homes; The)	WR-2338, SUB 2	(11/08/2018)
REEP-MF Verde NC, LLC		
(North City 6 Apartments)	WR-1087, SUB 8	(08/14/2018)
Regency Place Investors, LLC, et al.		
(Regency Place Apartments)	WR-2323, SUB 1	(08/16/2018)
Renphil II, LLC		
(South Point Apartments)	WR-499, SUB 6	(09/07/2018)
Research Park, LLC		
(Phillips Research Park Apts.)	WR-1470, SUB 3	(10/01/2018)

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Company	Docket No.	Date
RW Hawk Ridge, LLC		
(Hawk Ridge Apartments)	WR-1747, SUB 4	(08/08/2018)
RWJF Associates, LLC		
(Ridgewood Apartments)	WR-835, SUB 6	(09/26/2018)
Sailboat Bay LL, LLC		
(Sailboat Bay Apartments)	WR-2214, SUB 2	(08/15/2018)
Salem Crest Property, LLC		
(Salem Crest Apartments)	WR-2452, SUB 1	(09/12/2018)
Salem Village Apartments, LLC		
(Salem Village Apartments)	WR-446, SUB 12	(09/24/2018)
Sawmill Point Apartments Owner, LLC		
(Sawmill Point Apartments)	WR-2261, SUB 1	(01/29/2018)
SBMF Phase 3, LLC		
(Stillwater at Southbridge Apts., Phase III)	WR-1883, SUB 1	(09/06/2018)
SBV-Greensboro-I, LLC		
(Retreat II Apartments; The)	WR-1471, SUB 14	(08/10/2018)
(Retreat I Apartments; The)	WR-1471, SUB 15	(08/10/2018)
SCG/TBR Venue Owner, LLC		
(Venue Apartments)	WR-1799, SUB 4	(10/30/2018)
Schrader Family Limited Partnership		
(Green Castle Apartments)	WR-980, SUB 44	(08/07/2018)
(Dover Apartments)	WR-980, SUB 45	(08/07/2018)
(Meadows Apartments)	WR-980, SUB 46	(08/07/2018)
(Woodridge Apartments)	WR-980, SUB 50	(08/07/2018)
(Peterson Park Apartments)	WR-980, SUB 51	(08/07/2018)
(Westcliffe Apartments)	WR-980, SUB 52	(08/07/2018)
Schrader; Michael J.		
(Campus West Apartments)	WR-795, SUB 6	(08/07/2018)
Schrader Properties, LLC		
(Campus Courtyard Apartments)	WR-1334, SUB 6	(08/06/2018)
SDGMebane, LLC		
(119 South Apartments)	WR-2346, SUB 1	(08/08/2018)
Seaforth NC Partners, LLC		
(Hamptons at RTP Apartments)	WR-2131, SUB 2	(11/27/2018)
Seagrove Village MHP, LLC		
(Seagrove Village Mobile Home Park)	WR-1297, SUB 4	(10/15/2018)
SG Ansley at Roberts Lake, LLC		
(Ansley at Roberts Lake Apts.)	WR-2325, SUB 1	(12/05/2018)

<u>**WATER RESELLERS – Tariff Revision for Pass-Through**</u> *(Continued)*

ORDER APPROVING TARIFF REVISION
<u>*Orders Issued*</u> *(Continued)*

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Company	Docket No.	Date
South LaSalle Apartments, LLC		
(Heights at LaSalle Apts.; The)	WR-1629, SUB 4	(07/25/2018)
South Square Owner, LLC		
(Alden Place at South Square Apts.)	WR-1387, SUB 6	(12/04/2018)
Southbridge Multifamily, LLC		
(Stillwater at Southbridge Apts.)	WR-1390, SUB 2	(09/04/2018)
Southern Village Apartments, LLC		
(Southern Village Apartments)	WR-338, SUB 9	(11/05/2018)
Southline Apartments, LLC		
(Solis Southline Apartments)	WR-2326, SUB 1	(11/28/2018)
Southport Heather Ridge, LLC		
(Heather Ridge Apartments)	WR-1082, SUB 6	(07/02/2018)
Southwood Realty Company		
(Catawba Apartments)	WR-910, SUB 27	(09/26/2018)
(Quail Woods Apartments)	WR-910, SUB 28	(10/11/2018)
(Azalea Apartments)	WR-910, SUB 30	(10/11/2018)
(Landings Apartments; The)	WR-910, SUB 31	(10/11/2018)
(Carriage House Apartments)	WR-910, SUB 34	(10/11/2018)
Sovereign Development Company, LLC		
(Willow Woods Apartments)	WR-784, SUB 9	(10/16/2018)
Spectrum South End, LLC		
(Spectrum South End Apartments)	WR-1011, SUB 7	(05/30/2018)
SRC Candler, LLC		
(Haven Apartments; The)	WR-2337, SUB 2	(10/10/2018)
SRC Dilworth, Inc.		
(Dilworth Apartments)	WR-2195, SUB 2	(09/24/2018)
SRC Northwinds, Inc.		
(Northwinds Apartments)	WR-1254, SUB 7	(08/06/2018)
Station Nine Owner, LLC		
(Station Nine Apartments)	WR-2567, SUB 1	(10/09/2018)
Steele Creek Apts. Property Owner, LLC		
(Park at Steele Creek Apartments)	WR-1332, SUB 3	(09/10/2018)
Stephens Pointe, LLC		
(Stephens Pointe Apartments)	WR-1746, SUB 2	(07/23/2018)
Sterling Forest Associates, LLC		
(Vert at Six Forks Apartments)	WR-1983, SUB 2	(02/19/2018)
(Vert at Six Forks Apartments)	WR-1983, SUB 3	(09/20/2018)
Sterling Forest, LLC		
(Forest Apartments; The)	WR-2230, SUB 2	(09/04/2018)

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Company	Docket No.	Date
Town & Country Mobile Home Park, LLC		
(Town and Country Mobile HP)	WR-2255, SUB 2	(08/10/2018)
Town Square West, LLC		
(Biltm ore Park Town Square Apts.)	WR-862, SUB 5	(10/16/2018)
TP 1100 South Blvd., LLC		
(1100 South Apartments)	WR-1817, SUB 4	(08/16/2018)
TR Brier Creek, LLC		
(Jamison at Brier Creek Apts.; The)	WR-1524, SUB 3	(03/13/2018)
(Jamison at Brier Creek Apts.; The)	WR-1524, SUB 4	(08/13/2018)
Tradition at Stonewater Apartments, LLC		
(Tradition at Stonewater Apartments)	WR-1723, SUB 4	(10/22/2018)
Treybrooke, LLC		
(Treybrooke Apartments)	WR-824, SUB 5	(07/24/2018)
Triangle Ashbrook, Inc.		
(Ashbrook Village Apartments)	WR-2363, SUB 1	(10/11/2018)
Triangle Grand Summit, LLC		
(Grand Summit Apartments)	WR-2364, SUB 1	(08/07/2018)
Triangle Mills Creek, Inc.		
(Mills Creek Apartments)	WR-1580, SUB 2	(10/10/2018)
Triangle Palisades of Asheville, Inc.		
(Palisades Apartments)	WR-1787, SUB 4	(09/24/2018)
Triangle Real Estate Brentwood, LLC		
(Brentwood Chase Apartments)	WR-2253, SUB 1	(10/11/2018)
Triangle Real Estate of Gastonia, LLC		
(Legacy of Abbington Place Apts.)	WR-1125, SUB 48	(08/20/2018)
(Avalon at Sweeten Creek Apts.)	WR-1125, SUB 49	(09/24/2018)
(Palisades at Legacy Oaks Apts.; The)	WR-1125, SUB 50	(10/10/2018)
(Bluff Ridge Apartments)	WR-1125, SUB 51	(10/10/2018)
(Lake Mist Apartments)	WR-1125, SUB 52	(10/10/2018)
(Woodbridge Apartments)	WR-1125, SUB 53	(10/10/2018)
(Pinetree Apartments)	WR-1125, SUB 54	(10/10/2018)
(Huntersville Commons Apts.)	WR-1125, SUB 55	(10/10/2018)
(Arborgate Apartments)	WR-1125, SUB 56	(10/10/2018)
(Eagle's Walk Apartments)	WR-1125, SUB 57	(10/10/2018)
(Hudson Woods Apartments)	WR-1125, SUB 58	(10/10/2018)
Trinity Commons Apartments, LLC		
(Colonial Grand at Trinity Commons Apts.)	WR-415, SUB 10	(02/16/2018)
(Colonial Grand at Trinity Commons Apts.)	WR-415, SUB 11	(09/26/2018)

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Company	Docket No.	Date
Trinity Properties, LLC		
(Georgetown Apartments)	WR-1696, SUB 20	(07/30/2018)
(Campus Walk Apartments)	WR-1696, SUB 22	(07/30/2018)
Trotter Company		
(Elmsley Grove Apartments)	WR-593, SUB 5	(08/13/2018)
TS Brier Creek, LLC		
(Waterstone at Brier Creek Apts.)	WR-1620, SUB 4	(12/21/2018)
TS Creekstone, LLC		
(Creekstone at RTP Apartments)	WR-1461, SUB 5	(01/08/2018)
TS Westmont, LLC		
(Westmont Commons Apartments)	WR-1462, SUB 5	(01/22/2018)
TSG Matthews, LLC		
(Matthews Lofts Apartments)	WR-2217, SUB 2	(08/31/2018)
Tyler's Ridge Apartments, LLC		
(Tyler's Ridge Apartments)	WR-1507, SUB 3	(08/27/2018)
Tyler's Ridge Phase II, LLC		
(Tyler's Ridge Apartments, Phase II)	WR-2464, SUB 1	(08/31/2018)
Umstead Raleigh Investors, LLC		
(Seasons at Umstead Apts.; The)	WR-1772, SUB 3	(11/19/2018)
University City Community, LLC		
(Blu at Northline Apartments)	WR-2462, SUB 1	(11/08/2018)
Village at Broadstone Station I, LLC, et al.		
(Village at Broadstone Station Apts.)	WR-1601, SUB 2	(10/05/2018)
Village at Carver Falls II, LLC; The		
(Village at Carver Falls Apts.; The)	WR-563, SUB 5	(08/14/2018)
Village Creek West Properties I, LLC		
(Village Creek West Apartments)	WR-713, SUB 7	(10/08/2018)
Village Gate Partners, LLC		
(Village Gate Apartments)	WR-934, SUB 6	(08/22/2018)
Village (Locust), LLC; The		
(Village Apartments; The)	WR-1008, SUB 3	(09/27/2018)
Villas at Granite Ridge, LLC		
(Villas at Granite Ridge Apts.; The)	WR-1788, SUB 4	(11/13/2018)
Villas at Murrayville, LLC		
(Hawthorne at Murrayville Apts.)	WR-1221, SUB 4	(08/28/2018)
Vinings at Morehead, LLC		
(Vinings at Wildwood Apartments)	WR-1216, SUB 4	(10/01/2018)
VR Chatham Lofts Limited Partnership		
(Town Station Lofts Apartments)	WR-2423, SUB 1	(08/23/2018)

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Company	Docket No.	Date
VR Chatham Pointe Limited Partnership		
(Town Station Apartments)	WR-2424, SUB 1	(07/25/2018)
VTT Charlotte, LLC		
(Woodland Estates Apartments)	WR-1506, SUB 4	(10/11/2018)
Vyne on Central Partners, LLC		
(Vyne on Central Apartments; The)	WR-2204, SUB 3	(10/03/2018)
Wafra Invest Loft 135, LP		
(Loft 135 Apartments)	WR-2305, SUB 2	(10/08/2018)
Wake Forest Apartments, LLC		
(Aston Apartments)	WR-1510, SUB 4	(11/07/2018)
Walden Court, Inc.		
(Walden Court Apartments)	WR-1878, SUB 3	(08/16/2018)
Water Garden Village, LLC		
(Water Garden Village Apartments)	WR-1315, SUB 6	(08/09/2018)
Water Oak NC Partners, LLC		
(Regency Apartments; The)	WR-1850, SUB 3	(11/26/2018)
Waterford at the Park DE, LLC		
(Waterford at the Park Apartments)	WR-1654, SUB 5	(08/21/2018)
Waterford Lakes NC Partners, LLC		
(Anson at the Lakes Apartments)	WR-1854, SUB 2	(11/26/2018)
Waterford Valley NC Partners, LLC		
(Arboretum at Southpoint Apts.)	WR-2183, SUB 2	(11/27/2018)
Waverly Apartments, LLC		
(Waverly Apartments; The)	WR-1293, SUB 7	(08/06/2018)
Waypoint Barrington Owner, LLC, et al.		
(Barrington Place Apartments)	WR-2333, SUB 2	(08/28/2018)
Waypoint Stone Hollow Owner, LLC		
(Reserve at Stone Hollow Apartments)	WR-1611, SUB 5	(08/28/2018)
WB Tatton, LLC, et al.		
(Weirbridge Village Apartments)	WR-2429, SUB 1	(08/22/2018)
WDF-3 Wood Oberlin Owner, LLC		
(616 at the Village Apartments)	WR-2127, SUB 1	(10/03/2018)
Wellington West, LLC		
(Poplar Terrace Mobile Home Park)	WR-2154, SUB 1	(08/21/2018)
Wendover at River Oaks, LLC		
(Wendover at River Oaks Apts.)	WR-1975, SUB 3	(08/10/2018)
Wendover Axcess Apartments, LLC		
(Wendover Axcess Apartments)	WR-2105, SUB 1	(11/13/2018)

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Company	Docket No.	Date
West Morgan, LLC		
(927 West Morgan Apartments)	WR-1428, SUB 5	(12/03/2018)
West 1st Street Apartments Investors, LLC		
(Museum Tower Apartments)	WR-2347, SUB 1	(08/08/2018)
Westdale Arrowhead Crossing NC, LLC		
(Arrowhead Crossing Apartments)	WR-634, SUB 11	(10/15/2018)
Westdale Brentmoor, LLC		
(Brentmoor Apartments)	WR-1317, SUB 6	(10/01/2018)
Westdale Chase on Monroe NC, LLC		
(Chase on Monroe Apartments)	WR-635, SUB 11	(10/15/2018)
Westdale NC Summit Creek, Ltd.		
(Johnston Creek Crossing Apts.)	WR-826, SUB 10	(10/16/2018)
Westdale Peppertree, Ltd.		
(Peppertree Apartments)	WR-815, SUB 10	(10/16/2018)
Westdale Poplar Place, LLC		
(Poplar Place Apartments)	WR-816, SUB 7	(11/07/2018)
Westdale Sabal Point NC, LLC		
(Sabal Point Apartments)	WR-636, SUB 11	(10/18/2018)
Westdale Willow Glen NC, LLC		
(Willow Glen Apartments)	WR-633, SUB 11	(10/17/2018)
Westridge Place, LLC		
(Westridge Place Apartments)	WR-637, SUB 6	(10/15/2018)
Westridge Village, LLC		
(Westridge Village Apartments)	WR-1142, SUB 4	(12/21/2018)
WF-ARK NCMF Apartments, LLC		
(Cadence Music Factory Apartments)	WR-2296, SUB 1	(11/19/2018)
WGL Associates, LLC		
(Pepperstone Apartments)	WR-1940, SUB 3	(08/08/2018)
Wheeling Village MHC, LLC		
(Wheeling Village Mobile HC)	WR-2434, SUB 1	(10/15/2018)
Wilkinson High Point I, LLC		
(Fox Hollow Apartments)	WR-1670, SUB 3	(12/21/2018)
Wilkinson High Point II, LLC		
(Eastchester Ridge Apartments)	WR-1762, SUB 4	(12/21/2018)
Willow Run, LLC		
(Willow Run Apartments)	WR-1827, SUB 3	(08/20/2018)
Wilmington Gallery I, LLC		
(Element Barclay Apartments)	WR-2317, SUB 1	(12/27/2018)

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Company	Docket No.	Date
Windridge Apartments, LLC		
(Windridge Apartments)	WR-1655, SUB 4	(08/29/2018)
WMCi Raleigh I, LLC		
(Bexley at Preston Apartments)	WR-327, SUB 13	(07/30/2018)
WMCi Raleigh II, LLC		
(Bexley Park Apartments)	WR-317, SUB 13	(07/30/2018)
WMCi Raleigh III, LLC		
(Bexley at Brier Creek Apartments)	WR-754, SUB 14	(07/30/2018)
WMCi Raleigh IV, LLC		
(Bexley at Heritage Apts.)	WR-803, SUB 9	(07/25/2018)
WMCi Raleigh V, LLC		
(Bexley at Carpenter Village Apts.)	WR-949, SUB 10	(07/30/2018)
WMCi Raleigh VI, LLC		
(Bexley at Triangle Park Apartments)	WR-1311, SUB 6	(07/30/2018)
WMCi Raleigh VII, LLC		
(Bexley Panther Creek Apartments)	WR-1372, SUB 6	(07/30/2018)
WMCi Raleigh VIII, LLC		
(Bristol at Park West Village Apts.; The)	WR-1693, SUB 4	(07/30/2018)
WMCi Raleigh IX, LLC		
(Belmont Apartments; The)	WR-1754, SUB 4	(07/30/2018)
WMCi Charlotte I, LLC		
(Bexley Commons at Rosedale Apts.)	WR-213, SUB 16	(08/06/2018)
WMCi Charlotte II, LLC		
(Bexley Creekside Apartments)	WR-230, SUB 15	(08/07/2018)
WMCi Charlotte III, LLC		
(Bexley at Lake Norman Apts.)	WR-258, SUB 15	(08/07/2018)
WMCi Charlotte IV, LLC		
(Bexley Crossing at Providence Apts.)	WR-269, SUB 15	(08/07/2018)
WMCi Charlotte V, LLC		
(Bexley at Springs Farm Apts.)	WR-340, SUB 14	(08/07/2018)
WMCi Charlotte VII, LLC		
(Bexley at Davidson Apartments)	WR-392, SUB 13	(08/07/2018)
WMCi Charlotte VIII, LLC		
(Bexley at Matthews Apartments)	WR-466, SUB 13	(08/07/2018)
WMCi Charlotte IX, LLC		
(Bexley Greenway Apartments)	WR-467, SUB 13	(08/07/2018)
WMCi Charlotte X, LLC		
(Bexley at Harborside Apartments)	WR-638, SUB 11	(08/07/2018)

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WMCi Charlotte XI, LLC		
(Bexley Steelecroft Apartments)	WR-1117, SUB 8	(08/06/2018)
WMCi Charlotte XII, LLC		
(Bexley Cloisters at Steelecroft Apts.)	WR-1136, SUB 7	(08/06/2018)
WMCi Charlotte XV, LLC		
(Cielo Apartments)	WR-1486, SUB 5	(08/06/2018)
Woodland Estates Mobile Home Park, LLC		
(Woodland Estates Mobile Home Park)	WR-1863, SUB 3	(09/05/2018)
WOP Cornerstone, LLC		
(Cornerstone Apartments)	WR-1905, SUB 3	(10/22/2018)
WRPV XII Addison Park Charlotte, LLC		
(Addison Park Apartments)	WR-2035, SUB 3	(10/17/2018)
Wynslow Park, LLC		
(Gardens at Wynslow Park Apts.)	WR-128, SUB 8	(08/16/2018)
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