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.[11]

[11] 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.

<u>Summary of Testimony Received in Franklin</u>

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.

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.[12] A component of cost of service as important as return on investment is test year revenues.[13] 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.

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

[12] N.C. Gen. Stat. § 62-133(c)

[13] N.C. Gen. Stat. § 62-133(b)(3).

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[14] 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, 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

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

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.[15] 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. When regulatory risk is high, the cost of capital goes up.

2013 DEC Rate Order, p. 37 (emphasis added).

[15] 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.

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 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.[16] 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 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.

[16] 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.

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.[17] 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

[17] The Stipulation provides that the Company reserves the right to request an extension of the May 31, 2020 date.

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 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.[18]

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

[18] 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 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.").

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.[19] 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.][20] DEP classified 95.9% of secondary poles in FERC Account 364 as customer related in its most recent rate case.[21]

Tr. Vol. 20, pp. 82-83.

[19] 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.

[20] 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.

[21] 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).

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.[22] 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.

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

[22] DEC Form E-1, Item 45D, p. 5.

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 Coughlan 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.[23] 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.

[23] 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.

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, 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.

Standby Service

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[24] 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;
- 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,

[24] SAIDI and SAIFI are metrics that reflect the averages duration and frequency of power outages.

or $11.3 million on a North Carolina retail basis,[25] 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 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

[25] 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.

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,[26] however, there are a few changes to witness Saillor's

[26] 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.

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 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.

<u>Summary of AMI Testimony</u>

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. <u>Id.</u> at 323. In 2016, the Company spent $73.9 million on new AMI meters across the system in North and South Carolina. <u>Id.</u> 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. <u>Id.</u> 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. <u>Id.</u> 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. <u>Id.</u> 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. <u>Id.</u> at 89-90. Witness Floyd also testified regarding customers who opt-out of having an AMI meter installed. <u>Id.</u> 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.[27] 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.

[27] The Commission has taken judicial notice of all filings in Docket No. E-100, Sub 147. Tr. Vol. 18, p. 402.

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 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)[28], (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

[28] 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.

10-year Power Forward plan. 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.[29]

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

[29] 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.

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 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.

<u>Public Staff testimony</u>

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.[30]

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.

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

[30] 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.

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.[31]

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.

[31] See Senate Bill 619 (2017).

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.

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[32] 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.

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.

[32] On April 2, 2018, DEC filed a late-filed exhibit containing such plans for 2018 and 2019 only.

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.[33] 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,

[33] 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.

is necessary to determine whether a Grid Rider would affect DEC's cost of equity or rate of return on equity.

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.