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Nov 04 2020

NORTH CAROLINA
PUBLIC STAFF
UTILITIES COMMISSION

November 4, 2020

Ms. Kimberley A. Campbell, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

Re: Docket No. E-7, Sub 1213 – Application for Approval of Proposed Prepaid Advantage Program; Docket No. E-7, Sub 1214 – Application for General Rate Case; and E-7, Sub 1187 – Petition of Duke Energy Carolinas, LLC for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego

Dear Ms. Campbell:

Attached for filing is the Public Staff's Proposed Additional Findings, Evidence, and Conclusions in the above-referenced docket.

The Public Staff is filing additional findings, evidence and conclusions regarding coal ash related issues under separate cover.

By copy of this letter, I am forwarding a copy to all parties of record by electronic delivery.

Sincerely,

<u>Electronically submitted</u>
s/ Dianna W. Downey
Chief Counsel
dianna.downey@psncuc.nc.gov

DWD/cla

Attachment

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1213
DOCKET NO. E-7, SUB 1214
DOCKET NO. E-7, SUB 1187

DOCKET NO. E-7, SUB 1213 In the Matter of Application for Approval of Proposed Prepaid Advantage Program DOCKET NO. E-7, SUB 1214 In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina DOCKET NO. E-7, SUB 1187 In the Matter of Application of Duke Energy Carolinas, LLC for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego	))	**PUBLIC STAFF'S PROPOSED ADDITIONAL FINDINGS, EVIDENCE, AND CONCLUSIONS**

ADDITIONAL FINDINGS OF FACT

Hydro Station Sale

1. It is just and reasonable in this proceeding to adopt the Public Staff's recommendation to amortize the Company's loss on the sale of hydro station units based on the overall remaining depreciable life of the assets of 20 years, as opposed to seven years as recommended by the Company, as this amortization period reasonably spreads the loss on disposal over the years in which customers would have otherwise been served by the assets disposed of.

Depreciation

2. It is just and reasonable to restore the depreciation rates on the Allen and Cliffside power stations to the depreciation rates approved in DEC's last general rate case.

3. Use of a 10% contingency for future "unknowns" in the estimate of future terminal net salvage costs is reasonable in this case.

4. Use of an interim net salvage percentage of zero for Accounts 342, 343, 344, 345, and 346 is reasonable in this case.

5. Use of an average service life of 17 years for the new AMI meters is reasonable in this case.

6. It is reasonable and appropriate to approve the use of the Public Staff's proposed depreciation rates as shown on Public Staff witness Roxie McCullar's Exhibit RMM-1.

GIP Cost Allocation Study

7. Evidence presented in this proceeding indicates that the Company relied upon cost benefit analyses (CBA) to quantify and justify certain components of its Grid Improvement Program (GIP).

8. Evidence presented in this proceeding further indicates that net benefits derived from the CBAs for some of the transmission and distribution assets associated with the Company's GIP may be disproportionally related to the way GIP transmission and distribution plant is currently allocated.

9. Though the National Association of Regulatory Utility Commissioners' (NARUC) Electric Utility Costs Allocation Manual has been and remains a relevant and important resource for the calculation and allocation of electric utility cost of service, the approach to cost allocation suggested by the Regulatory Assistance Project's (RAP) January 2020 Electric Cost Allocation Manual, particularly as it relates to GIP costs, is worthy of consideration.

10. It is reasonable for the Company, in consultation with the Public Staff and other interested stakeholders, to study the allocation of GIP investments based on the realized benefits of those investments, and report its findings no later than the filing of its next general rate case.

CIGFUR Stipulation AND EDIT Return

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

12. It is premature for DEC to agree in advance to use a specific allocation factor or methodology to allocate deferred GIP costs among the customer classes in the next general rate case. At the time DEC seeks to recover its GIP costs (deferred or otherwise), DEC shall propose an appropriate method to allocate GIP costs.

13. It is inappropriate to refund unprotected Excess Deferred Income Taxes and deferred revenue giveback overpaid by customers through the EDIT rider on a uniform cent/kWh basis rather than as a levelized EDIT credit by specific customer-class divided by the adjusted class' test year sales.

14. In regard to the provision of the CIGFUR Stipulation related to the adjustment of peak demands used in the Company's cost of service studies to allocate certain demand-related costs is accepted, it is appropriate for the Company to adjust all peak demand hours incorporated into the peak demand inputs used in various COSS methodologies, but only to the extent that the Company actually realized a level of demand reduction based on it calling on or activating a demand reduction resource (DSM program or interruptible load program) for the specific hour under consideration. If an adjustment is made, the Company shall impute the total amount of available resource for all customer classes as appropriate as if the entire portfolio of DSM and interruptible resources were called.

15. The Commission declines to require the Company to propose the uniform percentage average bill adjustment methodology in its 2021 and 2022 annual fuel cost proceedings.

16. The Commission declines to approve the provision of the CIGFUR Stipulation requiring DEC to propose the Minimum System Method (MSM) for determining classification of distribution costs for specific rate schedules in a future proceeding. Instead, the appropriateness of use of the MSM shall be considered in the comprehensive rate study.

17. It is appropriate for the Company to include in its comprehensive rate study a discussion of the various rate schedules as discussed in Section E of the CIGFUR Stipulation.

18. Based upon all of the evidence in the record, the Commission accepts in part, the CIGFUR Stipulation as modified herein, and finds that those provisions that are accepted are just and reasonable to the customers of DEC and to all parties to this proceeding, and serve the public interest. In addition, the CIGFUR Stipulation as modified is entitled to substantial weight and consideration in the Commission's decision in this docket.

Commercial Group/Harris Teeter Stipulations

19. It is inappropriate to require the Company to recover its GIP-related costs solely through demand rates in OPT-V or any other rate schedule that includes a demand rate.

20. For purposes of setting rates in this proceeding, the Commission finds reasonable the terms related to the on- and off-peak energy rates that would apply to OPT-VSS. However, the Company shall study this rate in the comprehensive rate study and propose all appropriate adjustments in the next proceeding.

21. Based upon all of the evidence in the record, the Commission accepts in part, the CG/HT Stipulations as discussed herein, and finds that those provisions that are accepted are just and reasonable to the customers of DEC and to all parties to this proceeding, and serve the public interest. In addition, the CG/HT Stipulations as modified are entitled to substantial weight and consideration in the Commission's decision in this docket.

Credit Metrics

22. N.C.G.S. 62-133 sets forth the factors to be considered by the Commission in setting rates for public utilities.

23. N.C.G.S. 62-133(a) states in fixing rates the Commission shall fix such rates as shall be fair to both the public utilities and to customers.

24. N.C.G.S. 62-133(d) states the Commission shall consider all other material facts of record that will enable the Commission to determine reasonable and just rates.

25. There is no requirement in N.C.G.S. 62-133 that the Commission consider the utility's credit ratings or stock price in fixing just and reasonable rates.

26. While the Commission's decision must consider the impact its decision will have on the utility's ability to access capital markets, it is the responsibility of the utility's management to prudently manage the utility in a manner that supports the utility's credit ratings and the stock price.

27. The rates fixed by this Commission will not harm the ability of Duke Energy and its subsidiaries, through prudent management, to access the capital markets on reasonable terms.

28. The rates fixed by this order are fair to both DEC and customers and produce just and reasonable rates.

Revenue Requirement

29. It is just and reasonable to adopt the base revenue requirement recommended by the Public Staff in Public Staff witness Boswell's Second Supplemental and Stipulation Exhibit 1 of $290,049,000.

30. After giving effect to the approved Public Staff Partial Stipulations and the Commission's decision on contested issues, the annual revenue requirement of $290,049,000 will allow the Company a reasonable opportunity to earn the 7.042% rate of return on its rate base that the Commission has found just and reasonable.

31. The appropriate base revenue requirement for the first two years should be reduced by the State EDIT Rider and the Deferred Federal provisional EDIT Rider decrements of $83.054 million each year.

32. The appropriate base revenue requirement for the first five years should be reduced by the unprotected Federal EDIT Rider decrement of $240.875 million each year, and will be recalculated by the Company to remove the actual amounts refunded to ratepayers during the period interim rates were in effect.

33. The total revenue requirement for years 1 and 2, as reflected in Public Staff Boswell's Second Supplemental and Stipulation Exhibit 1, is ($33,880,000). This amount is subject to the final actual Federal unprotected EDIT remaining to be refunded after the amounts actually refunded in interim rates.

34. The total revenue requirement for years 3 through 5, as reflected in Public Staff Boswell's Second Supplemental and Stipulation Exhibit 1 is $49,174,000. This amount is subject to the final actual Federal unprotected EDIT remaining to be refunded after the amounts actually refunded in interim rates.

35. Since the Company will need to provide updated Federal unprotected EDIT amounts to refund to ratepayers due to the return of some of the EDIT in interim rates, DEC should recalculate and file the annual revenue requirement in the same format as Boswell Second Supplemental and Stipulation Exhibits 1, 2, and 3, with the Commission within ten days of the issuance of this Order, consistent with the findings and conclusions of this Order. The Company should work with the Public Staff to verify the accuracy of the filing. DEC should file schedules summarizing the gross revenue and the rate of return that the Company should have the opportunity to achieve based on the Commission's findings and determinations in this proceeding.

ADDITIONAL EVIDENCE AND CONCLUSIONS

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

[Hydro Station Sale]

The evidence supporting this finding and conclusion is contained in the Application and the accompanying E-1, the entire record of Docket No. E-7, Sub 1181, the testimony of Company witness Jane McManeus, and the testimony of Public Staff witness Michelle Boswell.

Company witness McManeus, in her direct testimony, stated that she made an adjustment to remove test period operating expenses and rate base amounts related to five hydro stations sold on August 16, 2019. The sale of the facilities and the transfer of the related certificates of public convenience and necessity were approved by the Commission in Docket Nos. E-7, Sub 1181 (Sub 1181); SP-12478, Sub 0; and SP-12479, Sub 0. In addition, the Commission, in those dockets, approved the establishment of a regulatory asset for the estimated loss on disposition of the facilities, and ordered that the amortization of the regulatory asset begin at the time the sale is closed. Accordingly, the Company's adjustment also included a proposed amortization of the estimated loss on the sale over a period of time, in this case a 7-year period. According to witness McManeus, this period was selected to closely align the revenue requirement amount associated with the loss on the sale with the revenue requirement amount associated with ownership of the facilities. (Tr. vol. 11, 485.) Witness McManeus also went on to say in her rebuttal testimony that she believed the Company's recommended 7-year period was fair, because "The revenue requirement resulting from the annual amortization expense using the 7-year amortization period as proposed by the Company closely aligns with the amount of revenue requirement associated with test period annual O&M expense and annual depreciation expense of the hydro units being sold, resulting in minimal change to existing rates." (Tr. vol. 11, 523.) During cross-examination by the Public Staff, witness McManeus indicated that the 20-year amortization period temporarily approved by the Commission in Sub 1181, which is the same as proposed by the Public Staff in this general rate case, would produce lower rates for customers than the 7-year period proposed by the Company. (Tr. vol. 15, 121, 124.)

Public Staff witness Boswell testified that she adjusted the amortization period for the loss on the sale of the hydro units to the overall remaining depreciable life of the assets of 20 years. Witness Boswell noted that in the present rate case Application, DEC recommended an amortization period of seven years, with the purpose of keeping the overall revenue requirement for the units the same as before the sale occurred.

Witness Boswell also noted that in its filing for deferral accounting in Sub 1181, the Company asserted that through the transaction, the facilities would continue to serve the customers with clean renewable energy, but at a lower cost. Additionally, the cost benefit analysis provided by the Company in the above referenced docket was based on 20-year costs to maintain and operate. (Tr. vol. 17, 257.)

As the Public Staff stated in its comments dated September 4, 2018 in the Sub 1181 docket, and in its testimony filed in the same docket on January 18, 2019, the amortization period for the regulatory asset should be set at 20 years, which is comparable to the period of time over which the facilities would have been depreciated if they had remained in service. At the time of the comments, the average remaining life of the facilities was 22.49 years. As of the end of 2019, the remaining depreciable life is 19.95 years. (Id.)

Witness McManeus was asked during cross-examination whether customers would experience a decrease in rates in the present proceeding if the loss on the sale of the hydro units were amortized over 20 years as proposed by the Public Staff, as opposed to 7 years. Witness McManus responded that if you amortize something over seven years, you get a higher amortization amount than you do if you amortize it over 20 years. (Tr. vol. 15, 124.) Witness McManeus further testified that the seven year period was “backed into,” taking a bit of guidance from the Commission's order in Sub 1181. In that order, when the Commission approved the deferral of the loss, they also indicated that the amortization amount should be equal to the depreciation expense; and therefore there was rate neutrality. (Tr. vol. 15, 123-124.)

During the cross-examination of witness McManeus, counsel for the Public Staff requested the Commission to take judicial notice of the Commission’s Order in the Sub 1181 docket, which request was granted. (Tr. vol. 15, 120.)

Based on the foregoing and the entire record herein, the Commission finds that it is appropriate in this proceeding to adopt the recommendation of the Public Staff. In reaching this conclusion, the Commission gives significant weight to Public Staff witness Boswell’s testimony and the record of and the Commission’s Order issued in the Sub 1181 docket. It is undisputed that the purpose of the sale of the hydro units in question was to enable the Company to supply its customers with electric service using least-cost principles. The Commission did order in Sub 1181 that the Company amortize the loss on sale (i.e., the “stranded cost” of the hydro facilities) over the 20-year remaining depreciation period; however, the rationale underlying this decision was based on the fact that the Company was already recovering the plants’ costs in its rates based on that period. However, in its Order, the Commission did not recommend rate neutrality for the long term, but rather ordered that the amortization period for the remaining regulatory asset and the question of whether it should earn a return would be decided in DEC's next general rate case.

The current general rate case presents the Commission with a different situation, one in which the rates can be changed to reflect a fair and reasonable distribution of the net benefits of the hydro sale. The Commission concludes that amortizing the stranded costs over a seven-year period in this case will not reflect a fair and reasonable distribution. Amortizing the stranded costs, recovery of which reduces the net benefits to be enjoyed by the customers, over a 7-year period rather than a 20-year period unreasonably skews the benefits toward customers in later years, at the expense of customers in earlier years.

The Commission finds that the Company has not presented evidence in the present case that the amortization of the deferral over a seven year period provides ratepayers with the reasonable benefits of the sale and deferral presented in Sub 1181. The Commission approved the deferral as it provided both a benefit to the ratepayers and the Company. The Commission instead finds and concludes that a 20-year amortization period results in a more fair distribution of benefits over the years that the overall transaction is expected to produce net benefits, and thus concludes that the 20-year period as recommended by the Public Staff should be approved in this proceeding.

Therefore, based on the foregoing, the Commission finds that the amortization period for the loss on the sale of hydro units should be set based on the overall remaining depreciable life of the assets of 20 years.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

[Depreciation of Allen and Cliffside Power Stations]

The evidence supporting this finding and conclusion is contained in the Application and the accompanying E-1, the testimony of Company witnesses Jane McManeus and John Spanos, and the testimony of Public Staff witnesses Michelle Boswell and Dustin Metz.

Public Staff witness Metz testified that the Company had requested to accelerate the depreciation of certain coal-fired generating units in the present rate case. These retirement dates are earlier than shown in DEC's 2018 Integrated Resource Plan (IRP)[1] and 2019 Update[2] filed on September 3, 2019 (less than a month before it filed the general rate case). Witness Metz further testified that the Company's IRP proceeding is the appropriate venue for a thorough review of early, or any, generation retirements.

Public Staff witness Boswell noted that the Company planned to retire Units 4 and 5 of the Allen Power Station in 2024 and Unit 5 of the Cliffside Power Station in 2026, and recommended a five-year depreciation rate for the plants. Witness Boswell, however, recommended that Public Staff witness McCullar restore the depreciation rate of these units to the depreciation rates approved in the Company's last general rate case in Docket No. E-7, Sub 1146. (Tr. vol. 17, 245.)

Witness Boswell testified that her recommendations regarding the rate change were based on the following reasons: 1) although the Company has stated

[1] Docket No. E-100, Sub 157.

[2] Id.

in its testimony that it intends to retire these plants, it has not presently done so; 2) the Public Staff has consistently recommended leaving the depreciation rates set at the original retirement date of the plant, and, at the date of actual physical retirement, any remaining net book value be placed in a regulatory asset account and amortized over an appropriate period, to be determined in a future general rate case; and 3) the Public Staff believes it is appropriate to continue this consistent treatment of retired plants in the present case. (Id.)

Company witness McManeus stated that the Company disagreed with the Public Staff's adjustment. Company witness Spanos testified that as a matter of principle, the concept witness Boswell sets forth does not comport with the USOA or with generally accepted depreciation principles. Witness Spanos further stated that while the Public Staff may have taken this position in the past, it is inequitable by definition. Any of the costs that would be placed in a regulatory asset account and amortized over a given period will be recovered after a facility is retired. The Public Staff's proposal will, by design, result in intergenerational inequity. (Tr. vol. 22, 200-201.)

Upon cross-examination, witness Spanos accepted that under N.C.G.S. § 62-35 the Commission sets the rules for DEC's North Carolina retail accounting practices. (Tr. vol. 22, 282-283.) Witness Spanos further agreed that Commission Rule R8-27 currently provides for the FERC Uniform System of Accounts to be the default system of accounts for electric utilities that are regulated by this Commission. (Tr. vol. 22, 283.) Finally, witness Spanos testified that the Commission has provided for costs to be recovered from customers after assets have been retired. During cross-examination, witness Spanos was presented with two examples in which Duke Energy Progress' plants were recovered from ratepayers in the years after they were retired. (Tr. vol. 22, 287-292.) The plants in the examples were Asheville, Cape Fear, Lee, Robinson, Weatherspoon, and Morehead City.

Based on the foregoing and the entire record herein, the Commission finds that it is appropriate in this proceeding to adopt the recommendation of the Public Staff. In reaching this conclusion, the Commission gives significant weight to Public Staff witnesses Boswell's and Metz's testimonies. Witness Metz correctly opines that the Company's IRP proceeding is the appropriate venue for a thorough review of early, or any, generation retirements. The Company did not file the requested accelerated depreciation for the plants in either its 2018 IRP or the 2019 Update, which was filed one month prior to the filing of the present rate case.

Witness Boswell stated that the Public Staff has consistently recommended leaving the depreciation rates set at the original retirement date of the plant, and, at the date of actual physical retirement, any remaining net book value be placed in a regulatory asset account and amortized over an appropriate period, to be determined in a future general rate case. This is supported by the examples the Public Staff provided during cross-examination of Company witness Spanos. When presented with Public Staff Doss Spanos Rebuttal Cross-Examination

Exhibit No. 2, witness Spanos affirmed that, Duke Energy requested the same methodology, as proposed by witness Boswell, in Docket No. E-2, Sub 1142. [3]

The Commission has consistently balanced allowing full recovery of early retirement costs to utility companies while not unduly burdening the ratepayers. In the present case, the Company's proposed accelerated depreciation would unduly burden the ratepayers for the next 4.5 to 6.5 years, while allowing DEC recovery of the plants' costs more quickly than last supported by its IRP. The Commission finds the Company's approach to be unbalanced.

Therefore, in light of the foregoing, the Commission finds that the depreciation for the Allen and Cliffside 5 generating plants should be based upon the remaining life as presented in its rate case in Docket No E-7, Sub 1146, and upon actual retirement of each unit, the remaining net book value placed in a regulatory asset account to be amortized over an appropriate period determined in a future rate case.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 3-6

[Depreciation – Other]

The evidence supporting these findings and conclusions is contained in the Application and the accompanying E-1, the testimony of Company witness John Spanos, and the testimony of Public Staff witnesses Roxie McCullar.

[3] See also Public Staff Doss Spanos Rebuttal Cross-Examination Exhibit No. 3, Testimony of Public Staff witness James Hoard.

Depreciation Rates

Company witness Spanos introduced Spanos Exhibit 1, a report entitled "2018 Depreciation Study - Calculated Annual Depreciation Accruals Related to Electric Plant as of December 31, 2018" (Depreciation Study) prepared by Gannett Fleming Valuation and Rate Consultants, LLC. (Tr. vol. 12, 134.) As explained by witness Spanos, the Depreciation Study was to estimate the annual depreciation accruals related to electric plant in service for ratemaking purposes and to determine appropriate average service lives and net salvage percentages for each plant account. The Depreciation Study included dismantlement or decommissioning cost estimates for all steam, hydraulic, and other production plants that are based on decommissioning studies of each generating site performed by Burns and McDonnell, an external engineering firm. (Id. at 145.)

Witness Spanos explained that the life span estimates for DEC's production facilities are based on informed judgment, incorporating factors for each facility such as the technology of the facility, management plans and outlook for the facility, and estimates for similar facilities at other utilities. The life span estimates for nuclear and hydro facilities that have operating licensees were based on the license expiration dates for each facility. (Id. at 140.) The life spans estimates used for depreciation rates for various fossil plants were also updated due to changes in the probable retirement dates, with the life spans at Allen Units 4 and 5, Cliffside Unit 5 and Marshall Units 1 and 2 proposed to be shorted than currently approved. (Id.)

Witness Spanos also described DEC's continued deployment of legacy electric meters with new technology meters, which was planned to be completed by the end of 2019. He indicated that consistent with the Sub 1146 Order, the net book value ($154 million) of the legacy meters will be amortized over 15 years. (Id. at 141.) Finally, witness Spanos testified that the Depreciation Study included depreciation rates for the planned new Clemson Heat and Power Generating facility, as well as for new battery storage assets for generation, transmission, and distribution. (Id. at 149.)

On the issue of depreciation, the Public Staff presented the testimony of Roxie McCullar, a consultant with the firm of William Dunkel and Associates. Witness McCullar testified that based on December 31, 2018 investments, DEC was proposing an increase in its depreciation annual accrual of $108.5 million. (Tr. vol. 16, 595.) Based on Ms. McCullar's investigation, the Public Staff recommended an increase in DEC's depreciation annual accrual of approximately $60.0 million based on December 31, 2018, investments, a decrease of $48.5 million from the amount proposed by the Company. (Id.) The difference between the Company's and the Public Staff's proposed depreciation annual accrual results from retaining the remaining useful life for the Allen and Cliffside 5 generating plants, as discussed in the preceding section, and the four adjustments proposed by witness McCullar, as discussed below.

Contingency

Public Staff witness McCullar recommended that the current approved 10% contingency for future "unknowns" included in DEC's estimate of future terminal net salvage costs continue to be used, as opposed to the 20% proposed by the Company. (Tr. vol. 16, 603.) Witness McCullar noted that in the Sub 1146 Order, the Commission approved the use of a 10% contingency factor, instead of the 20% contingency factor requested by DEC and included in the DEC Decommissioning Cost Estimate Study filed as Doss Exhibit 4 in that docket. She noted that in its Sub 1146 Order, the Commission stated that:

> The Commission is confident that a 10% contingency factor, while less than DEC's requested factor of 20%, should protect the Company from additional costs it will incur but cannot specify at the present date. The Commission also finds that a 10% contingency factor properly reflects the inclusion of items that should push unknown costs downward (i.e. increase in scrap prices, etc.) thereby protecting the ratepayers as well. Based on the foregoing, the Commission concludes that including a contingency factor of 10% should be utilized by the Company. (Id. at 603, quoting from Sub 1146 Order at pp. 172-73).

Witness McCullar noted that DEC's proposed future terminal net salvage costs are again supported by the same DEC Decommissioning Cost Estimate Study reviewed in the Sub 1146 Proceeding.

DEC witness Spanos disagreed with Ms. McCullar's proposal to continue to use the 10% contingency previously approved by the Commission, stating that DEC has learned over the two years since the last Decommissioning Study was performed that the contingency estimates were understated. (Tr. vol. 22, 259.) He did not, however, provide any specific breakdown of costs to support the statement, other than to indicate that it was supported by experience from other industry participants and because more facilities have been decommissioned in recent years. (Id.)

The Commission agrees with DEC that inclusion of a contingency is often a standard industry practice to cover potential unknown costs that may or may not occur. However, the Commission agrees with the Public Staff that DEC has presented no new information or data supporting the need for a contingency percentage greater than the 10% contingency most recently approved by the Commission in the Sub 1146 Order. In that proceeding, the Commission expressed some concern regarding the accuracy of the Decommissioning Study, finding that DEC failed to take into account certain factors and noting that "[w]hile it is impossible to anticipate all future costs, merely being able to identify possible future costs or costs incurred for other projects is not the most firm basis on which to calculate contingency." (Sub 1146 Order at 172.) As a result, the Commission found that a 10% contingency was fair to all parties, and that the Commission was "confident that a 10% contingency factor, while less than DEC's requested factor of 20%, should protect the Company from additional costs it will incur but cannot specify at the present date." (Id. at 172-73.)

The Commission acknowledges witness Spanos's experience and expertise, yet it notes that the contingency percentage utilized in the Depreciation Study and recommended in his testimony is based on the same Decommissioning Study used in the Sub 1146 proceeding. In addition, Mr. Spanos does not provide any new data or information to support his claims regarding recent industry experience supporting an increased contingency percentage. This unsupported position would inappropriately shift a greater portion of the risk of future unknown, unidentified costs on current ratepayers.

The Commission finds that the increased contingency proposed by DEC in this proceeding lacks sufficient basis, and therefore concludes that it is reasonable and appropriate for DEC to continue to use a contingency factor of 10% for net terminal salvage.

Other Production Interim Net Salvage

Public Staff witness McCullar also recommended an adjustment to the interim net salvage percentages of negative five percent proposed by DEC for Other Production Accounts 342, 343, 344, 345, and 346. (Tr. vol. 16, 613.) Witness McCullar pointed out that the historical analyses for these accounts show that, on average, the net salvage has been a positive $6,404,164 per year for the last three years and a positive $7,593,793 per year for the last five years. (Id.) She explained that these positive net salvage amounts indicated that DEC's booked gross salvage exceeded the Company's incurred costs of removal and thus, DEC did not need to collect interim removal costs for these accounts. (Id.) Therefore, witness McCullar proposed the continued use of a 0% interim net salvage, consistent with the Commission's finding in the Sub 1146 proceeding, and based on DEC's actual experience since that time. (Id.) She noted that the 0% interim net salvage would not include the final decommissioning costs. (Id.)

DEC witness Spanos testified that he recommended an interim net salvage percent of negative six percent for Other Production accounts, with the exception of rotable parts at combined cycle plants. (Tr. vol. 22, 193.) He recognized that the Commission adopted an estimate of zero percent for these accounts in the Sub 1146 Proceeding, but stated that data over the past two years supports a negative net salvage estimate for each of these accounts. (Id.) Witness Spanos contended that the higher gross salvage numbers in DEC's previous depreciation study were related to the rotable parts of combined cycle facilities that are regularly refurbished and typically experience positive net salvage. (Id. at 195.) He noted that since the previous study, DEC has begun to account for rotable parts in a separate sub-account, resulting in the non-rotable parts accounts experiencing negative net salvage. (Id. at 196.)

The Commission finds that the Public Staff's proposal to set an interim net salvage percentage of zero for Accounts 342, 343, 344, 345, and 346 is reasonable. While the past two years do indicate that some non-rotable parts accounts have established negative net salvage, historical data continues to show that the Company's positive net salvage amounts indicate that DEC does not need to collect interim removal costs for these accounts. To the extent this trend continues in future years, this issue can be reexamined in the next base rate case.

AMI Meter Average Service Life

The Public Staff's third recommended change to the Company's depreciation rates was to adjust DEC's proposed 15-year average service life of its Advanced Metering Infrastructure (AMI) meters to 17 years. Witness McCullar recommended that a life of 17 years be used, especially in light of DEC's limited experience with AMI meters. (Tr. vol. 16, 615.)

DEC witness Spanos testified on rebuttal that the Commission accepted a 15-year average service life for AMI meters in the Sub 1146 proceeding, and that none of the factors affecting the life of the assets have changed since that time.

(Tr. vol. 22, 178.) He recommended to continue to use the 15-S2.5 survivor curve, which he stated is consistent with the manufacturer's recommendation for the physical life of AMI meters, but also considers that meters are retired for other reasons, such as damage or obsolescence. (Id.) He noted that in response to discovery, DEC had stated that the meter manufacturers had estimated a life of 15 to 20 years for the meters, and that witness McCullar's recommendation was in the middle of that range. (Id.)

On cross-examination, witness Spanos testified that under the 15-S2.5 survivor curve, half of the assets are estimated to be retired prior to the average life, and an equal number would be retired after the average term is reached. (Tr. vol. 12, 170.) Looking at the life tables and age intervals for Account 370.02 (Meters – Utility of the Future) however, Mr. Spanos testified that for the first eight and a half years of AMI deployments, DEC has not recorded any AMI meter retirements. (Id. at 172.) Witness Spanos noted that the utility has therefore had little opportunity to utilize statistical analysis to determine its estimate, and informed judgment is therefore required for the class. (Id. at 174.)

The Commission finds that it is reasonable to use an average service life of 17 years for the new AMI meters, which is even below the middle of the manufacturers' range. While DEC has pointed out certain technological characteristics of AMI meters, it has not shown that the manufacturers' estimates were high, inaccurate, or unreliable. DEC did not present any data supporting the retirement of meters that would be expected of the 15-S2.5 survivor curve on which it based its depreciation rates. As such, the Public Staff's proposal to rely on the manufacturer's estimate is reasonable. At the time DEC begins to experience retirements supporting the use of the S15-2.5 survivor curve, or identifies an alternative survivor curve that may better fit the retirements experienced for this property unit, this issue can be reexamined in future base rate case proceedings.

Mass Property Future Net Salvage

The Depreciation Study included as Spanos Exhibit 1 provided support for determining net salvage estimates for each plant account. Witness Spanos testified that the net salvage percentages estimated in the depreciation study were based on informed judgment that incorporated factors such as the statistical analyses of historical net salvage data" for the period 2003 to 2018; information provided by the Company's operating personnel, general knowledge and experience of industry practices; and general industry trends. (Tr. vol. 12, 143.) He further testified that the statistical net salvage analysis included an analysis of trends based on three-year moving averages and the most recent five-year indications. (Id.)

Public Staff witness McCullar testified that in addition to relying on historic net salvage ratios, which are influenced by historic inflation levels, she also reviewed future net salvage costs included in DEC's proposed depreciation accrual and the actual net salvage costs incurred by DEC on average over the recent five-year period. (Tr. vol. 16, 622.) Witness McCullar noted cases in several jurisdictions that have adopted future net salvage percentages that recognized the inflated dollars included in the historic net salvage ratio and adopted future percentages that recognized the time value of cost of removal due to inflation. (Id.

at 619-21.) Table 3 included in Ms. McCullar's testimony provided a comparison of the actual net salvage costs incurred by DEC on average over the recent five-year period to future net salvage costs included in DEC's and the Public Staff's proposed depreciation accruals. Witness McCullar testified that her analysis provides a "reasonableness check" of the proposed future net salvage percents, and that her "proposed future net salvage accrual amounts consider DEC's historic practices, the impact of inflation, and builds a reserve for reasonable estimated future net removal costs associated with future retirements, based on the type of investments in the account, and my previous experience." (Id. at 624.) As a result of her analysis, for Account 366, Underground Conduit, Ms. McCullar recommended a future net salvage percent of -10%, which differs from DEC's proposed -15%. (Id. at 615.) Witness McCullar noted that even under her recommendation, the annual accrual for Account 366, Underground Conduit net salvage would still be $231,716, which is about 14.3 times the average annual amount DEC actually incurred. She further testified that her recommendation provides recovery of the expected cost of removal in the near future and builds the reserve for the future cost of removal associated with future retirements. (Id. at 625-25.)

DEC witness Spanos in rebuttal stated that the existence of a small number of instances where different approaches were used does not indicate that DEC's approach is consistent with the method used in the vast majority of jurisdictions. (Tr. vol. 22, 184.) He also testified that he did not believe that Ms. McCullar's analysis provides a reasonable basis to estimate future net salvage, because it is based on the premise that depreciation accruals for net salvage should be similar to, if not the same as, the net salvage occurred each year. (Id. at 191.) He stated that the goal of depreciation is to recover capital costs, including net salvage over the service life of the assets, and that there is not necessarily alignment between depreciation accruals for net salvage and incurred net salvage. Lastly, he notes that expressing historical net salvage as a percentage of historical retirements as he proposes properly recognizes the relationship between net salvage and retirements. (Id. at 191-92.)

On cross-examination, Mr. Spanos testified that because the net salvage percent you determine should reflect what you expect to happen going forward, you can't just focus on historical analysis. (Id. at 262.) He noted that with regard to Account 366, however, based on informed judgment, that relying on historic salvage over a longer period of time is more representative than the most recent five-year period of time. (Id. at 264.) Witness Spanos acknowledged that the Kansas State Corporation Commission (KSCC) in a recent decision found that a net salvage analysis that estimates appropriate levels of future net salvage, and does not rely solely on historic expense levels is appropriate. (Id. at 265-67, *citing Order on Atmos Energy Corporation's Application for a Rate Increase* at paragraphs 52-54; KSCC Docket No. 19-ATMG-525-RTS (February 24, 2020).) He also acknowledged that the KSCC found that the approach recommended by the Commission Staff in that proceeding, which in part considered the level of net salvage in recent years, not as a percentage of retirements, best balanced the interests of the utility's current and future ratepayers. (Id.)

The Commission finds that the Public Staff's proposal of a future net salvage percent of -10% for Account 366, Underground Conduit is reasonable, since it is within the range of the historic net salvage percents (Spanos Exhibit 1 at 342) and builds a reserve for future removal costs (Tr. vol 16, 623-24), while balancing the interests of current versus future ratepayers.

Conclusions on Depreciation

Based on the foregoing conclusions regarding the continued use of the current approved final retirement year for Cliffside Unit 5 and Allen for depreciation purposes, the use of a 10% contingency for future "unknowns" in the estimate of future terminal net salvage costs, use of an interim net salvage percentage of zero for Accounts 342, 343, 344, 345, and 346, use of an average service life of 17 years for new AMI meters being deployed, and the use of the net salvage analysis proposed by the Public Staff, the Commission finds it is reasonable and appropriate to approve the use of the Public Staff's proposed depreciation rates as shown on witness McCullar's Exhibit RMM-1.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7-10

[GIP Cost Allocation Study]

The evidence supporting these findings of fact is found in the testimony of Public Staff witnesses Jeff Thomas and James McLawhorn, and DEC witness Janice Hager.

In his testimony, Public Staff witness Thomas raised concerns about the Company's allocation of GIP reliability benefits and equity in cost allocation and rate design. He was able to determine from the Company's own CBAs that claimed customer reliability benefits for C&I customers are estimated at approximately $6 billion, representing over 97% of customer reliability benefits broken out by class, 73% of total customer reliability benefits, and 64% of all GIP program benefits. (Tr. vol. 17, 414-15.) In contrast, residential reliability benefits only comprise 1.8% of all GIP program benefits. (Id. at 415.) He explained that while it can be assumed that all customers benefit equally from the other benefit categories (particularly operational benefits), customer reliability benefits comprise the vast majority of all claimed benefits and their allocation has an enormous impact on the allocation of total GIP benefits. (Id.)

Witness Thomas explained that if there is no new allocation factor proposed for GIP investments, all GIP costs are expected to be allocated among customer classes according to the allocation factors that have historically been used for T&D expenditures. (Id.) Distribution investments are typically allocated using a non-coincident peak allocation factor; for residential customers, the jurisdictional factor is approximately 45% and the class factor is approximately 61%.[4] Transmission investments are allocated on a transmission demand allocation factor; for residential customers, the jurisdictional factor is approximately 24% and the class factor is approximately 46%.[5] (Id. at 416-17.)

[4] This number reflects the primary distribution allocation factor found in DEC's Cost of Service Study (See E-1 Item 45a).

[5] This number reflects the transmission demand allocation factor found in DEC's Cost of Service Study (See E-1 Item 45a). Public Staff witness McLawhorn has proposed utilizing a

Witness Thomas testified that he is not recommending that GIP costs be allocated differently than traditional T&D investments at this time. However, he believes the issue is ripe for Commission consideration, particularly in light of the Commission's *Order Approving Revised Interconnection Standard and Requiring Reports and Testimony* in Docket No. E-100 Sub 101, which requires the Company to "file testimony in [its] next general rate case application[] regarding the benefits that distributed generators are receiving from the Utility's System, estimating their share of related costs, and providing options for recovering those costs from distributed generators." He concluded that if the Commission agrees that this issue merits further study, DEC's and DEP's planned study of the impact of distributed generation could be expanded to require an evaluation of possible alternative methods of allocating GIP investments that provide primarily reliability benefits. (Id. at 417.)

In his direct testimony, Public Staff witness McLawhorn noted witness Thomas's testimony on the allocation of GIP investments and recommended that the Commission order DEC to study the allocation of GIP investments based on the realized benefits of those investments, and report its findings no later than the filing of its next general rate case. (Tr. vol. 18, 246-47.)

In her rebuttal, Company witness Hager proposed allowing the investments associated with GIP to follow the same cost causation principles that are applied to the investments in the same FERC accounts as reflected in the COS study. In

different cost allocation methodology (SWPA); the corresponding residential jurisdictional transmission allocation factor is 26.7%; the residential retail transmission allocation factor is 50.5%.

her opinion, attempting to allocate any investment costs for ratemaking purposes based on perceived benefits realized by customers, as differentiated from cost causation to the utility, is likely to be very subjective and thus controversial. During the hearing, she characterized the undertaking of the GIP study advocated by witness McLawhorn as a "waste of time" and that it would not be useful for purposes of cost of service because it would depart of principles of cost causation. (Tr. vol. 12, 222-23, 299-300.)

In January of 2020, the Regulatory Assistance Project (RAP) published *Electric Cost Allocation for a New Era* (RAP Manual), identified during the hearing as Public Staff Pirro Hager Cross-Examination Exhibit 1. (Tr. vol. 13 Exhibits.) According to its authors, this cost allocation manual is intended to build upon previous manuals on cost allocation, including the 1992 NARUC *Electric Utility Cost Allocation Manual* cited by witness Hager in her testimony. (RAP Manual 15-16.) The RAP Manual illustrates the changes in the electric system that have occurred since the 1990's. The traditional electric system consisted of central general, transmission, and distribution. (Id. at 32, Figure 7.) The modern electric system includes distributed generation, storage, smart appliances, demand side management, and microgrids. (Id. at 33, Figure 8.) With Advanced Metering Infrastructure (AMI) technology, a utility can obtain both more data and more granular data than with older meters, and can perform functions other than measure electric use, such as demand management. (Id. at 18.) The authors of the RAP manual suggest that two primary conceptual principles guide the way for an equitable division of costs among customers: 1) cost causation and 2) costs follow the benefits, and that costs follow benefits is the superior principle in cost allocation. (Id.)

The Commission finds that the electric system has changed in the years since the publication of the NARUC CAM manual in 1992. As the RAP manual indicates, the electric system performs many more functions than just transmitting electricity from a generation source to a customer. Similarly, GIP investments are designed to "transform" the grid, providing benefits that may or may not line up with traditional cost allocation principles. The Commission agrees with the Public Staff that given that the cost burden of GIP may be disproportionate to the benefits received by customers, further study is needed. Therefore, the Commission finds and concludes that the Company, in consultation with the Public Staff and other interested stakeholders, shall study the allocation of GIP investments based on the realized benefits of those investments, and report its findings no later than the filing of its next general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11-18

[CIGFUR Stipulation and EDIT Return]

The evidence supporting these findings and conclusions is contained in the Application and the accompanying E-1, the entire record of Docket No. E-7, Sub 1214, the testimony of Company witnesses Michael Pirro and Janice Hager, CIGFUR witness Nicholas Phillips, and Public Staff witnesses James McLawhorn and Jack Floyd.

On May 29, 2020, the Company and CIGFUR filed an Agreement and Stipulation of Settlement (CIGFUR Stipulation). No testimony supporting the settlement was filed. The Stipulation provided in Section II. for an ROE of 9.75% and a capital structure of 52% equity and 48% debt. It also supported the Company's request for a deferral of Grid Improvement Plan (GIP) costs over three years. On August 6, 2020, the CIGFUR Stipulation was amended to provide that should the Commission approve an ROE of 9.6%, this section of the Stipulation should be deemed to be fulfilled. The Commission has made findings addressing ROE, capital structure, and the GIP deferral i*nfra* that address these terms of the CIGFUR Stipulation.

Section III.B of the CIGFUR Stipulation provides that in the next rate case, DEC will propose to allocate the deferred GIP costs among classes, consistent with its distribution cost allocation methodologies proposed in this Docket, including use of the MSM and voltage differentiated allocation factors for distribution plant. Additionally, with Commission approval, the Company will use this methodology to allocate GIP costs during the three years for which it may seek recovery in future rate cases. Under cross examination, DEC witness Hager did not disagree with Public Staff counsel's statement that 64% of GIP costs were charged to residential and small general service customers and 10% to OPT-V and large commercial and industrial customers. (Tr. vol. 12, 303.) At the hearing, CIGFUR witness Phillips indicated that this provision would allow the Commission to approve the cost allocation method it has approved for DEC in the past. (Id. at 148.) He also agreed with counsel for the NCJC et al. that the Commission had not considered whether the use of the MSM was appropriate for GIP. (Id. at 150-51.) Mr. Phillips also contended that the CIGFUR Stipulation contained no provisions that would tie the Commission's hands or limit future investigations. (Id. at 143.)

The Commission finds that it is inappropriate to determine the allocation of deferred GIP costs at this time. The Commission has already accepted the provision in in the Second Partial Stipulation requiring a COS Study, as well as determining the MSM to be appropriate for use for this proceeding. The Commission does not accept this term of the CIGFUR Stipulation because it ties DEC's hands based on a set of facts that may not be appropriate in a future rate case. Each rate case must rely upon its own set of facts and applications of law. Thus, the Commission will only consider future costs, GIP or otherwise, in the context of that future case, as well as the allocation of those costs to the customer classes. As it stands today, the Commission has approved the recovery of some GIP costs in this proceeding which are to be allocated using the appropriate, distribution, transmission, and other allocation factors as determined using the MSM. Future GIP costs could require a different allocation process and factors. The Commission expects DEC to use the results of the COS Study in future rate cases. To bind itself to use only a particular method at this point is inappropriate. Thus, the Commission finds that it is premature and inappropriate for DEC to agree in advance of a future COS Study to a particular method to allocate deferred GIP costs among the customer classes. The Commission will make that determination in the next general rate case. Therefore, the Commission holds that this provision of the CIGFUR Stipulation is neither just, reasonable, nor in the public interest.

Under Section IV., the parties agreed to refund unprotected Excess Deferred Income Taxes (EDIT) on a uniform cent/kWh basis. In his direct and supplemental testimony, DEC witness Pirro described how he designed the Year 1 rate for the EDIT Rider by taking the rider revenue requirement, aggregating it to the four different rate classes based on how it was allocated in the Company's 2018 per books COSS, and dividing each class by the applicable test year retail billed sales. (Tr. vol. 12, 253.259.) Mr. Pirro noted that these class-specific EDIT credit rates were in line with the cost allocation method used. (Tr. vol. 13, 27.) Witness Pirro testified that he used the revenue requirement from McManeus Exhibit 4 to develop the rates in Pirro Exhibit 9. (Id.) In his second supplemental testimony, witness Pirro explained that he had revised the EDIT Rider pursuant to the CIGFUR Settlement to refund EDIT on a uniform cents per kWh basis. (Tr. vol. 12, 278.) Under this method, one factor would be used for all customers, with the OPT-V class receiving a larger EDIT credit than it paid in EDIT, according to Mr. Pirro. (Tr. vol. 13, 28.) Mr. Pirro attempted to justify this overpayment of EDIT to one class that was paid in by another as a way to correct subsidization within base rates, but he admitted that base rates and EDIT should be considered separately. (Id. at 28-29.) CIGFUR witness Phillips also agreed that paying EDIT on the uniform cents per kWh basis would reduce any subsidies among classes and stated his belief that it was also done in this manner in the last DEP case. (Tr. vol. 22, 146.) Public Staff witness Floyd advocated for using Mr. Pirro's original methodology that returned the EDIT to classes based on how much each class had paid. He said that his proposed method was fairer as industrial customers would receive more than they had paid if the CIGFUR Settlement method were used. (Tr. vol. 18, 334.)

The Commission declines to adopt this provision of the CIGFUR Settlement as it is unreasonable and not in the public interest in this case. EDIT results from the overpayment of taxes by customers associated with the revenues those customers have paid. In other words, those overpayments are determinable from the Company's books and records of customer billing revenues. While different customer classes may have different rates of return (ROR), the Commission acknowledges that these RORs are highly dependent on the cost of service methodology utilized, as well as the time period during which the cost of service study was calculated. As such, subsidy/excess issues should be resolved on the basis of equity between customer classes and their relationship to the overall ROR resulting from this particular proceeding.

While in prior rate cases for DEC and DEP, use of a uniform EDIT rate was agreed to as part of a settlement, no party contested this issue in those cases, and the Commission accepted the settlement terms on EDIT without making detailed findings of fact as to the appropriateness of a uniform rate. However, we note that in our recent *Order Accepting Public Staff Stipulation in Part, Accepting CIGFUR Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase*, Docket No. E-22, Sub 562, (February 24, 2020) (DENC 562 Order) of which we took judicial notice, the Commission approved the provision of the Stipulation between Dominion Energy North Carolina and the Public Staff that the EDIT Rider credit should be allocated to customer classes based upon North Carolina basic (non-fuel) rate revenue annualized based upon current rates for 2018. *See* DENC Order at 60-63.

With this issue now squarely before the Commission, the Commission finds it inappropriate to address any subsidy issues through reassignment of EDIT. The Commission agrees with Mr. Floyd that returning EDIT credits by customer class is a more equitable method by which to return customers' overpaid EDIT. Thus, the Commission further holds that in this case it is inappropriate to refund unprotected EDIT and deferred revenue giveback overpaid by customers through the EDIT rider on a uniform cent/kWh basis, and rather should be refunded as a levelized EDIT credit by specific customer-class divided by the adjusted class test year sales.

Under Section V., DEC and CIGFUR agreed to five conditions related to cost of service and rate design. The first condition would obligate DEC to discuss potential cost of service methodologies that the Company may recommend and file and to consider the results of a cost of service study based on the Summer/Winter Coincident Peak method. The second condition would require DEC in its next rate case, to adjust peak demand to remove curtailable/non-firm load, even when the load reduction is not requested. The third condition would require DEC in its next two fuel proceedings to propose the uniform percentage average bill adjustment methodology. The fourth condition would require DEC to allocate distribution expenses using the MSM in the next three rate cases unless the Commission rejects the method. Finally, the Company also agreed to explore certain rate designs and file the rates if there was interest from CIGFUR customers.

In his second supplemental testimony, Public Staff witness Floyd addressed his opposition to the provision regarding the adjustment to remove curtailable non-firm load, noting that he had agreed in his testimony in Docket No. E-22, Sub 479, to impute the winter peak component as if Dominion had activated all of its available demand-side management (DSM) programs at the time of the winter peak. (Tr. vol. 18, 336.) He explained that his opposition to the provision in this case was not inconsistent with his position in the Dominion case because Dominion used a COS methodology that equally weighted summer and winter peaks, it activated all DSM and interruptible loads at the time of summer peak, but only a portion at winter peak. He explained that without the adjustment, the relationship between the two peaks would have been distorted. (Id. at 337.)

He also pointed out that, unlike DEC, Dominion used a COS methodology that used an average demand component, thus preventing the interrupted load from avoiding the responsibility of any production plant-related costs, as would occur with a single peak allocator used in this case. Also, DEC had not activated any of its DSM at the time of summer peak in the test year. Thus if the adjustment had been made for the test year, customers whose interruptible load was removed whether they were interrupted or not would have avoided paying production plant-related costs that should have been assigned to them. (Id.) Mr. McLawhorn pointed out on cross examination that even if DEC did interrupt load in a future test year, the Public Staff would still oppose such an adjustment as long as DEC continued to rely on a COS methodology that did not include an average component because certain customers would be able to avoid paying for production and possibly transmission plant that they used the vast majority of hours. (Tr. vol. 19, 53-54, 81-82.) Mr. McLawhorn and Mr. Floyd agreed that the Public Staff's ultimate position would depend on the COS methodology used by the Company and whether it used interruptible and DSM resources. (Id. at 82.)

DEC witness Hager indicated that if residential curtailable load is lower than industrial curtailable load, this provision would result in more costs being allocated away from commercial and industrial customers. (Tr. vol. 12, 306.) CIGFUR witness Phillips stated that when Duke has curtailable load, it does not need to build or buy capacity to serve that load and thus that load should be removed from the demand allocator. (Tr. vol. 22, 140.)

The Commission notes that no party opposed the agreement between DEC and CIGFUR to meet to discuss potential cost of service methodologies that the Company may recommend and the agreement for DEC to file and consider the results of a cost of service study based on the Summer/Winter Coincident Peak method. The Commission finds it reasonable and in the public interest for the Company to consider appropriate COS allocation methodologies and thus approves this provision of the CIGFUR Stipulation.

With respect to adjusting peak demands in cost of service to recognize interruptible load, the Commission gives substantial weight to the testimonies of Public Staff witnesses McLawhorn and Floyd. As described by witness Floyd, the adjustment in the Dominion case was made to recognize the benefits of all demand response resources at the time when Dominion called a portion of those resources. Witnesses Floyd and McLawhorn further explained how a COS methodology based solely on a single coincident peak could impact an adjustment to reflect interruptible loads by distorting the peak demands that would be used to allocate peak demand-related costs (e.g., production and transmission).

The Commission finds it is appropriate for the Company to adjust all peak demand hours incorporated into the peak demand inputs used in various COS methodologies to reflect all available demand response resources (interruptible load and other DSM programs). However, this is limited to the extent that the Company actually realizes a level of demand reduction for the specific hours under consideration. If an adjustment is made, the Company shall impute the total amount of available resource for all customer classes as appropriate as if the entire portfolio of DSM and interruptible resources were called.

Another provision in this section of the Stipulation requires DEC in its next two fuel proceedings to propose the uniform percentage average bill adjustment methodology and to allocate distribution expenses using the MSM in the next three rate cases unless the Commission rejects the method. No evidence regarding the use of the uniform percentage average bill adjustment methodology was presented. Use of the MSM is discussed *infra* in the discussion of COS. The Commission rejects both of these provisions as they are not reasonable and in the public interest; again, they tie DEC's hands when it is studying issues that may call for new approaches. Therefore, the Commission declines to require the Company to propose the uniform percentage average bill adjustment methodology in its 2021 and 2022 annual fuel cost proceedings. The Company may do so if it determines that the methodology is appropriate. The Commission also declines to approve the provision of the CIGFUR Stipulation requiring DEC to propose the MSM for determining classification of distribution costs for specific rate schedules in this proceeding. Instead, the appropriateness of the MSM shall be considered in the comprehensive rate study. Finally, this section of the CIGFUR Stipulation also requires the Company to explore certain rate designs and file the rates if there is interest from CIGFUR customers. The Commission has no qualms with this provision and finds it to be reasonable and in the public interest.

Therefore, based upon all of the evidence in the record, the Commission accepts, in part, the CIGFUR Stipulation as discussed herein. In addition, the CIGFUR Stipulation as modified, is entitled to substantial weight and consideration in the Commission's decision in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 19-21

[Commercial Group / Harris Teeter Stipulations]

The evidence supporting these findings and conclusions is contained in the Application and the accompanying E-1, the entire record of Docket No. E-7, Sub 1214, the testimony of Company witness Michael Pirro, Harris Teeter witness Bieber, and Public Staff witness Jack Floyd.

On June 1, 2020, the Company and the Commercial Group filed an Agreement and Stipulation of Settlement (CG Stipulation) and on June 2, 2020, the Company and Harris Teeter filed an Agreement and Stipulation of Settlement (HT Stipulation). These settlements are substantially similar. No testimony supporting either settlement was filed. Both Stipulations provided for an ROE of 9.75% a capital structure of 52% equity and 48% debt. They also contained provisions wherein Harris Teeter and the Commercial Group agreed not to oppose the Company's request for a deferral of GIP costs over three years. On August 6, 2020, both Stipulations were amended to state that should the Commission approve an ROE of 9.6% applied to a capital structure of 52% equity, 48% debt, Paragraph 4 of each Stipulation should be deemed to be fulfilled. The Commission has made findings addressing ROE, capital structure, and the GIP deferral i*nfra*. that address these terms of the CG/HT Stipulations.

Both Stipulations include a provision agreeing that any GIP costs allocated to OPT-V customers will be recovered through OPT-V demand charges. They also provide that the OPT-VSS off-peak energy charge shall be set at 3.0222 cents/kwh and the on-peak energy charge shall be increased by a percentage amount that is equal to half of the overall percentage increase for the OPT-VSS rate schedule. Further, the agreements provide that the demand charges for the OPT-VSS rate schedule shall be adjusted by the amount necessary to recover the final OPT-VSS revenue target.

HT witness Bieber contended that the proposed rate design for "the OPT-VSS rate schedule under-recovers the demand-related charges while over-recovering the energy-related charges relative to the underlying costs. (Tr. vol. 16 Errata, 7.) He advocated allocating only demand costs to the demand charge. (Id. at 11.) In his rebuttal testimony, Company witness Pirro rebutted this proposal stating,

> The rate designer's task is to design a rate that best mimics the cost of serving customers across a range of usage without all cost elements being strictly defined by the rate structure. An industry method used to accomplish this is to allocate a portion of demand costs to be included in the energy charge. The simplistic notion that all demand costs be included in a demand charge and all energy costs be included in an energy charge would essentially invalidate most of the rate structures in the industry across the country. Also, if rates increase, more and more costs would be unjustifiably borne by the lower load factor customers in the group. . . .

(Tr. vol. 12, 268.)

Public Staff witness Floyd echoed this sentiment when he stated that the Public Staff has not advocated for the recovery of a particular type of cost through a particular rate element, i.e., a demand rate to recover demand costs. (Tr. vol. 19, 71.) Mr. Floyd stated that GIP costs had elements of demand and customer-related classifications and that there was debate as to whether they also had energy elements as well. (Id. at 72.) On cross examination, Mr. Pirro stated that customers in the OPT-VSS class could lower their peak demand, but noted that the customers within the Secondary Small class are generally similar high load factor customers. (Tr. vol. 13, 20.)

The Commission finds that assigning specific costs to be recovered through specific rate elements places constraints on the rate designer and the Company that could distort and frustrate the overall objectives of cost recovery. While there may be some unique circumstances that would justify such specificity, they would need to be carefully studied to ensure that they do not produce a significant cost shift among all customers. No such evidence of this type of study has been introduced in this case. As such, the Commission finds that it is inappropriate to require the Company to recover its GIP-related costs solely through demand rates in OPT-V or any other rate schedule that includes a demand rate. Therefore, the Commission holds that this provision of the CG and HT Stipulations is unreasonable and not in the public interest.

In regard to the on- and off-peak energy rates agreed to in the CG and HT Stipulations, HT witness Bieber indicated that DEC's proposed rate for the OPT secondary under-recovers the demand-related charges while over-recovering the energy-related charges relative to the underlying cost. DEC witness Pirro explained that the revenues assigned to the VSS class would not be shifted to any other class under the terms of the settlements. (Tr. vol. 13, 22.) He explained that the agreed upon rates were more in the spirit of the original intent of the OPT-V rates, which was to provide attractive off-peak pricing for customers to make business decisions in their operations. (Id. at 23, 25.) In his second supplemental testimony, Public Staff witness Floyd decried the impact that the CG and HT Stipulations could have on the proposed rate design study by constraining the freedom to design particular rate elements. (Tr. vol. 18, 338-41.) He indicated that he did not have an issue with the $0.0322 off-peak rate *per se*, but recommended that the Commission take a cautious approach due to the impact on the OPT class and other classes. (Tr. vol. 19, 65.)

The Commission finds that for purposes of setting rates in this proceeding, the terms related to the on- and off-peak energy rates that would apply to OPT-VSS in the CG and HT Stipulations are reasonable and in the public interest. However, the Commission’s finding here should not be interpreted as binding or constraining in any way on the comprehensive rate study and any adjustment or change to that rate that may be recommended by the rate study.

Therefore, based upon all of the evidence in the record, the Commission accepts the CG/HT Stipulations as modified herein, and finds that those provisions are just and reasonable as noted herein, and serve the public interest. In addition, the CG/HT Stipulations, as modified, are entitled to substantial weight and consideration in the Commission's decision in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 22-28

[Credit Metrics]

Summary of the Testimony

DEC witness Karl Newlin testified in his direct testimony that he is Senior Vice President, Corporate Development and Treasurer for Duke Energy. He testified that under his supervision, the Treasury Department arranges and executes all capital raising and liquidity transactions, including credit facilities and commercial paper, debt securities, preferred and hybrid securities, and common stock, as well as daily cash management for Duke Energy and its subsidiaries. His responsibilities include managing Duke Energy and its subsidiaries' credit ratings and interactions with the major credit rating agencies, commercial banks, and the capital markets. (Tr. vol. 11, 376-77.)

Mr. Newlin testified that DEC faces substantial capital needs over the next several years. DEC competes for capital in the open market and must appeal to debt and Duke Energy's equity investors to attract the capital it needs. (Id. at 378.) He stated that DEC, at all times, seeks to maintain its financial strength and flexibility, including its strong investment-grade credit ratings, ensuring reliable access to capital on reasonable terms. He testified that specific objectives that support financial strength and flexibility include: (a) maintaining at least 53 percent common equity for DEC on a financial capitalization basis; (b) ensuring timely recovery of prudently incurred costs; (c) maintaining sufficient cash flows to meet obligations; and (d) maintaining a sufficient return on equity to fairly compensate shareholders for their invested capital. (Id. at 379.)

Mr. Newlin testified that as of the date he filed his direct testimony, on September 30, 2019, DEC's outstanding debt was rated as follows:

Rating Agency	**S&P**	**Moody's**
Issuer / Corporate Credit Rating	A-	A1
Senior Secured	A	Aa2
Outlook	Negative	Stable

He testified that obligations carrying a credit rating in the "A" category are considered strong investment-grade securities subject to low credit risk for the investor. (Id. at 383.)

DEC witness Newlin testified that S&P utilizes a family rating methodology, whereby the credit rating and outlook of the parent company, Duke Energy, is applied to each of the parent's subsidiaries. He testified that S&P revised its outlook to "Negative" on May 20, 2019, citing concerns of weaker financial measures due to 2018 storms, uncertainty over growing coal ash remediation costs and recovery in the Carolinas, regulatory lag during a period of robust capital spending, and delays related to the Atlantic Coast Pipeline. He testified that S&P stated in its May 2019 Duke Energy report that the outlook could be restored to stable if Duke Energy and its subsidiaries improve financial measures in the next 12-24 months without any deterioration in the Company's business risk profile. (Id. at 384-85.)

DEC witness Newlin further testified that the Federal Tax Cuts and Job Act (TCJA) in December 2017 resulted in electric utilities, including DEC, and their holding companies losing some of the cash flow contributions from deferred taxes on an ongoing basis. (Id. at 387.) He testified that this loss of cash flow would reduce DEC's funds from operations to debt percentage (FFO/Debt). (Id. at 388.) He testified that DEC's Excess Deferred Income Taxes (EDIT) are customer supplied funds. He testified that DEC proposed to flow the property-related unprotected EDIT back to customers over a 20-year period, which would smooth out the cash flow hit DEC must take as it returns the EDIT to customers. (Id. at 392.)

On rebuttal, Mr. Newlin testified that he disagreed with Public Staff witness Hinton's recommendation to flow back unprotected EDIT over a five-year period, as the result on cash flows would be credit weakening for DEC. He testified that the five-year unprotected EDIT flowback would reduce DEC's FFO/Debt ratio, and Moody's downgrade threshold is a FFO/Debt ratio of 25%. (Id. at 417, 421.)

Mr. Newlin disagreed with Mr. Hinton's recommendation that DEC should moderate upstream equity dividends to Duke Energy to alleviate potential credit pressures as a result of accelerated EDIT flowback. Mr. Newlin also disagreed with Mr. Hinton's testimony that Duke Energy can use funds from its $2.5 billion November 2019 common equity issuance to further decrease infusions to the parent. He testified that the equity infusion was intended to protect Duke Energy's credit in light of a range of scenarios related to the delay and regulatory uncertainty around the Atlantic Coast Pipeline. (Id. at 422-23.) He testified that DEC's senior unsecured credit ratings of A1 and A- from Moody's and S&P respectively, would likely be downgraded if the utility were to lose the full debt and equity return on coal ash remediation costs. He testified this FFO/Debt metric is the primary financial measure used by the rating agencies to determine the credit quality of utility companies, including DEC. (Id. at 426.)

Upon cross examination, DEC witness Newlin agreed that Public Staff Newlin Rebuttal Cross-Examination Exhibit 1 states DEC's dividends paid to parent Duke Energy for the years 2015 through 2019. When excluding the outlier 2016, which was the year of the Piedmont Natural Gas merger with Duke Energy, the four-year average annual dividends paid were $513 million. He testified that DEC Form E-1, Item 33 d, Line 17, filed September 30, 2019, listed the dividends to be paid 2020 through 2023, which annually average $1.013 billion, an increase of 97% compared to 2015 through 2019, excluding the outlier 2016. (Tr. vol. 1, 72-73.)

Mr. Newlin testified that the DEC response to Public Staff Data Request No. 230 Items 6 and 7 are shown on Public Staff Newlin Rebuttal Cross-Examination Exhibit 4. In his direct testimony, Mr. Newlin stated that a DEC downgrade from Moody's Secured Aa2 rating to Aa3 based on current historically low interest rates and near record tight credit spreads would cost DEC secured debt issuance 5 basis points. This Exhibit 4 showed DEC issued $900 million long term debt in

January 2020, with a weighted debt cost rate of $2.78%, and the 5 basis point increase would have increased the weighted debt cost rate to 2.83%. He testified that DEC Public Staff Data Request No. 230, Items 6 and 7 states that the DEC planned long term debt issuances and long term debt maturities for the four years, 2020 through 2023. This cross examination exhibit showed that the DEC estimated impact on cost of debt based upon a 5 basis point debt cost increase, considering long term maturities and long term issuances, would be 0.00% in 2021, 0.01% in 2022, and 0.01% in 2022. (Id. at 93-98.)

Mr. Newlin testified that the Public Staff and DEC grid deferral stipulation, if approved by the Commission, would be both quantitative and qualitative credit supporting with respect to the credit rating agencies. (Id. at 66-67.)

DEC witness Newlin further testified that DEP, with its lower Aa3 Senior Secured Credit Rating, issued $700 million in 30-year first mortgage bonds on August 20, 2020 at 2.50%. (Id. at 76.) Mr. Newlin testified that Duke Energy issued $2.5 billion in new stock with a forward settlement whereby the funds are to be received by December 2020. (Id. at 79.)

He testified that Moody's looks at FFO to debt on a sustained basis, and Moody's does not define sustained basis. He testified that Moody's uses a FFO to debt three-year basis in its reporting, similar to what Public Staff witness Hinton did in his testimony. (Id. at 81.)

On cross examination, Mr. Newlin testified the credit rating agencies consider riders as credit positive. He agreed that DEC has the following riders: annual fuel adjustment rider, annual renewable energy adjustment rider, annual demand side management and energy efficiency rider, and annual competitive procurement of renewable energy rider. (Id. at 83-84.)

Mr. Newlin further testified that Moody's October 31, 2019 credit opinion for DEC cited the strengths of the credit support of DEC's regulatory environment. He testified Moody's cited as credit supportive DEC's growing customer service base, the composition of DEC's customers, and the fact that DEC is part of the strength of the Duke Energy utility system. (Id. at 85.)

Mr. Newlin testified that the Moody's quantitative rating comprises 50 percent of the total credit rating, and FFO to debt comprises 15% of the total. (Id. at 86.) He also testified that in January 2020, DEC completed its bond issuances for 2020, issuing $500 million 10-year bonds and $400 million 30-year bonds with a weighted average of 2.78%. (Id. at 95.)

DEC witness Newlin testified that Public Staff Newlin Rebuttal Cross Examination Exhibit 5 is DEC's E-1, Item 33-D and 38 filed with DEC's Application. He testified that these E-1 items showed DEC's planned issuance of new debt from 2020 through 2022, totaling $2.1 billion. He testified that with the $900 million already issued in 2020, there remained $450 million in 2021 and $750 million in 2020. He testified that for 2021, the $450 million multiplied by 5 basis points would only add $225,000 a year in interest costs. He further testified that for 2022, the $750 million multiplied by 5 basis points would add $375,000 per year interest costs. (Id. at 99-100.)

Mr. Newlin on cross examination testified that he accepted the Public Staff's calculation that the revenue requirement for the first year would be $86 million less with the Public Staff's recommended coal ash position when compared to DEC's. (Id. at 102.)

DEC witness Newlin further testified that the debt market is good right now, as DEP in August borrowed $700 million at 2.50%. (Id. at 76.) He further testified on cross examination that the S&P Index and Nasdaq both hit all-time highs on Friday, August 21, 2020. (Id. at 113.) He further testified that Duke Energy's current dividend yield is 4.77%. (Id. at 114.)

On redirect, Mr. Newlin testified that Newlin Duke Redirect Exhibit No. 2 was Moody's Duke Energy Carolinas Credit Opinion dated October 31, 2019, which stated that Moody's stable outlook assumes DEC will continue to be allowed to recover the majority of its coal ash remediation spending and that DEC will be able to earn a return on the deferred balance. He testified that this Moody's report also stated that one of the factors that could lead to a DEC downgrade is a decline in the credit supportiveness of DEC's regulatory relationships in North and South Carolina, particularly with regard to coal ash remediation recovery in North Carolina. (Tr. vol. 2, 45-49.)

Upon questions from the Commission, Mr. Newlin agreed that insofar as the Commission has discretion, that discretion is constrained by the North Carolina General Statutes and by decisions of the North Carolina Supreme Court. Mr. Newlin further agreed with Commissioner Clodfelter that the determination of what constitutes a capital investment for rate making purposes in North Carolina is determined from N.C.G.S. 62-133 and from case law interpreting the statute, and it is not determined by Moody's for ratemaking purposes. (Id. at 80-81.)

In response to questions from Commissioner Duffley, Mr. Newlin testified that the Commissions' DEC 2017 rate case provided 230 basis points of support for DEC's December 2019 FFO to debt metric of 26.1%. He testified that the 230 basis points, if removed, would result in FFO to debt of 23.8% He further testified in response to Commissioner Duffley's questions that if the Commission does that anything differently than the 2017 DEC and DEP rate cases regarding coal ash, that the consistency and predictabilities of regulations metric would change. (Id. at 81-94.)

In response to questions from Commissioner Brown-Bland, he testified that in the second quarter Duke Energy earnings conference call, Duke Energy stated that the FFO to debt impact on holding company Duke Energy would be roughly a hundred basis points for negative decisions at DEC and DEP, similar to the DENC rate case order. (Id. at 97.)

John Hinton, Public Staff Director, Economic Research Division, testified on credit metrics in support of the Public Staff's recommendation of a five-year flowback of unprotected excess deferred income taxes. He testified that as noted in Moody's October 31, 2019, DEC Credit Opinion, an FFO to debt ratio between 24% and 26% qualifies for an A rating. He testified that with the Public Staff five-year flowback, the FFO/debt metric would only be below 24% in 2021, and the other metrics are 24% or 25% through 2023. (Tr. vol. 17, 444-48.) Mr. Hinton noted that Moody's Investors Service rated Duke Energy Carolinas' First Mortgage Bonds with the highest rating among the other five electric utility subsidiaries as follows:

Rating Agency	Long-Term Issuer Rating	First Mortgage Bonds
Duke Energy Corporation	Baa1	NA
Duke Energy Carolinas	A1	Aa2
Duke Energy Progress	A2	Aa3
Duke Energy Florida	A3	A1
Duke Energy Indiana	A2	Aa3
Duke Energy Kentucky	Baa1	NA
Duke Energy Ohio	Baa1	A2

(Id. at 450.)

Mr. Hinton testified that a temporary decrease in FFO/Debt would not likely lead to a downgrade to DEC's Aa2 rating on its first mortgage bonds or its A1 senior unsecured bonds. He testified that Moody's, like Standard & Poor's, focuses on net income and the cash flow metric from ongoing and continued operations over time. As such, Moody's averages its financial metrics over three years. Furthermore, Moody's October 31, 2019 Credit Opinion notes that a **sustained** decline in cash flow metrics below 25% could lead to a downgrade. (Id. at 448.)

Public Staff witness Hinton testified that there are other sources of capital available to DEC that would not deteriorate DEC's FFO/Debt metrics. He testified that DEC's filed E-1 Item 23 stated from 2020 through 2023, DEC plans to issue a total of $2.40 billion in long term debt and infuse $4.05 billion to Duke Energy. He testified that an option may exist for DEC to offset some of DEC's debt issuances through a reduction in its planned contributions to its parent, which would help DEC to maintain its credit ratings. He testified that DEC's Aa2 First Mortgage Bonds, and A1 Long-Term Issuer Rating are the highest among Duke Energy and its other five electric utility subsidiaries. (Id. at 449-450.)

Mr. Hinton further testified that Duke Energy Corporation will issue 29 million shares in common stock, which will result in approximately $2.5 billion in net proceeds. He testified that this additional equity could allow DEC to decrease its projected equity infusions up to the parent company, which would alleviate DEC's need to issue the amount of new debt and reduce the possibility of a downgrade. (Id. at 450.)

Mr. Hinton testified that DEC's believes that it is reasonable to expect that a one-notch downgrade by Moody's to Aa3 would increase the investor-required bond yield by 5 basis points. He testified that it is worth noting that Moody's A-rated long-term utility bond yields are the lowest in over thirty years. He further testified that in light of DEC's financial forecasts, it is his opinion that the added cost of debt capital from a downgrade to an Aa3 rating will not be burdensome on DEC. (Id. at 451.)

He testified that Moody's October 31, 2019, Credit Opinion for Duke Energy states the reduction in regulatory lag with DEC's securitization of its storm costs is viewed as credit positive. (Id. at 452.)

On cross examination, Mr. Hinton testified that at the time he wrote his testimony, his belief was that the EDIT issue was the most important issue in the case, and the issue of CCR recovery was not flushed out at the time. (Tr. vol. 2, 109-10.)

Further, Public Staff witness Hinton testified that he did not agree that DEC would be credit downgraded should the Commission approve the Public Staff CCR sharing recommendation. He testified that whether there would be a credit downgrade depends on a multitude of factors, including regulatory support and consistency, regulation of cost recovery methods, the original request and the actual revenue requirements approved by the Commission, and how the approved revenue requirement impacts DEC's finances, both on a cash flow basis and balance sheet basis. Witness Hinton noted that Ms. Shoemaker, Senior Credit Analyst, with Moody's was concerned about the Commission's treatment of coal ash costs; but, he testified that it all gets back to dollars to the Company and that Moody's considers the totality of the rate case. (Id. at 110, 113-14, 116.)

Mr. Hinton testified that the Public Staff does not believe DEC's coal ash management was prudent, and the Public Staff believes in the sharing concept. Mr. Hinton testified that Moody's stated that DEC's stable outlook assumes DEC will continue to be allowed to recover the majority of their coal ash remediation spending. He testified that majority is the issue there. (Id. at 112-14.)

On redirect, Mr. Hinton testified that throughout the Moody's credit opinions, Moody states there could be a downgrade, not that there would be a downgrade. He testified that the credit rating agencies would consider favorably the grid deferral for DEC and DEP of $1.3 billion as acceleration of capital spending recovery, and that the stipulation 52% equity and the 9.6% return on common equity as credit positive. (Id. at 118-120.)

Steven Young, the Executive Vice President and Chief Financial Officer of Duke Energy, testified on rebuttal that to fund the significant capital investments required to provide electric service and to provide effective service to the public, DEC must be able to attract debt capital, and Duke Energy must be able to attract equity capital in the same financial markets utilized by their peers and by other non-regulated businesses. He testified that if access to the capital markets is unduly impaired, DEC's ability to provide customers with safe and reliable electric service at reasonable cost is jeopardized. (Tr. vol. 11, 442.)

Mr. Young testified that neither Duke Energy nor DEC have access to any established "reserves" to pay the carrying costs of their unavoidable need to incur debt (and equity) to support utility operations. He testified that having to simply absorb those carrying costs could have significant negative implications to the financial stability of the enterprise as a whole. (Id. at 443.)

DEC witness Young testified that energy utility operations are often cash flow negative due to the need to serve a growing customer base, repair and maintain existing infrastructure, and immediately respond to all service interruptions such as those caused by major storms. Duke Energy's ability to fund these investments is based upon investor confidence that customer rates will be set at levels that allow all prudent utility operating and financing costs to be recovered. (Id. at 445.)

Witness Young testified in the recent DENC rate case order, the Commission disallowed recovery of a significant portion of the financing costs associated with coal ash basin closure. He testified that disallowances of the recovery of these costs in DEC's case would decrease DEC's cash-flow from operations and increase funding requirements from debt and equity investors, as these costs are unavoidable and will continue to be incurred. He testified that this would impair the credit quality of DE Carolinas and ultimately drive up financing costs and customer rates. (Id. at 448.)

On cross examination, DEC witness Young agreed that N.C.G.S. 62-133(a) states that in fixing rates for any public utility, the Commission shall fix such rates as shall be both fair to the public utilities and to the consumer. (Tr. vol. 3, 42.)

He further testified that he agreed that in N.C.G.S. 62-133 (b) (4), which is the section on the rate of return, one of the items that the Commission should do is to set a rate of return so that the utility could compete in the market for capital funds on terms that are reasonable and that are fair to its customers and to its existing investors. He further testified that language does not mean that the Commission has to set rates and make decisions so that a company has one of the highest credit ratings in existence for public utilities. (Id. at 42.)

Witness Young further testified that the $1.3 billion grid deferral in the stipulation with the Public Staff does not make much difference in cash flow. He testified that the grid deferral makes a big difference in the earnings world and the GAAP earnings world, and that Duke Energy's investors are interested in that in a big way. He further testified that storm cost securitization is going to help DEC recover its storm costs quicker, once DEC issues the bonds. He testified that securitization is a useful tool and a good piece of legislation. (Id. at 50.)

Mt. Young testified that Docket No. E-2, Sub 1219 Hevert Rebuttal Exhibit RBH-14, page 1, contained credit ratings of 31 electric holding companies. He agreed that Duke Energy had an A1 S&P issuer rating, and of the 31 companies, Duke Energy is the second highest company on the list, with only one other company having a higher rating. (Id. at 51.)

He testified that DEC Docket No. E-7, Sub 1214 DEC Hevert Rebuttal Exhibit 14, pages 1 and 2 listed Moody's long-term issuer credit ratings for electric holding and 77 electric operating utilities. He testified that DEC is one of only five Moody's A1 rated, and all but one of the remaining 72 operating companies are lower, which places DEC in the top 6.5%. (Id. at 52-54.)

Mr. Young testified that DEC borrowed $900 million in January 2020, with low rates. This loan preceded COVID-19 and completed DEC's long term debt issuances for 2020. (Id.)

Mr. Young testified that DEC and all of Duke Energy's other operating utilities are cash flow negative and will be in the debt markets each year. (Id. at 61.)

Mr. Young further testified that one of the reasons Duke Energy's stock traded at a discount relative to other electric holding companies is the Atlantic Coast Pipeline. He testified that there remains a discount, and what is sitting in front of Duke Energy is the regulatory regime, particularly in the Carolinas, and particularly around coal ash. (Id. at 63.)

DEC witness Young testified that DEC's E-1 Item 38 showed the DEC long term debt amounts to be borrowed in 2021 at $450 million and in 2022 at $750 million. He testified that DEC's data request response showed that if DEC received a first mortgage bond credit downgrade, it would add five basis points to DEC's future long term debt issuances. He testified that the 5 basis points would add $225,000 annual interest to the $450 million debt issuance in 2021, and $375,000 annual interest to $750 million debt issuance in 2022. (Id. at 69.)

Mr. Young testified that Public Staff Young Rebuttal Exhibit Number 1 is the Duke Energy Earnings Review and Business Update, Fourth Quarter 2019. He agreed this document stated that Duke Energy is delivering on the financial results 2019 earnings per share above the guidance range midpoint, and also it stated that strong year-over-year results represent 7 percent growth. He testified that this document stated that Duke Energy has very strong earnings per share growth, with 2018 to 2019 being 7 percent growth. He testified that the exhibit shows that Duke Energy serves three of the five most vibrant states with Florida one, North Carolina four, and South Carolina five, which are all credit positive. He testified that Duke Energy is not expected to be a significant taxpayer until 2027, which will help the cash flows. Mr. Young testified this Duke Energy document stated that Duke Energy's Total Shareholder Return is an attractive risk adjusted 8 to 10 percent, which he believes to be a very adequate and attractive total shareholder return. He testified that Duke Energy has a top quartile dividend yield and provides low risk returns. (Id. at 73-80.) He testified that Duke Energy's dividend yield as of August 21, 2020, was 4.77%, and Duke Energy on July 6, 2020 announced a two-percent increase in its dividend rate. (Id. at 43.)

Mr. Young also testified that this Fourth Quarter 2019 earnings document stated DEC has $921 million available under the Duke Energy master credit facility. (Id. at 80.) He testified this document showed that as to this North Carolina rate case, the favorable settlements with a broad group of intervenors highlight the constructive regulatory environment in North Carolina. He testified that he believes settlements are constructive as do all their lenders, debt, equity, and credit rating agencies. The document listed the following key settlement issues: 9.6% return on equity, 52 percent equity capital structure, the deferral treatment of the $1.3 billion grid improvement projects, and the flowback of the unprotected EDIT over five years. (Id. at 82-83.)

Mr. Young further testified that Duke Energy was highly confident in achieving a $350 million to $450 million reduction in O&M and other expenses to mitigate the 2020 headwinds. He also testified that Duke Energy plans to settle its $2.5 billion equity issuance in 2020. (Id. at 84.)

In response to questions from Commissioner Brown-Bland, Mr. Young testified that Duke Energy stock was trading at no discount at the end of 2018. He testified during 2019, the following events occurred: the DEQ order for full excavation of all coal ash ponds and the events for the Atlantic Coast Pipeline in the U.S. Fourth Circuit, which were negative. He testified that there was a stock pricing drop in early 2020, when the DENC North Carolina on coal ash was issued. (Tr. vol. 4, 23.)

In response to questions from Commissioner Clodfelter, witness Young testified that DEC has sufficient information to make a showing in this case that the ongoing expenditure for coal ash remediation and coal ash closure are sufficiently knowable and measureable so that these costs could be normalized and included in base rates. (Id. at 28.)

In response to questions from Commissioner Duffley, DEC witness Young testified that he agreed with Moody's statement in its March 30, 2020, credit opinion that in 2020 the anticipated environmental spending, inclusive of coal ash remediation to be $450 million before subsiding to an annual rate of about $200 million in 2021 and beyond. He testified that based upon DEC's settlement with DEQ, coal ash expenditures are going to be more known and measurable going forward. (Id. at 31.)

In response to questions from Commissioner McKissick, Mr. Young testified that in North Carolina, Duke Energy in today's dollars believes $8.5 billion to be the total costs to comply with the settlement with DEQ to excavate roughly 75-80 percent of the coal ash basins and then cap in place the rest. He further testified for coal ash remediation, a run rate could be a useful tool, and a rider mechanism could be an extremely useful tool as well. He also testified that other electric utilities that have credit ratings a notch lower than DEC and DEP are operating and can compete for capital. (Id. at 38-40.)

DEC consultant Steven Fetter testified on rebuttal that DEC issuer credit ratings span the A category between the highest level A1 Stable outlook at Moody's, and the lowest level A-1 Stable outlook at S&P. He testified that a regulated utility should endeavor to hold ratings no lower than Baa1

(Moody's)/BBB+ (S&P), with a longer term goal of moving into or maintaining the A category. (Tr. vol. 26, 67.)

Mr. Fetter testified that the most important qualitative factors are regulation, management and business strategy, and access to energy, gas and fuel supply with timely recovery of associated costs. He testified that credit rating agencies look for the consistent application of sound economic and regulatory principles by utility regulators. (Id. at 68, 70.)

Mr. Fetter testified that the financial community's view of the Commission has been relatively positive. He testified that Regulatory Research Associates (RRA) currently rates the North Carolina regulatory environment, which goes beyond the Commission to also include legislative and executive branch policies, as Average 1, among the top one-third of the 53 regulatory jurisdictions currently rated by RRA. He testified that RRA's view of North Carolina's regulation as overall relatively constructive from an investor viewpoint serves as a positive factor in the credit rating analytical process. (Id. at 74.)

Mr. Fetter testified that Moody's cautions that a DEC credit downgrade could occur if there is a decline in the credit supportiveness of DEC's regulatory relationships, particularly with regards to coal ash remediation recovery in North Carolina. (Id. at 75.)

On cross examination, Mr. Fetter testified that DEC has a Moody's credit rating of Aa2 senior secured and unsecured A1. He accepted earlier testimony that DEC's long term debt consists 81 percent of first mortgage bonds. He agreed that Duke Energy has a Moody's issuer unsecured rating of Baa1. (Id. at 97-99.)

Mr. Fetter testified on cross examination that DEP has a Moody's senior secured rating of Aa3, one notch below DEC. He testified that the DEC and DEP stipulation with the Public Staff stipulated that DEC's May 31, 2020, embedded cost rate of debt was 4.27%, and DEP's was 4.05%, 22 basis points lower. (Id. at 100-102.)

Mr. Fetter testified that nowhere in N.C.G.S 62-133 does it state that rates have to be set to avoid a credit downgrade or that rates have to be set to increase the stock price of utilities, or maintain stock prices of utilities. (Id. at 106-107.)

Mr. Fetter testified that each of the DEC four Commission-approved riders are considered by credit rating agencies as credit positive. He testified that the DEC and Public Staff stipulation, including the grid deferral component, would be viewed positively by the credit rating agencies. He testified that the coal ash decision was a big issue. (Id. at 107-110.)

Mr. Fetter testified that credit rating agencies give great deference to decision making made by a utility with regard to a settlement. He testified that this would include the stipulated 9.6% ROE, the 52% equity capital structure, and the five year flowback for unprotected EDIT. (Id. at 110.)

Mr. Fetter testified that Public Staff Fetter Rebuttal Cross Examination Exhibit Number 1 showed the stock price close for Duke Energy compared to the S&P 500 Index from February 24, 2020, the date of the Commission's DENC general rate case order, and March 3, 2020. He testified that this exhibit showed a drop to March 3, 2020, in the Duke Energy stock price of 6.5%, compared to a drop in the S&P Index of 6.9%. (Id. at 126.)

On redirect, Mr. Fetter stated that he testified in the recent Georgia Power general rate case in which the Georgia Commission approved a return on coal ash costs. (Id. at 136.)

In response to a question from Commissioner Clodfelter, witness Mr. Fetter testified with respect to the 2018 DEC rate order on appeal to the North Carolina Supreme Court, he agreed 100% that the North Carolina Supreme Court should not decide the errors of law based upon how the investment community might react. (Id. at 140-41.) In response to questions from Commissioner Duffley, he testified that a tracker or rider would help get rid of regulatory lag, obviating the need for a return. (Id. at 143.)

In response to questions from Commissioner Hughes, Mr. Fetter testified that in Michigan, where he had been a commissioner, used and useful was not in the Michigan statute. He testified that across the country, used and useful does vary from state to state depending upon the specific language in the law. (Id. at 145-46.)

In response to questions from Commissioner McKissick, Mr. Fetter testified that if the Commission is going to decide on a new standard called culpability, his advice would be to write as much as the Commission can to explain it and explain how it affects these particular circumstances. He further testified that he agreed with witness Young's testimony that if Moody's dropped DEC's credit rating one notch, it would probably be tolerable, but two notches would be problematic. (Id. at 148, 151.)

Conclusion

N.C.G.S. 62-133 sets forth the factors to be considered by the Commission in setting rates for public utilities. N.C.G.S. 62-133 (a) states:

> In fixing rates for any public utility subject to the provisions of this Chapter, other than bus companies, motor carriers, and certain water and sewer utilities, the Commission shall fix such rates as shall be fair to both the public utilities and to the consumer.

N.C.G.S. 62-133 (d) further states that "[t]he Commission shall consider all other material facts of records that will enable it to determine what are reasonable and just rates."

There is no requirement in N.C.G.S. 62-133 that the Commission consider the utility's credit ratings or stock prices when fixing rates, a fact that was conceded by DEC witnesses. However, the Commission must set rates that are reasonable and fair to both its customers and existing investors and should allow the utility to compete in the capital markets on reasonable terms. The record shows DEC's current outstanding debt is rated in the "A" category, which is considered strong investment-grade, representing a lower credit risk to the investor. DEC seeks to maintain financial strength and flexibility to ensure reliable access to capital on reasonable terms and the evidence indicates it has historically done so.

The Commission has weighed the totality of the evidence in the record and concludes the rates established in this order are consistent with this principle. The record contains extensive evidence discussing the relevance and importance of credit ratings, cash flow, stock price, and earnings per share in the management of a utility company. The record contains various expert witness opinions regarding the likelihood of a credit downgrade and the impact of such a credit downgrade on the cost of debt. However, the possibility the Commission's decision may trigger a credit downgrade is a merely that – a possibility and not a certainty. Credit downgrades depend on a multitude of factors, including general regulatory support and consistency, cost recovery methodology, timely recovery of costs, original requested/actual approved revenue requirement, and revenue requirement impact on both cash flow and the balance sheet. The confluence of this multitude of factors following the Commission's order in this case is speculative.

Even if a downgrade were a certainty, the Commission must render a decision based on N.C.G.S. 62-133 and evaluate the ultimate impact on customers and the ability of the utility to access capital markets. The evidence in the record does not show that Duke Energy or its subsidiaries would be unable to access capital markets on reasonable terms following a credit downgrade. The evidence further shows that a credit downgrade would likely result in the cost of debt rising 5 basis points, resulting in a relatively minor impact on rates.

The Commission also concludes from the record that DEC has sufficient levers to use to manage its cash flow going forward to support its credit rating and cash flow metrics by reducing expenses, reducing capital spend, additional equity injection by Duke Energy, and reduced dividend payments up to Duke Energy.

The Commission does not believe it is appropriate to decide individual or collective issues in a general rate case with the goal of achieving a specific credit rating, stock price range, cash flow or similar metric. It is the responsibility of the Commission to decide general rate cases pursuant to N.C.G.S. 62-133 and the decisions of the North Carolina Supreme Court. The Commission decides a variety of individual issues that impact revenue requirement, including the rate base, the rate of return, the capital structure, depreciation, the pro forma revenue levels under current rates, and the reasonable operating expenses. It is the responsibility of the utility's management, to prudently manage the utility in a manner that supports the utility's credit ratings and the stock price.

The Commission has decided the issues in this proceeding based upon the requirements of N.C.G.S. 62-133. The rates fixed by this order are fair to both the public utilities and customers, produce just and reasonable rates, and should allow the utility, through prudent management, to access the capital markets on reasonable terms.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 29-35

[Revenue Requirement]

The evidence for these findings and conclusions is contained in the first and second Public Staff Partial Stipulations, DEC's verified Application and E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

The first and second partial stipulations between the Company and the Public Staff (referred to in the Joint Proposed Order as the Public Staff Partial Stipulations) provide for certain accounting adjustments that the Company and the Public Staff have agreed upon; the revenue requirement effects of the agreed-upon issues are set out in detail in McManeus Supplemental Rebuttal Exhibit 3, Boswell Supplemental and Stipulation Exhibit 1, Schedule 1, and Boswell Second

Supplemental and Stipulation Exhibit 1, Schedule 1 (the Partial Stipulation Revenue Requirement Exhibits), and Public Staff witness Boswell Second Supplemental and Settlement testimony.

McManeus Second Settlement Exhibit 2 shows DEC's revised requested increase incorporating the provisions of the Second Partial Stipulation and the Company's position on the Unresolved Issues. The resulting proposed base revenue requirement of the Company is $414,433,000. Boswell Second Supplemental and Stipulation Exhibit 1 shows the Public Staff's revised recommended change in revenue requirement incorporating the provisions of the Second Partial Stipulation, adjustments related to the audit of the May 2020 update, and a number of downward adjustments reflecting the Public Staff's position on the Unresolved Issues. The resulting proposed base revenue requirement by the Public Staff is an increase in the base rate revenue requirement of $290,049,000, which includes the settled positions of the Company and the Public Staff as well as the unsettled positions of the Public Staff.

Boswell Second Supplement and Stipulation Exhibits 2 and 3 provide for the following amounts of test year pro forma operating revenues, operating revenue deductions, and original cost rate base under present rates: $4,672,431,000 of operating revenues, $3,701,125,000 of operating revenue deductions, and $16,910,528,000 of original cost rate base; and under proposed rates: $4,962,480,000 of operating revenues, $3,769,549,000 of operating revenue deductions, and $16,941,199,000 of original cost rate base. Boswell Second Supplemental and Stipulation Exhibit 1 contains a verified and detailed breakdown of these amounts, including the proformed lead lag impact on the adjustments.

As discussed in the body of this Order, the Commission has approved the Public Staff Partial Stipulations in their entirety and makes its individual rulings on the unresolved issues. After giving effect to the approved Public Staff Partial Stipulations and the Commission's decision on contested issues, an annual base non-fuel revenue increase of $290,049,000 will allow the Company a reasonable opportunity to earn the rate of return on rate base the Commission has found just and reasonable, and finds and concludes that this increase in the level of base rates to be paid by DEC's North Carolina retail customers, resulting in an overall rate of return of 7.042% on jurisdictional rate base and a rate of return on equity of 9.60% using a capital structure of 48% long-term debt and 52% members' equity, is just and reasonable to all parties in light of all the evidence presented.

Further, the Commission finds and concludes that the following amounts of operating revenues (including an annual base non-fuel revenue increase of $290,049,000), operating revenue deductions, and original cost rate base, calculated on Boswell Second Supplemental and Stipulation Exhibit 1, Schedules 2 and 3, are appropriate and reasonable for purposes of setting rates in this proceeding: $4,962,480,000 of operating revenues, $3,769,549,000 of operating revenue deductions, and $16,941,199,000 of original cost rate base. The Commission, therefore, also finds and concludes that for the present case, the agreed-upon accounting adjustments and the unsettled issues between DEC and the Public Staff, outlined in the Second Supplemental and Stipulation Exhibits of

Public Staff witness Boswell, are just and reasonable to all parties in light of all the evidence presented and should be approved.

Boswell Second Settlement and Stipulation Exhibit 1, Schedule 1 provides that the Federal unprotected EDIT amount to be refunded to ratepayers through a levelized rider for a five-year period is $240,875,000 per year, to be adjusted by the Company once the actual amount of EDIT refunded to ratepayers through interim rates has been calculated by the Company. The State EDIT and Federal provisional EDIT to be refunded to ratepayers through a levelized rider for a two-year period is $83,054,000 per year. The decrement riders reduce the total revenue requirement for years 1 and 2 to ($33,880,000), and for years 3 through 5, the total revenue requirement is $49,174,000. The revenue requirements should be updated based upon the actual Federal unprotected EDIT refunded to ratepayers through interim rates.

Due to the need to recalculate the actual Federal unprotected EDIT to return to ratepayers through the rider, the Commission requests that DEC recalculate the required annual revenue requirement in the same format as Boswell Second Supplemental and Stipulation Exhibits 1, 2, and 3, as consistent with all of the Commission's findings and rulings herein, within 10 days of the issuance of this Order. The Commission further orders that DEC work with the Public Staff to verify the accuracy of the recalculations. Once the Commission receives this filing, the Commission will work promptly to verify the calculations and will issue an Order with final revenue requirement numbers.

ISSUED BY ORDER OF THE COMMISSION.

This the ____ day of __________________, 2020.

NORTH CAROLINA UTILITIES COMMISSION

Kimberley A. Campbell, Chief Clerk