A. No exceptional circumstances exist to justify the Grid Rider

DEC in its post-hearing brief, among other things, argues that past cases in which the Commission has created a rider in general rate case proceedings are analogous to the establishment of the Grid Rider in this case, and, therefore, the Commission has the statutory authority to implement the Grid Rider. The Public Staff, AGO, NCSEA, Tech Customers, and other intervenors argue that many of the same cases labeled by DEC as analogous are, in fact, distinguishable, from the issues in the instant proceeding, and, therefore, the Commission does not have the statutory authority to implement the Grid Rider.

As a starting point, the Commission recognizes that certain statutory parameters exist around the authority delegated to it by the Legislature:

> North Carolina Statutes and case law contain explicit limits as to the procedures through which the Commission may revise the rates of a public utility. They are as follows: (1) a general rate case pursuant to G.S. 62-133; (2) a proceeding pursuant to a specific, limited statute, such as G.S. 62-133.2; (3) a complaint proceeding pursuant to G.S. 62-136(a) and G.S. 62-137; or (4) a rulemaking proceeding.

Order Denying Request to Implement Rate Rider and Scheduling Hearing, Docket No. E-7, Sub 849, at p. 18, n.2 (June 2, 2008) (citing State ex. rel. Utils. Comm'n v. Nantahala Power and Light Co., 326 N.C. 190, 195, 388 S.E.2d 118, 121 (1990)). In the instant proceeding – a general rate case pursuant to N.C. Gen. Stat. § 62-133 – the Commission clearly possesses the authority to establish a cost-tracking rider if exceptional circumstances existed to justify such action. Indeed, myriad precedent exists in which the Commission has done just that, even in the absence of an express enabling statute,[34] and the Supreme Court of North Carolina has upheld the Commission's authority to establish a cost-tracking rider when exceptional circumstances, such as a national fuel crisis causing a utility's gas costs to fluctuate unpredictably, warrant such action. See, e.g., State ex rel. Utils. Comm'n v. Edmisten, 291 N.C. 327, 230 S.E.2d 651 (1976) (Edmisten I); State ex rel. Utils. Comm'n v. Edmisten, 291 N.C. 451, 232 S.E.2d 184 (1977) (Edmisten II).

DEC in its post-hearing brief acknowledges that the Commission has in the past recognized the limitations on its authority to create cost-tracking riders in general rate cases; namely, that compelling circumstances must exist to justify special ratemaking

[34] See, e.g., Order Approving Partial Rate Increase and Allowing Integrity Management Rider, Docket No. G-9, Sub 631, at p. 39 (Dec. 17, 2013) (approving an Integrity Management Rider as part of a general rate case decision); Order Approving Partial Rate Increase and Requiring Conservation Initiative, Docket No. G-9, Sub 499 (Nov. 3, 2005) (approving a Customer Utilization Tracker as part of a general rate case decision); Order Granting General Rate Increase and Approving Amended Stipulation, Docket No. E-7, Sub 909 (Dec. 7, 2009) (approving a Coal Inventory Rider as part of a general rate case decision).

treatment.[35] In addressing said limitations, DEC attempts to argue that the magnitude of Power Forward investments, combined with the possibility that regulatory lag of cost recovery for such investments would be detrimental to the Company, are sufficiently exceptional circumstances to justify special ratemaking treatment in the instant proceeding. Accordingly, DEC attempts to argue that the facts in Edmisten I are analogous to DEC's proposed Grid Rider in the instant proceeding. The Commission is unpersuaded by this argument.

Edmisten I approved the use of a fuel adjustment rider in connection with a general rate case. There, the Court noted that the rider at issue "does indeed isolate for special treatment only one element of the utility's cost," but nonetheless approved the additive since it was adopted in connection with a general rate case and was of a nature that merely involved the application of a mathematical formula to the established rates going forward. Edmisten I, 291 N.C. at 340, 230 S.E.2d at 659. Notably distinguishable from the facts in the instant proceeding, however, Edmisten I (1) involved a rider that was adopted in the context of exigent circumstances related to the national fuel crisis in the 1970s, and only after the utility in that case demonstrated a clear connection between recovery of its fuel costs and its financial viability; (2) involved a rider that permitted recovery of core operating costs that now are recoverable under express statutory mechanisms; and (3) did not involve forecasted expenditures or evaluations, but rather permitted rate adjustments by application of a mathematical formula. In other words, the Commission established just and reasonable rates and then adopted a going-forward adjustment mechanism that it found necessary to achieve just and reasonable rates based on the exigencies of the energy crisis, which were beyond the utility's control, impacting the utility's expenditures. Crucially, the Supreme Court of North Carolina recognized in upholding the Commission's establishment of a fuel adjustment clause in Edmisten I that the "Commission, cognizant of its primary duty to fix just and reasonable rates, found upon uncontradicted evidence that the only way it could perform this duty under the facts was to permit use of the fuel clause." Id. at 346. Contrast such findings with those in the instant proceeding, in which the Commission finds and concludes that not only did DEC fail to show that the only way to achieve just and reasonable rates would be to allow special ratemaking treatment of Power Forward costs, but also that the greater weight of the evidence supports the conclusion that to allow the Grid Rider as requested would create unjust and unreasonable rates, in the Company's favor. Furthermore, the Commission finds that none of the facts justifying adoption of the fuel adjustment clause in Edmisten I are present in the instant proceeding. Where Edmisten I addressed fuel costs to be incurred by the utility as an essential component of its utility operations, DEC proposes in the instant proceeding to recover projected, future T&D expenditures for projects not yet identified, which are discretionary on its part. Where Edmisten I was decided in the context of wildly fluctuating fuel costs that threatened the utility's financial viability, here, DEC has complete control over the proposed spending, the rate of spending, and the timing of spending on Power Forward programs; it also has full control over its test year and the timing and frequency of when its applications for a general rate increase are filed. For these reasons, contrary to DEC's argument, Edmisten I cannot be

[35] See, Order Approving Partial Rate Increase, Docket No. G-5, Sub 356, at p. 11 (Sep. 25, 1996).

read to endorse an end-run around the statutory rate-setting mechanisms; to the contrary, central to the Court's holding in Edmisten I was the Commission's conclusion that the rider was critical to the achievement of the statutorily-prescribed rates.

NCSEA and Tech Customers argue in their post-hearing briefs that a case in which the Commission addressed whether a utility could recover the costs of replacing bare steel and cast-iron mains and services through a rider, when the collected funds would be used to pay for expansion facilities, is analogous to DEC's proposed Grid Rider. See In re Pub. Serv. Co. of N.C., Docket No. G-5, Sub 356, pp. 10-13 (Sep. 25, 1996) (PSNC). The Commission agrees. In PSNC, the Commission explained that its legal authority to authorize riders that have the effect of adjusting rates outside of general rate cases is limited to specific "circumstances involving highly variable and unpredictable expense or volume levels beyond the control of the utility." Id. The Commission rejected the proposed rider in PSNC as unlawful for a number of reasons. First, the Commission found that "the cost had not been shown to constitute an unpredictable portion of ... annual construction expenditures" and that the utility "has control as to how much, how often and when the replacement takes place," meaning that the "expenditures are not highly variable or unpredictable, and they are generally controllable" by the utility. Id. Accordingly, the Commission held that implementation of the rider proposed in PSNC did not fall within its authority to establish. The Commission noted a number of other concerns, including the possibility that rates would become unreasonable because the rider "would permit PSNC to recover the cost of the replacement mains without recognition of associated decreases in expenses or increases in revenues," a concern that was magnified "by the sheer magnitude and pace of PSNC's replacement program." Id. The Commission further noted that the rider "would require present ratepayers to pay for certain capital improvements as the funds are expended, rather than as the service is provided," which would "cause current ratepayers to subsidize the cost of serving future generations of ratepayers." Id.

Similarly, as argued by NCSEA and Tech Customers, the Commission agrees that a request for an annually adjustable nonutility generator (NUG) rider is analogous to DEC's proposed Grid Rider. See Order Approving Partial Rate Increase, Docket No. E-22, Sub 314 (Feb. 14, 1991) (VEPCO). In VEPCO, NC Power sought approval to recover future NUG expenses that it was contracted to incur over seven years through a NUG rider, with both deferred accounting and true-ups. In rejecting this request, the Commission found that (1) an annual adjustment for purchases of this type outside of a general rate case was not authorized by statute; (2) there was insufficient justification for treating purchased power expenses any differently from any other expense items in the ratemaking process; and (3) that "the NUG rider mechanism would preclude appropriate regulatory oversight of the Company's overall expenses ... because increases in payments to NUGs for additional capacity and energy could be offset by decreases in other cost of service items" that would not be accounted for without a general rate case. Id. at 19. Based on these "policy and legal concerns," the Commission denied NC Power's request.[36] Id. at 20.

[36] The Commission also noted that the fuel charge adjustment statute had been narrowly construed by the appellate courts, citing State ex rel. Utils. Comm'n v. Thornburg, 84 N.C. App. 482, 353 S.E.2d 413 (1987). There, the Court overturned the Commission's use of an "experience modification factor" to allow

DEC's proposed Grid Rider is analogous to the riders rejected by the Commission in PSNC and VEPCO, and is, accordingly, rejected for the same reasons. With the limited exception of federally-mandated reliability standards, DEC has complete control over the amount and timing of Power Forward expenditures, which thus are entirely predictable. DEC, through its request for the Grid Rider, merely seeks to recover more quickly costs that it has historically recovered without the need for a rider. Furthermore, there is no evidence in the record that without special ratemaking treatment for Power Forward costs, DEC would be unable to remain a strong, financially viable company.

The Commission finds and concludes that cost-tracking riders not specifically established by statute are and should continue to be considered an exception to the general ratemaking principles put in place by the General Assembly and this Commission.[37] In the instant case, there is no specific enabling statute or legislative directive requiring the establishment of the Grid Rider, and, therefore, it falls to the Commission to determine whether the circumstances presented by DEC are exceptional. The Commission finds and concludes that DEC has not presented exceptional or otherwise compelling circumstances to justify special ratemaking treatment of Power Forward costs.

DEC has raised concerns about the regulatory lag for its Power Forward investments. As an initial matter, the Commission notes that regulatory lag is not a new obstacle facing the utilities; rather, it always is present, to a certain extent, in an integrated, investor-owned utility market such as North Carolina. Although DEC in the instant proceeding testified from the perspective of the utility in characterizing regulatory lag as a problem necessitating a solution, it should be pointed out that regulatory lag in certain amounts can give company management an incentive to economize and make more worthwhile investments. Company witnesses Fountain and McManeus stated that while the Grid Rider would alleviate some regulatory lag, it would not be a significant reduction. DEC witness McManeus further stated that the Company did not do an analysis to determine the Company's cash flow with and without the rider; thus, there is no evidence in the record that the Company would be unable to carry out its operations without the requested cost-tracking rider. Therefore, the Commission finds DEC's regulatory lag concerns to be unpersuasive.

CP&L to recover a past under-recovery of fuel costs. Id., 84 N.C. App. at 490, 353 S.E.2d at 418. In light of the holding of the Court of Appeals, the Commission concluded "that an adjustment to base rates outside a general rate case, for which there is no specific statutory authority, to reflect a true-up of NUG expenses would be found unauthorized." Id. at 19.

[37] It should be noted, however, that there exists a plethora of precedent in which the Commission previously has approved the establishment of non-cost tracking riders in its adjudication of general rate cases, like the matter before the Commission in the instant proceeding. It also has approved the establishment of cost-tracking riders in its adjudication of general rate cases, when exceptional circumstances so warranted.

For all of these reasons, the Commission concludes that the Company's request for a Grid Rider should be denied. For the same reasons, the Commission concludes that the modified Grid Riders advanced by the Company in its post-hearing brief and Pilot Grid Rider Agreement and Stipulation, respectively, should also be denied.

B. Power Forward costs do not justify deferral accounting through a regulatory asset

Having already determined that DEC has failed to show that exceptional circumstances justify the establishment of a rider to recover Power Forward costs, the Commission now turns to DEC's request, in the alternative, to allow deferral accounting through the establishment of a regulatory asset for Power Forward costs.

As an initial matter, the Commission recognizes that it has in the past "historically treated deferral accounting as a tool to be allowed only as an exception to the general rule, and its use has been allowed sparingly." Order Approving Deferral Accounting with Conditions, Docket No. E-7, Sub 874, p. 24 (March 31, 2009). In addition, the Commission recognizes that it:

> has also been reluctant to allow deferral accounting because it, typically, equates to single-issue ratemaking for the period of deferral, contrary to the well-established, general ratemaking principle that all items of revenue and costs germane to the ratemaking and cost-recovery process should be examined in their totality in determining the appropriateness of the utility's existing rates and charges.

Id.

Turning now to the issues presented in the instant proceeding, the Commission finds and concludes that the reasons DEC says underlie the need for Power Forward are not unique or extraordinary to DEC, nor are they unique or extraordinary to North Carolina. Weather, customer disruption, physical and cyber security, DER, and aging assets are all issues the Company (and all utilities) have to confront in the normal course of providing electric service. The Commission further finds and concludes that while DEC intends to expend significant funds for T&D projects over the next ten years, a number of the Power Forward programs and projects proposed by DEC to be recovered through the Grid Rider are the kinds of activities in which the Company engages or should engage on a routine and continuous basis. Therefore, the Commission must conclude that Power Forward costs, as proposed in the instant proceeding, are not appropriate to be considered for deferral accounting. In reaching these conclusions, the Commission afforded substantial weight to the testimony of Public Staff witnesses Maness and Williamson, NCSEA witness Golin, and Tech Customers witness Strunk; conversely, the Commission was unpersuaded by DEC witness Simpson's contentions that Power Forward programs are new, novel, or extraordinary.

For example, monitoring, maintaining, and replacing aging equipment with like or new components, regardless of the pace at which these activities are conducted, is part of the Company's ongoing obligation to provide adequate and reliable electric service. In addition, the Commission concludes that new data analytics tools that DEC is using to identify the line segments in its Targeted Underground program do not make the program itself an extraordinary or unique modernization project. Undergrounding of lines is not a new concept, as conceded by DEC witness Simpson. Data analytics, as witness Simpson admitted, is neither a new phenomenon, nor is this current iteration of data analytics likely to remain unchanged for the foreseeable future.

Next, the Commission finds and concludes that the Distribution Hardening and Resiliency program contains, in its entirety, projects that also are within the scope of the Company's normal course of operating and maintaining the distribution grid. Of the categories of projects within this program, witness Simpson conceded that the transformer retrofitting, cable replacement, deteriorated conductor replacement/line rebuild, and pole hardening categories are also included in the Company's customary spend budget for the next five years. The Commission finds and concludes that these project categories are clearly within the Company's normal course of business and are not unique nor appropriate to be deferred.

Further, the Commission finds and concludes that the Transmission Improvements program also consists of projects that replace, rebuild, or improve existing transmission equipment. Federal reliability standards change as necessary to ensure national grid stability and reliability. DEC will be required to make the necessary improvements and modifications to its grid in order to remain compliant with such standards now and in the future, just as it has done for decades. Witness Simpson admitted that meeting such federal standards is customary as part of the Company's Business Expansion/Capacity expenditures. Therefore, these programs, too, are within the Company's ordinary course of business, and thus not appropriate for special ratemaking treatment.

Additionally, the Commission finds and concludes that DEC did not provide sufficient information to show how the Company will determine which Self-Optimizing Grid projects should be assigned to and recovered from the interconnection customers who would benefit the most from this capacity-enhancing and grid-strengthening work. Further, whether the majority of the money allocated to this program is for the replacement of lines deemed inadequate to handle new DERs on the system or new back feed or tie-in lines is unclear from the evidence presented. Either way, the Commission finds that back feed or tie-in lines do not represent new work or grid modernization, as witness Simpson testified. In fact, the addition of these kinds of lines is part of normal operations and the Company has added many of them to the grid in areas within its service territory in the past for purposes of ensuring reliable service to its customers.

Lastly, Enterprise Systems and Communications Network Upgrade programs include upgrades to several systems that the Company already uses to enable data acquisition and analytics to help control the grid. The Commission finds, therefore, that these upgrades are no different than many upgrades to other systems that the Company has made in the past and currently is in the process of making. One example is the Customer Connect program, which is an update to the existing customer information system and not included in Power Forward. The Commission considers these upgrades to constitute part of the ordinary evolution of the Company's business.

For all of these reasons, the Commission finds and concludes that DEC has not satisfied the criteria for deferral accounting treatment of Power Forward costs. In order for the Commission to grant a request for deferral accounting treatment, the utility first must show that the cost items at issue are adequately extraordinary, in both type of expenditure and in magnitude, to be considered for deferral. Second, the utility has to show that the effect of not deferring such cost items would significantly affect the utility's earned returns on common equity. Although it was uncontested by any party that DEC's planned Power Forward spend is extraordinary in magnitude, the Commission is unpersuaded that the entirety of Power Forward programs as proposed are unique or extraordinary. Assuming arguendo that all Power Forward programs as proposed were found to be unique and extraordinary, thus meeting the threshold criteria for consideration of deferral accounting, DEC failed to show that the effect of not deferring Power Forward costs would significantly affect its earned returns on common equity.

The Commission appreciates the Company's undertaking to strengthen and modernize its grid and retool other systems, and encourages its efforts. The Commission recognizes that the costs the Company has identified are substantial and that, by and large, the individual projects are of insufficient length to qualify for CWIP or AFUDC before such projects can be completed and placed in service. Without a rider or an order deferring costs, the Company risks an erosion of earnings from regulatory lag. Likewise, these circumstances promote more frequent, costly rate cases.

Nevertheless, the Commission determines as addressed herein that it does not possess the authority to approve the Grid Rider and that the description of projected projects on this record is insufficient to properly categorize customary spend projects, which the Company must undertake to comply with its franchise obligations, from extraordinary Power Forward or grid modernization projects.

With respect to deferral, the Commission acknowledges that, irrespective of its determination not to defer specific costs in this case, the Company may seek deferral at a later time outside of the general rate case test year context to preserve the Company's opportunity to recover costs, to the extent not incurred during a test period. In that regard, were the Company in the future before filing its next rate case to request a deferral outside a test year and meet the test of economic harm, the Commission is willing to entertain a requested deferral for Power Forward, as opposed to customary spend, costs. Should a collaborative undertaking with stakeholders as addressed herein produce a list of Power Forward projects, such designation would greatly assist the Commission in addressing a requested deferral. Were the Company to demonstrate that the costs can be properly classified as Power Forward and grid modernization, the Commission would seek to expeditiously address the request and to determine that the Company would meet the "extraordinary expenditure" test and conceptually authorize deferral for subsequent consideration for recovery in a general rate case.

The Commission can authorize a test for approving a deferral within a general rate case with parameters different from those to be applied in other contexts. Consequently, with respect to demonstrated Power Forward costs incurred by DEC prior to the test year in its next case, the Commission authorizes expedited consideration, and to the extent permissible, reliance on leniency in imposing the "extraordinary expenditure" test.

Having concluded that the Grid Rider and the Company's alternative request to allow deferral accounting of Power Forward costs should be denied, the Commission need not address the related issues, which also were contested by the intervenors, of cost allocation and rate design of the Grid Rider. DEC should seek recovery of its Power Forward expenditures through the traditional general ratemaking process outlined in N.C. Gen. Stat. § 62-133.

C. <u>DEC shall utilize existing Commission dockets to collaborate with stakeholders</u>

The Commission finds and concludes that several of the intervening parties have raised valid concerns regarding the need for additional transparency and detailed information regarding Power Forward. Although the Commission concluded in this proceeding that Power Forward costs do not warrant special ratemaking treatment, the Commission finds and concludes that additional information would be helpful to the Commission, the Public Staff, and to other intervening and interested parties to better understand Power Forward projects, grid modernization in general, and the cost-effectiveness of such programs.

EDF and NCSEA, in their post-hearing briefs, make compelling arguments that the Commission will not repeat here in support of their position that the Commission should establish a separate, generic docket for the purpose of investigating and evaluating the grid modernization plans of all investor-owned utilities in North Carolina. In addition, the Commission notes that EDF provides a comprehensive overview of grid modernization issues and proceedings, as handled in a number of other jurisdictions. Similarly, the Public Staff requests that DEC be required to include in its Smart Grid Technology Plan filings, required by Commission Rule R8-60.1, more detailed information on Power Forward investments.

While the Commission declines to adopt in its entirety either recommendation advanced by the intervening parties with respect to a separate proceeding to further evaluate some of the issues surrounding Power Forward and grid modernization, the Commission recognizes that there could be value in further collaboration between DEC and the intervening parties on how to resolve these issues, which the Commission expects will continue to be raised until such time as the parties can find a solution within our existing statutory framework. With that said, the Commission directs DEC to utilize an existing proceeding, such as the Integrated Resource Planning and Smart Grid Technology Plan docket, to inform the Commission, and to engage and collaborate with stakeholders to address the myriad of issues raised in the context of Power Forward and the Company's proposed Grid Rider.

D. The Pilot Grid Rider Agreement and Stipulation is disapproved

DEC, EDF, the Sierra Club, and NCSEA (Grid Rider Stipulating Parties) contend that their jointly-filed Pilot Grid Rider Agreement and Stipulation Among Certain Parties (Grid Rider Agreement), the contents of which the Commission will not in this Order summarize in detail, addresses several of the concerns raised by the parties regarding Power Forward and the Grid Rider. The Grid Rider Stipulating Parties further contend that a number of concessions were made both by DEC and its counterparties in order to reach the consensus that culminated with the filing of the Grid Rider Agreement. In essence, the Grid Rider Agreement contains a revised Power Forward proposal on a smaller scale, with a shorter duration and limitations on the Company's spending, at least during the initial three-year pilot period. The Grid Rider Agreement represents a hybrid of the Company's initial cost recovery and alternate cost recovery requests, with most costs being recovered through the Grid Rider during the first three years, followed by deferral of such costs thereafter.

While the Commission appreciates the efforts to resolve some of the contested issues surrounding Power Forward and the Grid Rider, the Commission nevertheless concludes that the Grid Rider Agreement must be disapproved. As an initial matter, even if the Commission hypothetically were to find that the Grid Rider Agreement sufficiently mitigates the valid concerns about Power Forward and the Grid Rider as expressed by the intervening parties throughout this proceeding, the Commission nonetheless still would be required to reach the same conclusion that the law as it currently exists does not allow for the establishment of a rider to recover costs that are predictable and within the utility's control.

In addition to the issue of legality, which in and of itself precludes under the instant circumstances the Commission's consideration of the Grid Rider Agreement, the Commission agrees with NCJC et al. and NC WARN that it would constitute poor policy to allow a partial group of interested parties to develop plans for grid modernization through settlement negotiations that address only certain of a number of contested issues, particularly when the Grid Rider Agreement was filed after the close of the evidentiary record in this proceeding, thus precluding entirely the opportunity for cross examination.

In conclusion, the Commission finds and concludes that the Grid Rider Agreement should be disapproved, for many reasons including the rationale for denying the Company's requests for special ratemaking treatment of Power Forward costs in the first place.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 45-49

The evidence supporting these findings of fact and conclusions is contained in the Company's verified Application and Form E-1, the testimony and exhibits of Company witnesses Fallon, Diaz, and McManeus, CUCA witness O'Donnell, Tech Customers witness Kee, and Public Staff witnesses Metz, Maness, and Boswell, and the entire record in this proceeding.

In Docket No. E-7, Sub 819, which has been consolidated with this general rate case, the Company requests Commission approval of its decision to cancel the Lee Nuclear Project pursuant to N.C. Gen. Stat. § 62-110.7(d). In this general rate case, the Company requests permission to move the adjusted balance of the Lee Nuclear Project development costs from CWIP Account 107 to regulatory asset Account 182.2 and to recover the project development costs in rates by amortizing such costs over a 12-year period. The Company also requests that the unamortized balance of such costs be included in rate base to recover a net-of-tax return on the unamortized balance.

DEC witness Fallon testified that in its 2005 and 2006 Integrated Resource Plans (IRPs), the Company identified the need for significant capacity additions by summer 2016 and found nuclear generation to be a least cost supply-side alternative. Tr. Vol. 10, p. 182. In March 2006, DEC announced that it had selected the site for Lee in Cherokee County, South Carolina, to evaluate for possible nuclear expansion. Tr. Vol. 10, p. 183. On September 20, 2006, the Company filed a request in Sub 819 for a declaratory ruling for authority to recover the North Carolina allocable portion of necessary costs and obligations to be incurred through December 31, 2007. On March 20, 2007, the Commission issued its Order Issuing Declaratory Ruling (2007 Order), in which the Commission determined that it was appropriate for DEC to pursue project development work up to $125 million through December 31, 2007, for the Lee Nuclear Project and that DEC could recover the project costs in the manner determined to be appropriate by the Commission and allowed by law.

On January 1, 2008, N.C. Gen. Stat. § 62-110.7 went into effect. This statute provides for Commission review of a utility's decision to incur nuclear project development costs. Under this statute, prior to filing an application for a Certificate of Public Convenience and Necessity (CPCN) in North Carolina or another state, a public utility may request that the Commission review its decision to incur nuclear project development costs. Under N.C. Gen. Stat. § 62-110.7(a), project development costs are defined as:

> all capital costs associated with a potential nuclear electric generating facility incurred before (i) issuance of a certificate under G.S. 62-110.1 for a facility located in North Carolina or (ii) issuance of a certificate by the host state for an out-of-state facility to serve North Carolina retail customers, including, without limitation, the costs of evaluation, design, engineering, environmental analysis and permitting, early site permitting, combined operating license permitting, initial site preparation costs, and allowance for funds used during construction associated with such costs.

Generally speaking, under N.C. Gen. Stat. § 62-110.7(b), the Commission shall approve a utility's decision to incur project development costs if the utility demonstrates that the decision to incur such costs is reasonable and prudent; however, the Commission does not consider the reasonableness or prudence of any specific activities or items of costs until a rate case proceeding. North Carolina Gen. Stat. § 62-110.7(c) provides that reasonable and prudent project development costs shall be included in the utility's rate base and be fully recoverable through rates in a general rate case. However, if the project is cancelled, as has occurred in this case, N.C. Gen. Stat. § 62-110.7(d) allows the utility to recover all reasonable and prudently incurred project development costs in a rate case amortized over the longer of five years or the period during which the costs were incurred, which in this case is 12 years. It should be noted that while N.C. Gen. Stat. § 62-110.7(c) provides for rate base treatment of project development costs and therefore includes a return, N.C. Gen. Stat. § 62-110.7(d), applicable to cancelled projects, only requires amortization of the costs and does not mention, and certainly does not mandate, a return.[38]

Witness Fallon testified that on December 7, 2007, DEC filed an Application for Approval of Decision to Incur Continued Generation Project Development Costs. Tr. Vol. 10, p. 186. Specifically, DEC sought approval of its decision to incur the North Carolina allocable share of an additional $160 million of Lee Nuclear Project development costs during 2008 and 2009 to maintain the ability to begin nuclear construction to serve customers in the 2018 timeframe as identified in the Company's 2007 IRP. Tr. Vol. 10, p. 187. The Commission approved DEC's request on June 11, 2008 (2008 Order). Tr. Vol. 10, p. 188.

On November 15, 2010, DEC filed an Amended Application for Approval of Decision to Incur Nuclear Generation Project Development Costs seeking approval to incur an additional $229 million of project development costs (later revised to $287 million), for a total of $459 million (including AFUDC) for the period January 1, 2010 through December 31, 2013, to allow Lee Nuclear to remain an option to serve customers in the 2021 timeframe. Tr. Vol. 10, pp. 188-89. The Commission did not approve DEC's request as filed, but in its Order dated August 5, 2011 (2011 Order), the Commission ruled that the nuclear project development costs incurred on or after January 1, 2011, would be subject to a not-to-exceed cap of the North Carolina allocable portion of $120 million and that its approval granted was limited to those nuclear project development costs that must be incurred to maintain the status quo with respect to the Lee Nuclear Project, including DEC's application for a combined operating license (COL) at the Nuclear Regulatory Commission (NRC). Tr. Vol. 10, pp. 190-91. As in the 2008 Order, the Commission allowed DEC to continue provisionally accruing AFUDC, stated that the Company would need to request regulatory asset treatment for any abandoned project development, and required DEC to continue filing semi-annual reports detailing activities and expenditures. Tr. Vol. 10 p. 191. The Commission did not retroactively approve the decision to incur project development costs during 2010. DEC did not seek further project development cost approval orders after the 2011 Order.

DEC witness Fallon testified that the Company incurred costs for the development of the Lee Nuclear Project of approximately $542 million through June 30, 2017. The

[38] The return at issue here is the return associated with the unamortized balance of a plant that has been abandoned, the costs of which, if not deferred for potential rate recovery through amortization, would otherwise be written off as of the date of abandonment as a loss on the income statement. It is not the return normally accrued on a plant's cost balance during construction, the allowance for funds used during construction (AFUDC), which is included in the definition of "project development costs" set forth in N.C. Gen. Stat. § 62-110.7(a).

costs are composed of the following categories: Combined Operating License Application (COLA) Preparation, NRC Review and Hearing Fees, Pre-Construction and Site Preparation, Land and Right of Way Purchases, Supply Chain, Construction Planning and Engineering, Operational Planning, Post COL, and AFUDC ($232 million of the $542 million), as reported in DEC's semi-annual reports to the Commission. Tr. Vol. 10, p. 178; Tr. Vol. 11 p. 19. He stated that in order to "maintain the status quo", DEC exceeded the cap set in the 2011 Order in 2013. Tr. Vol. 10, p. 192. Specifically, witness Fallon indicated that DEC began limiting its activities to only those activities and costs necessary to preserve the option of bringing the plant online around the 2021 target date, did not order equipment, and wound down non-essential site specific work and construction planning activities. Tr. Vol. 10, p. 208. He noted that the Company continued to substantially complete the design of the commercial buildings so that they could be completed in time to meet the 2021 date identified in the IRP. Id. According to witness Fallon, the Company completed its contractual commitments in areas no longer necessary to maintain the status quo and narrowed the scope of work to reduce costs. Further, he indicated that the Company wound down contracts so to preserve the work to be efficiently resumed at a later date. Id.

Witness Fallon also noted that the Company submitted a COLA with the NRC for two Westinghouse AP1000 Pressurized Water Reactors on December 13, 2007. Tr. Vol. 10 p. 180. He noted that a number of factors, many outside the control of DEC, led to a longer licensing period than originally anticipated. Tr. Vol. 10, p. 192. Witness Fallon stated that on December 19, 2016, the NRC issued a COL for the Lee Nuclear Plant allowing DEC to construct the units and to operate them for 40 years. Id. The licenses are renewable for an initial 20-year period and possibly a second 20-year period. Tr. Vol. 10, p. 181. Witness Fallon stated that under the terms of the COL, DEC is not compelled to build and operate the nuclear plant. Id.

Witness Fallon noted that the IRPs between 2006 and 2016 identified Lee Nuclear as a cost effective option to meet the need for base load, but the date of the earliest need for each unit moved to 2026 and 2028 in the 2016 IRP. Tr. Vol. 10, p. 185. He pointed out that through the 2016 IRP, Lee Nuclear Project continued to be least-cost carbon free generation option for customers. Tr. Vol. 10, p. 193. In addition, witness Fallon noted that having the COL for the Lee Nuclear Project would reduce the lead time required to license new nuclear plant at the site. Id. Witness Fallon also indicated that in DEC's latest IRP, the first Lee Nuclear unit would be needed no earlier than 2031, and then only in a carbon-constrained scenario with the assumption of no existing nuclear relicensing. Tr. Vol. 24, pp. 61-62.

In regard to the request to cancel the Lee Nuclear Project, witness Fallon said that since issuance of the COL, the risks and uncertainties in regard to beginning construction have become so great that cancellation was in the best interest of customers. Tr. Vol. 10, p. 195. He noted that in early 2017, Westinghouse announced its plans to exit the nuclear plant construction business, and then, on March 29, 2017, announced its bankruptcy. Tr. Vol. 10, p. 196. Additionally, the first two plants being constructed with AP1000 reactors, in South Carolina (V.C. Summer Project) and Georgia (Vogtle Project), have cost billions of dollars more than originally estimated and have faced significant delays. Id. Witness Fallon stated that the Westinghouse bankruptcy and the decision to stop construction at the V.C. Summer Project led to great uncertainty about the cost, schedule, and execution of construction for future nuclear projects, directly impacting the Lee Nuclear Project. Tr. Vol. 10, p. 198. Therefore, due to these uncertainties and risks, as well as projected low natural gas prices and uncertainty about carbon emission costs, witness Fallon testified that the Company thought that it is not in customers' best interest to construct and operate Lee Nuclear before the end of the next decade. Id. As a result, the Company requests to cancel the project, but maintain the COL. Tr. Vol. 10, pp. 198-99. Witness Fallon indicated that there would be post-COL costs of approximately $700,000 per year so the Company could make annual filings with the NRC and maintain the property. Tr. Vol. 11, p. 72.

DEC witness Diaz testified that in his experience as an NRC Commissioner, including serving as Chairman, he was thoroughly familiar with the AP1000 design and with the NRC licensing process. Tr. Vol. 10, p. 221. In reviewing DEC's decision to pursue the preparation of a COLA in 2005 and submit it to the NRC on December 13, 2007, witness Diaz stated DEC had chosen the optimal path to pursue licensing by using the NRC's new nuclear reactor licensing protocol pursuant to 10 C.F.R. Part 52 Rule (Part 52) (Tr. Vol. 10, p. 223), but that significant time was necessary due to Part 52 being untested. Tr. Vol. 10, p. 233. He noted that when DEC submitted its COLA, the NRC schedule provided for a 42-month period between submission of the application and receipt of the COL, though there was an expectation of a longer period due to the number of applications. Id.

Witness Diaz explained that the process to license the Lee Nuclear Project was delayed for a number of reasons outside of DEC's control, including delays related to the NRC's review of the Yucca Mountain licensing application (Tr. Vol. 10, pp. 235-36), the Waste Confidence Rule (Tr. Vol. 10, pp. 236-37), the Fukushima Dai-ichi accident (Tr. Vol. 10, pp. 238-39.), and the new Seismic Source Characterization. Tr. Vol. 10, p. 240. Additionally, delays occurred as DEC updated its COLA from Rev 16 to Rev 19 of the AP1000 (Tr. Vol. 10, pp. 241-42), changed the location of the reactor based on it improving reactor building stability and being more economical to construct (Tr. Vol. 10, pp. 242-43), added a make-up pond for cooling water due to the limited water in the main cooling source (Tr. Vol. 10, pp. 243-44), and amended the COLA to revise the cooling tower design. Tr. Vol. 10, p. 244. Witness Diaz testified that he believed that DEC acted prudently in making each of these changes and thus the resulting delays were reasonable. Tr. Vol. 10, pp. 241-44. He also noted difficulties associated with using Part 52 licensing that slowed the process, including requests for additional information (RAIs) and generic design issues, as well as design errors in Rev 19, all of which witness Diaz concluded DEC had managed in a reasonable and prudent manner. Tr. Vol. 10, pp. 245-48.

Witness Diaz also reviewed the cost breakdown for the COL and project-related costs for the Lee Nuclear Project and found that they compared favorably to the costs incurred by Florida Power & Light (FP&L) for its Turkey Point Units 6 and 7 COL. Tr. Vol. 10, p. 249. He discussed the disadvantages that would have resulted if DEC had suspended its efforts to license Lee Nuclear, the value of the Lee Nuclear COL, the advantages of DEC's licensing-first approach, and the reasonableness of the selection of the AP1000 design. Tr. Vol. 10, pp. 250-51. Witness Diaz concluded that based on his experience, DEC's approach to licensing and managing the Lee Nuclear Project, and its decision to extend the targeted operation dates, were reasonable and consistent with best practices. Tr. Vol. 10, p. 253. He further determined that the project costs incurred were reasonable and prudent. Tr. Vol. 10, p. 234.

DEC witness McManeus testified that the Company proposed amortizing the accumulated construction work in progress (CWIP) balance related to the Lee Nuclear Project. Tr. Vol. 6, p. 257. In her direct testimony, witness McManeus stated that the adjusted CWIP balance reflecting the actual costs incurred through June 30, 2017 and incorporating estimated additional expenditures through March 31, 2018, was $353.2 million and $527.1 million on a North Carolina and system basis, respectively. Id. She noted that non-depreciable land and its associated AFUDC had been removed from the balance. Id. This results in an annual revenue requirement of $52.6 million, consisting of an annual amortization expense over 12 years of $29.5 million, and a net of tax return on the unamortized balance of $23.1 million. Id.

CUCA witness O'Donnell testified that DEC's exceedance of the cap set in the 2011 Order without coming to the Commission for approval of its decision to incur further project development costs was an example of DEC's tendency to "beg forgiveness than to ask permission." Tr. Vol. 18, p. 51.

Tech Customers witness Kee testified regarding the Lee Nuclear Project. Tr. Vol. 18, pp. 164-65. Witness Kee addressed various issues surrounding whether DEC should recover costs incurred to develop the Lee Nuclear Project. Id. at 165-66. Witness Kee recommended that (1) DEC should only recover those costs incurred up to December 31, 2009, if those costs were within the amounts preauthorized by the Commission; (2) DEC should not recover any costs incurred during 2010; and (3) the Commission should completely disallow or significantly limit any recovery of costs incurred between January 1, 2011 and June 2017. Id. at 204-05.

As an alternative to completely disallowing cost after January 1, 2011, witness Kee divided the Lee Nuclear Project costs into two categories: Type 1 and Type 2. Id. at 181. Type 1 costs are "related to the NRC review of the Lee COL application." Id. Type 2 activities are "at most, indirectly related to the NRC COL review process, but were undertaken in preparation for the eventual construction and operation of the Lee nuclear project." Id. at 182. Witness Kee posited that Type 1 activities fall within the meaning of "maintain the status quo" under the 2011 PDO, and Type 2 activities represent expenditures beyond the status quo. Id. at 181. His alternative recommendation was to allow only those costs after January 1, 2011 that relate to Type 1 activities and are less than the amount approved in the 2011 PDO. Id. at 205.

Public Staff witness Metz testified regarding the Company's request for cancellation of the Lee Nuclear project and recovery of the project development costs.

He noted that the Public Staff hired as a consultant, Global Energy & Water Consulting, LLC, a firm with extensive experience with nuclear construction activities and NRC application processes, to (1) review the details of all costs charged to all the capital accounts assigned to engineering, licensing, and regulatory compliance for the Lee Nuclear Project; (2) review the decisions to begin, continue, and cancel the project, as well as issues with the AP1000 design, Westinghouse, and Westinghouse's owner, the Toshiba Corporation; (3) review DEC's project planning decisions; (4) compare the costs incurred to those of other utilities; and (5) identify any costs that were not reasonably or prudently incurred. Tr. Vol. 23, pp. 31-32. The Public Staff also reviewed the activities and costs internally. Tr. Vol. 23, p. 32. Based on the Public Staff's review as assisted by the consultants, the Public Staff found that with one exception involving design costs for a visitors' center, the costs incurred (not including AFUDC, which was reviewed by Public Staff witness Maness) were reasonably and prudently incurred based on information known at the time. Tr. Vol. 23, pp. 32-33. Witness Metz recommended that costs incurred for the architectural and engineering design of a visitors' center be disallowed on the basis that under the dictates of the 2011 Order, the costs did not directly support the COLA process at the NRC and were not necessary to maintain the status quo at that time. Tr. Vol. 23, pp. 33-34. This recommendation results in a disallowance of $507,009 on a system basis, exclusive of AFUDC. Tr. Vol. 23, p. 36.

Public Staff witness Maness testified that on behalf of the Public Staff, he investigated the reasonableness of the accrual of the AFUDC costs included in DEC's project development costs, and particularly DEC's dates for beginning and ending the accrual of AFUDC. Tr. Vol. 22, p. 100. Based on his review, witness Maness found the date on which DEC began accruing AFUDC to be reasonable, but recommended that AFUDC accrual end as of December 31, 2017, instead of the May 1, 2018, date estimated by DEC. Id. He testified that under FERC Accounting Release No. 5, AFUDC accruals must cease if construction is suspended or interrupted. Tr. Vol. 22, p. 101. Based on discussions between DEC and the Public Staff, witness Maness stated that the Company had confirmed that work on the Lee Nuclear Project had ended as of December 31, 2017, and that the Company had ceased accruing AFUDC at that time. Tr. Vol. 22, p. 102. He noted that removal of the estimated 2018 AFUDC from the costs proposed for Lee Nuclear recovery resulted in a $9 million adjustment. Id.

Public Staff witness Boswell contended that the Commission should adhere to its longstanding position that no adjustment should be allowed which would effectively enable the Company to earn a return on the unamortized balance of the construction costs of a nuclear plant that had been abandoned. Tr. Vol. 26, p. 140. She argued that the Commission has found in past cases that this treatment fairly allocated the loss between the utility and customers, and that customers should not bear all the risk of the cancelled plant. Id.

In his rebuttal testimony, witness Diaz disagreed with witness Kee's stratification of costs into two categories on the basis that both types of costs were necessary for the Company to adhere to the 2011 Order and to have the Lee Nuclear option available to meet the dates for need projected in DEC's IRPs. Tr. Vol. 26 p. 181. He noted that DEC could not have obtained the COL without exceeding the limits in the 2011 Order. Tr. Vol. 26, p. 182. Witness Diaz further testified about the value of the COL obtained by DEC. Tr. Vol. 26, pp. 186-88.

In rebuttal, Company witness Fallon testified that the Company did not oppose the recommendation of witness Maness to end the accrual of AFUDC for Lee Nuclear at December 31, 2017. Tr. Vol. 24, pp. 32, 33. In regard to witness Metz's proposed disallowance for the costs associated with the architectural and engineering of a visitors' center, witness Fallon explained the reasons why DEC sought to construct a visitors' center as one of the buildings with early design work, but conceded that witness Metz's conclusion to recommend a disallowance for these costs was reasonable. Tr. Vol. 24, p. 34.

Witness Fallon opposed the recommendation of Public Staff witness Boswell that DEC should not receive a return on the unamortized balance of the Lee Nuclear costs and associated accumulated deferred income taxes (ADIT). He noted that while witness Boswell referred to the costs of Lee Nuclear as having been prudently incurred, the financing costs of the unamortized balance were also prudently incurred costs. Tr. Vol. 24, pp. 34-35. Witness Fallon pointed out that N.C. Gen. Stat. § 62-110.7 does not prohibit DEC from receiving a return on the unamortized balance of prudently incurred costs. Tr. Vol. 24, p. 36. He argued that witness Boswell had not considered the specific facts of this case in making her recommendation of no return, including the fact that the Company had obtained a COL, the highly dynamic energy future, the advantages of maintaining fuel diversity, and the uncertainty of nuclear relicensing. Tr. Vol. 24, pp. 37-39. Witness Fallon also detailed the steps the Company took to mitigate the risks of the project. Tr. Vol. 24, p. 39.

In regard to the testimony of Tech Customers witness Kee, witness Fallon disagrees with the contention that all nuclear development costs must be approved or authorized in advance under N.C. Gen. Stat. § 62-110.7 to be recoverable. Tr. Vol. 24, p. 40. Witness Fallon noted that while the project development orders (PDOs) issued in Sub 819 have specific authorizations, they do not foreclose the possibility that DEC may recover costs outside of the strictures of those Orders. Tr. Vol. 24, p. 41. He also stated that utilities are permitted, but not required, to seek approval of the decision to incur project development costs under N.C. Gen. Stat. § 62-110.7, and that the Commission did not approve DEC's request for approval to incur Lee Nuclear costs in 2010, but it made no finding as to their recoverability. Id. Witness Fallon testified that DEC had exceeded the spending cap set in the 2011 Order. However, he testified that DEC interpreted the 2011 Order as requiring the Company to limit its spending to amounts necessary to preserve the option of building Lee Nuclear so that it would be available to meet the target dates of need set out in DEC's IRPs, including maintaining an active COLA at the NRC. Tr. Vol. 24, p. 44. In order to maintain this active COLA status, witness Fallon explained that DEC had to continue its permitting, pre-construction, engineering, design, construction planning, and operational planning activities to maintain the status quo. Tr. Vol. 24, p. 45. Further, witness Fallon testified that it was necessary for DEC to continue its efforts in many areas to avoid signaling to the NRC that DEC was not actively pursuing the Lee COL, which could have resulted in termination of the review process by the NRC prior to the issuance of the COL. Id.

On cross-examination, witness Fallon identified Tech Customers Fallon Rebuttal Exhibit 1 as an internal presentation made in February 2012 to the Company CEO's staff by himself and the nuclear development staff regarding the future of the Lee Nuclear Project. Tr. Vol. 24, p. 54. The exhibit showed the projected dollars spent that exceeded the limits of PDOs issued by the NCUC and the South Carolina Public Service Commission. Tr. Vol. 24, p. 56. The presentation indicated that filing for a subsequent PDO would put the NCUC in a "difficult position" as James E. Rogers, the CEO during the 2011 proceeding had testified that DEC would not proceed with Lee Nuclear unless the North Carolina General Assembly had enacted legislation allowing DEC to receive CWIP costs through a specified cost recovery process.[39] Tr. Vol. 24, p. 57. The presentation also noted the negative impact on the Lee Nuclear business case of projected low natural gas prices. Id. The presentation also pointed out the negative effect on the Lee Nuclear project that would result from a rejection of a further request for approval to incur nuclear development costs. Tr. Vol. 24, p. 58. Based on these factors, Nuclear Development recommended in 2012 that the Company not seek an additional PDO. Id. The Company also had another internal meeting in early 2013 where it again decided against pursuing a further PDO for similar reasons, as well as delays occurring with the NRC process. Tr. Vol. 24, pp. 62-64. Following the merger of Duke Energy Corporation and Progress Energy, Inc., a third senior management meeting was held in November 2013 to consider whether to pursue a PDO. Tr. Vol. 24, pp. 65-66.

Witness Fallon agreed that one of the purposes of N.C. Gen. Stat. § 62-110.7 is to help alleviate some portion of the risk that certain costs incurred for nuclear project development activities may be found to be imprudent. Tr. Vol. 24, p. 71. Witness Fallon stated that he was the Company witness supporting DEP's request in its recent rate case to recover COLA costs of approximately $45.3 million for its cancelled Harris Nuclear project. Tr. Vol. 24, p. 74. In that case, DEP did not seek a return on the unamortized balance of the costs for the COLA for the cancelled Harris Nuclear project. Tr. Vol. 24, p. 75. However, witness Fallon argued that the Harris Nuclear and Lee Nuclear projects are different because DEC had sought approval for the Lee Nuclear Project under N.C. Gen. Stat. § 62-110.7, the Lee Nuclear project had progressed beyond the development stage to receipt of a COL, and that the investor risk differed due to the amount of spending and the scope of activities. Tr. Vol. 24, pp. 75-77. Finally, witness Fallon acknowledged that while having the COL means that DEC may use its option to build the Lee Nuclear plant when the time is right, the time may never be right. Tr. Vol. 24, p. 82.

In her rebuttal testimony, Company witness McManeus noted that the Company did not oppose the recommendations of Public Staff witness Metz to remove certain costs associated with the design of a visitors' center from the Lee Nuclear costs or Public Staff witness Maness to remove AFUDC for the months after December 2017. Tr. Vol. 26,

[39] This testimony by Mr. Rogers was one of the factors cited by the Commission in its decision to issue only a limited approval of DEC's decision to incur project development costs in the 2011 Order.

p. 310. She testified that the Company did oppose the adjustment recommended by Public Staff witness Boswell to remove the unamortized balance of deferred project development costs and the associated ADIT from rate base, thereby preventing the Company from earning a return on the unamortized balance. Id. Witness McManeus argued that the Commission should consider that the Lee Nuclear project costs were financed by investors and should appropriately be in rate base. Tr. Vol. 6, p. 311. According to witness McManeus, if the Commission determines that the Lee Nuclear costs were incurred prudently, it should include those costs in rate base, thereby allowing the Company to earn a return on the unamortized balance. Id. On cross-examination, witness McManeus agreed that the decision to allow the Company to earn a return on cancelled plant was within the Commission's discretion. Tr. Vol. 8, p. 232. She further agreed that once the amortization of Lee Nuclear was completed, it would be inappropriate for the Company to re-establish the asset and thus recover it from the customers again. Tr. Vol. 26, p. 110. She indicated that if recovery of Lee Nuclear costs were allowed, DEC would have a regulatory asset that would be amortized over the period allowed, and then in DEC's next rate case, the balance of the regulatory asset would be addressed. Id.

Discussion and Conclusions on Lee Nuclear

A. Recovery of Costs

In regard to specific items of cost, the Commission agrees with Public Staff witness Metz that costs incurred for the architectural and engineering design of a visitors' center did not directly support the COLA process at the NRC and were not necessary to maintain the status quo at that time as directed by the 2011 Order. As such, these costs should be disallowed. The Commission also agrees with Public Staff witness Maness that accrual of AFUDC on the project should have stopped after all substantive work on the project had come to an end by December 31, 2017. As noted above, DEC did not contest either of these two proposed adjustments.

As noted above, Tech Customers witness Kee recommended disallowance of the costs incurred in 2010 and the costs in excess of the limit set in the 2011 Order. In its proposed order, Tech Customers supports this position. NC WARN supports the recommendations of witness Kee in its brief. In its proposed order, the AGO argues that given the evidence challenging the reasonableness and prudence of DEC's expenditures on and after January 1, 2011, and DEC's failure to provide details sufficient to identify what it would have cost to maintain the status quo, the costs incurred on or after January 1, 2011 for new development activities should be disallowed. The Commission finds that witness Kee's recommendation appears to be based on a misinterpretation of N.C. Gen. Stat. § 62-110.7. First, N.C. Gen. Stat. § 62-110.7(b) includes the word "may" indicating that it is at the utility's discretion whether it will seek to incur approval of its decision to incur nuclear project development costs under the statute. Costs for which preapproval is not sought, such as those in 2010, are still appropriately considered in a general rate case proceeding under N.C. Gen. Stat. § 62-133, including the prudence of the decision to incur the costs. Similarly, the costs that were incurred outside the cap set in the

2011 Order are appropriately considered in this proceeding. N.C. Gen. Stat. § 62-110.7 provides a utility approval only of its decision to incur nuclear development costs under the circumstances at the time of the decision. No particular costs are approved or found to be reasonable, and circumstances can change after issuance of the approval making it no longer reasonable to incur costs. As discussed by DEC witness Fallon, DEP elected to pursue development of its Harris Nuclear project without obtaining approval under N.C. Gen. Stat. § 62-110.7 and the Commission approved recovery of the costs of the COLA in DEP's recent rate case without regard to whether DEP had received approval under N.C. Gen. Stat. § 62-110.7. The Commission further disagrees with witness Kee that what he categorizes as Type 2 costs should be disallowed because they were not necessary to maintain the status quo. The Commission finds that, except as discussed above in regard to the visitors' center and AFUDC, the costs were reasonably and prudently incurred to maintain the status quo and ensure that Lee Nuclear would be an option for the dates of projected need in DEC's IRPs.

B. Cancellation of the Lee Nuclear Project

The Company has stated that it seeks Commission approval to cancel the Lee Nuclear Project. The Commission agrees with DEC witness Fallon that the risks and uncertainties in regard to beginning construction of the Lee Nuclear Project, including the Westinghouse bankruptcy, issues with Toshiba, the cancellation of the Summer project, overruns and delays at the Vogtle project, as well as natural gas prices and potential carbon emissions regulation, have become so great that cancellation is in the best interest of customers. Further, DEC's 2017 IRP does not show a need for the first unit until 2031, and then only under a number of assumptions.

While no party expressed opposition to DEC's decision to cancel the Lee Nuclear Project, in their proposed orders, the Tech Customers and the Public Staff question the authority of the Commission to cancel the project noting that the Commission had never granted the project a CPCN under N.C. Gen. Stat. § 62-110.1, nor had any other state approved the project. While there may be merit to such observations, suffice it to say, the Commission finds and concludes that adequate justification exists to support cancellation of the Lee Nuclear Project and that DEC's decision to cancel the project is reasonable and prudent and in the public interest.

C. Return on Unamortized Balance

The Commission is also in agreement with Public Staff witness Boswell's position concerning the Company's request to earn a return on the unamortized balance of the costs. Company witness McManeus acknowledged on cross-examination that in the cases of Duke Power Co., Docket No. E-7, Sub 338, 72 N.C.U.C. 173 (Nov. 1, 1982); Carolina Power & Light Co., Docket No. E-2, Sub 461, 73 N.C.U.C. 114 (Sept. 19, 1983); and Carolina Power & Light Co., Docket No. E-2, Sub 481, 74 N.C.U.C. 126 (Sept. 21, 1984), all involving abandoned nuclear plants, the Commission had refused to allow a return on the unamortized balance. She further stated that she knew of no other case decided since 1982 approving a return on the unamortized balance; and neither the Public

Staff nor the Commission has been able to identify any such case. The Commission's 1982-84 decisions denying a return on the unamortized balance of nuclear plant costs have been reaffirmed in cases such as Carolina Power & Light Co., Docket No. E-2, Sub 537, 78 N.C.U.C. 238 (Aug. 5, 1988), aff'd in part, rev'd in part on other grounds, and remanded sub nom. State ex rel. Utils. Comm'n v. Thornburg, 325 N.C. 484, 385 S.E.2d 463 (1989). See also, State ex. rel. Utils. Comm'n v. Thornburg, 325 N.C. 463, 480-81, 385 S.E.2d 460-61 (1989), which held that the Commission had the legal authority to deny a return on the unamortized balance of nuclear cancellation costs.

In the Commission's judgment, the decisions it has reached on this issue since 1982 are correct and should be followed in this case. The Commission has repeatedly decided that the loss experienced upon the cancellation of a nuclear plant should be shared between the shareholders and the ratepayers. As the Commission stated in its Order in Duke Power Co., Docket No. E-7, Sub 358, 73 N.C.U.C. 255, 266 (Sept. 30, 1983), when addressing the loss associated with the Cherokee Nuclear Plant (Lee's precursor abandoned nuclear project at the same site):

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

See also, In re Carolina Power & Light Co., Docket No. E-2, Sub 461, 55 P.U.R. 4th 582, 601 (1983).

Accordingly, regulatory commissions in North Carolina and many other states have allowed the utility to recover the costs of an abandoned plant through amortization, while excluding the unamortized balance from rate base. In this way, a fair allocation of the losses is accomplished: the ratepayers are required to bear the losses resulting directly from the cancellation, while the shareholders must absorb the loss associated with the delay in receiving their compensation. This is the policy that the Commission adopted in Duke Power Company's case in November 1982; we have consistently adhered to it in the years since, and we see no valid reason to depart from it now.

The Commission does not agree with witness Fallon that the Company's receipt of three PDOs should factor into whether it should receive a return. The Commission notes that the Company chose to act without a PDO in 2010 and after the second quarter of 2013, over one third of the period of the project, thereby acting outside of the requirements of and protections offered by N.C. Gen. Stat. § 62-110.7. While N.C. Gen. Stat. § 62-110.7 is permissive and the Commission has found that the Company's Lee Nuclear incurred costs and activities were reasonable and prudent (except as discussed above in regard to the visitors' center and AFUDC) regardless of whether it received PDOs for the entire period, DEC's receiving Commission approval of some of its decisions to incur nuclear project development costs does not factor into the Commission's exercise of its discretion under N.C. Gen. Stat. § 62-110.7(d) as to whether the Company should get a return on the unamortized balance of the Lee Nuclear costs.

Additionally, the Commission rejects the contention by witness Fallon that having obtained a COL should merit shifting the entire burden of cost and risk to ratepayers. While the Commission agrees that the COL has value, that value will only be realized if the plant is built. Pursuant to the 2017 IRP, that possibility would occur only under very limited circumstances. Moreover, there is a cost to maintaining this option that DEC will likely be requesting ratepayers to bear in future rate cases.

Further, in Docket No. E-2, Sub 1035, DEP sought a deferral on its Harris COLA costs, but requested no return on the unamortized balance, citing State ex rel. Utils. Comm'n v. Thornburg, 325 N.C. 463, 385 S.E.2d 451 (1989) (holding that NCUC had authority to allow CP&L to recover capital investment in cancelled plants through 10-year amortization, with no return on the unamortized balance); Order Approving Stipulation and Deciding Non-Settled Issues, Docket No. E-7, Sub 828 (December 20, 2007) (treating GridSouth costs as an abandonment loss and allowing recovery of prudently-incurred costs over a 10-year amortization period, with no return on the unamortized balance); and Order Approving Partial Rate Increase, Docket No. E-7, Sub 358 (September 30, 1983) (allowing Duke Power to recover abandonment loss due to Cherokee Nuclear Units 1-3 cancellation over a 10-year amortization period, with no return on the unamortized balance). The Commission sees no reason to treat the Lee Nuclear Project differently, regardless of the difference in costs or achievement of a COL.

The Commission also notes that in its proposed order, for the first time in this proceeding, DEC argues that the Commission specifically made a distinction that it would treat the Lee Nuclear project development costs differently for purposes of ratemaking in its 2007 Order and that the General Assembly codified that distinction when it did not prohibit a return on the unamortized balance of prudently incurred costs during the amortization of a cancelled plant in N.C. Gen. Stat. § 62-110.7(d). In fact, DEC now argues that the principles of statutory construction that it weaves between N.C. Gen. Stat. § 62-110.7(c) and 110.7(d) support the Company's position that it should earn a return on the costs invested to develop the Lee Nuclear Project, even though it is cancelled. With respect to DEC's argument in these regards, the Commission simply disagrees. First, the Commission can unequivocally state that nothing in its 2007 Order spoke directly to or implied support for the Company to be able to earn a return on the unamortized balance. The Commission also notes that DEC's own witnesses testified that it was within the Commission's discretion whether or not to allow a return on the unamortized balance. Further, since the Lee Nuclear Plant is now cancelled, the term "…the potential nuclear plant…" that appears in N.C. Gen. Stat. § 62-110.7(c) is no longer applicable to the issue at hand, and N.C. Gen. Stat. § 62-110.7(d) is now controlling and there is no mention in N.C. Gen. Stat. § 62-110.7(d) regarding a return on the unamortized balance. In addition, although not applicable here, N.C. Gen. Stat. § 62-110.6(e), regarding rate recovery for construction costs of out-of-state electric generating facilities that are cancelled, directs the Commission to provide cost recovery as provided in N.C. Gen. Stat. § 62-110.1(f2) and (f3). N.C. Gen. Stat. § 62-110.1(f2) and (f3) include the provision that "...the Commission shall make any adjustment that may be required because costs of construction previously added to the utility's rate base pursuant to subsection (f1) of this section are removed from rate base and recovered in accordance with this subsection." (emphasis added) This analogous portion of the statute makes clear that costs associated with canceled plant are not part of rate base and the Commission determines to interpret N.C. Gen. Stat. § 62-100.7 which is silent as to the issue similarly. In summary, the Commission has carefully reviewed DEC's contentions that any prior Commission order or the ratemaking treatment prescribed in N.C. Gen. Stat. § 62-110.7(c) is supportive, applicable, or controlling with respect to allowing a return on the unamortized balance and disagrees.

Finally, although not discussed in the record, the Commission notes that during the entire 12-year period in which DEC incurred and funded the project development costs, it was allowed to accrue an AFUDC return. In fact, AFUDC comprises over forty percent of the total Lee Nuclear project development cost. The accrual of the AFUDC has already provided DEC, or its investors, a return on all non-AFUDC costs incurred during the past 12 years and that return will be recovered in cash from ratepayers over the next 12 years as the total allowed cost is amortized. The Commission concludes this consideration is supportive of its decision to require a fair allocation of costs for the cancelled plant between the Company and its ratepayers by denying a return on the unamortized balance during the 12-year amortization period.

D. Summary of Conclusions on Lee Nuclear

In summary, the Commission concludes in regard to the Lee Nuclear Project that the costs were reasonably and prudently incurred except the costs of the architectural and engineering design of a visitors' center and AFUDC after December 31, 2017. The Commission finds that it is reasonable and prudent for the Company to cancel the Lee Nuclear Project at this time. Finally, the Commission holds that the costs of the Lee Nuclear Project should be recovered through amortization over a period of 12 years, with no return on the unamortized balance.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 50-51

The evidence supporting these findings and conclusions is contained in the Company's verified Application and Form E-1, the direct testimony of Public Staff witnesses Robert Hinton and Michael Maness, the rebuttal testimony of Company witnesses Stephen De May and David Doss, and the entire record in this proceeding.

Background of the Nuclear Decommissioning Trust Fund

Every nuclear power plant owner in the United States is required under rules promulgated by the NRC to ensure that the nuclear plants it owns and operates are properly decommissioned when they reach the end of their useful lives. Monies to pay for decommissioning activities are collected from customers in rates and deposited in trust funds, where they are invested and earn returns.

DEC operates seven nuclear-powered units at three different power plants. Funds the Company has collected in rates from customers over the years, pursuant to specific authorizations contained in rate orders issued by this Commission, have been deposited in nuclear decommissioning trust funds (while each nuclear unit has its own decommissioning funds held in trust, for ease of reference, they are herein referred to collectively as the (NDTF)) pursuant to the NRC rules. Under those rules, as well as rules promulgated by the IRS, NDTF funds are to be used exclusively for nuclear decommissioning activities, which include license termination, dealing with spent fuel, and site restoration.

Through procedures described in greater detail below, every five years the Company engages a third-party consultant to perform a site-specific study and prepare a site-specific estimate of the decommissioning costs which will be necessary to decommission the units DEC owns and operates. Based upon that study, the Company files a report setting out those estimates (the Decommissioning Cost Study Report, or Cost Report). Every five years, based upon financial assumptions provided by additional third-party consultants, the Company models NDTF balances at the time of decommissioning and files a report in a prescribed format (the Decommissioning Cost and Funding Report, or Funding Report) detailing the total revenue requirement/decommissioning expense needed to fund its decommissioning obligations.

The Company last filed a Cost Report and Funding Report in 2014. Those Reports indicated that based upon projected decommissioning costs and projected NDTF balances (both projected decades into the future, inasmuch as decommissioning will not take place until decades into the future), the NDTF was adequately funded. Tr. Vol. 12, p. 48. Accordingly, the Company concluded that, at least as of that time, the Company need not collect in rates any cost with respect to nuclear decommissioning, and that additional contributions to the NDTF need not be collected from customers. The Company has not collected any NDTF contributions from customers since January 1, 2015.

Thereafter, with the joint support of the Company and the Public Staff, the Commission implemented a decrement rider as of July 1, 2015, reducing the Company's revenue requirements in order to reflect nuclear decommissioning costs at $0. In this rate case, based upon standard escalations of the 2014 Cost Report and 2014 Funding Report, the Company again concluded that the NDTF was adequately funded and determined that it need not collect any nuclear decommissioning expense as part of its cost of service.

In this docket, the Public Staff has taken the position that the NDTF is overfunded by $2.35 billion. The Public Staff asserts that in order to redress this supposed overfunding, the Company should be required to refund the excess by assigning to nuclear decommissioning "expense" a value of ($29 million) – that is, negative $29 million – per year. Acknowledging that the funds in the NDTF are untouchable for this purpose, in that they are to be used solely for decommissioning, the Public Staff developed a proposal by which the funds would be refunded to customers through the mechanism of a "loan" to be "repaid" after decommissioning is complete.

DEC contends the NDTF is not "overfunded." Further, as discussed below, under generally accepted accounting principles (GAAP), the Company believes it would have to write off the proposed "loan" inasmuch as it would not have a probable and acceptable path to repayment. DEC also argues that the approach recommended by the Public Staff is retroactive in nature, thus violating the prohibition against retroactive ratemaking in North Carolina. Finally, DEC submits prior orders of this Commission including prior agreements between the Public Staff and the Company appropriately provide for addressing surplus decommissioning funds – if any – at the conclusion of decommissioning.

Summary of Evidence Relating to NDTF

On July 25, 1988, the Commission opened Docket No. E-100, Sub 56 (Sub 56 Docket) to consider issues relating to decommissioning cost and funding for nuclear power plants owned and operated by the public utilities under its jurisdiction, namely Carolina Power & Light Company (now DEP), Duke Power Company (now DEC), and North Carolina Power (now Dominion North Carolina Power).[40]

On November 3, 1998, the Commission issued an Order in the Sub 56 Docket (Order Approving Guidelines (DEC – Maness Cross-Examination Ex. 1, Tab 1)), in which it adopted guidelines for the determination and reporting of nuclear decommissioning costs (the Guidelines). The Guidelines establish the five-year cycle of report filing described above, with respect to both the Cost Report, where the Company estimates decommissioning costs, and the Funding Report, detailing the total revenue requirement/decommissioning expense needed to fund the Company's decommissioning obligations. Further, as Public Staff witness Maness confirmed, the Public Staff is provided a 90-day period to issue discovery and investigate the cost and funding analysis the Company sets out in its Reports. Tr. Vol. 22, pp. 185-86. The Public Staff then has 90 days to prepare and file its own report. Id. In accordance with the Guidelines, the Public Staff has routinely reviewed the Company's decommissioning Cost Reports and decommissioning Funding Reports.

In the Company's last rate case, it proposed that nuclear decommissioning expense be $35 million. See 2013 DEC Rate Order, p. 110; DEC – Maness Cross Examination Ex. 1, Tab 3. The Public Staff, through witness Hinton, proposed an adjustment to reduce that expense to $14.6 million, which the Company accepted and the Commission ordered. Id. at 111. In the following year, the Company's five-year Cost Report/Funding Report cycle required it to file those Reports. As noted above, the Company concluded in connection with those filings that the NDTF was adequately funded and that a decrement rider to reduce nuclear decommissioning expense to $0 as of January 1, 2015 was warranted, which the Commission ultimately ordered. DEC – Maness Cross Examination Ex. 1, Tabs 2 and 4; Tr. Vol. 22, pp. 189-92.

As required by the Guidelines, the Public Staff investigated the 2014 Cost Report and the 2014 Funding Report, as well as the Company's suggestion that nuclear

[40] The Chairman ruled that the Commission would take judicial notice of the filings in the Sub 56 Docket in this proceeding. Tr. Vol. 22, p. 183.

decommissioning expense be reduced to $0 through a decrement rider. Tr. Vol. 22, p. 193. Its investigation was thorough, and the report that it prepared pursuant to the Guidelines was likewise thorough and well thought-out. Id. at 194. In that report (Public Staff Report; DEC – Maness Cross-Examination Ex. 2), the Public Staff noted that the NDTF fund balance would exceed estimated decommissioning costs at license termination[41] on a North Carolina retail jurisdictional basis by $2.5 billion. Id. at 11-12. The Report further indicated in its "Conclusions and Recommendations" section that the Public Staff had completed its investigation of the Cost Report and the Funding Report, had reviewed the Company's responses to data requests, and had no disagreement with the Company "regarding the calculation and implementation of the $0 expense/revenue requirements or any other aspect of its decommissioning cost and funding activity." Id. at 12. The Public Staff Report then concluded that apart from the implementation of the decrement rider, "the Public Staff has no recommendations for further action by the Commission in this matter." Id. (emphasis added).

In this rate case, the Company again determined that the nuclear decommissioning expense in its cost of service was $0. Tr. Vol. 12, p. 49. The Public Staff, however, asserted, through witness Hinton, that the NDTF was overfunded by $2.35 billion. Tr. Vol. 22, p. 252. The Public Staff proposed that these "excess" funds be returned to customers, and that this could be accomplished by reducing North Carolina retail expense by $29.1 million. Id. at 260.[42]

Under applicable NRC and IRS regulations, these funds could not be simply withdrawn from the NDTF, a fact recognized by Public Staff. Id. at 252. It indicated instead, through witness Maness, that if the Company "cannot remove such funds from the NDTF, its shareholders will be required to provide (i.e., loan) the funds for the expense reduction ...." Id. at 105 (emphasis added). Witness Maness added that this loan would be "on a temporary basis." Id. Company witness Doss testified, "if the Public Staff's recommended rate-making mechanism is approved, and if actual experience mirrors the projections on which the Public Staff's recommended refunds are based, the Company would not be entitled to collect on the loans to ratepayers until funds could be withdrawn from the NDTF upon the completion of nuclear decommissioning activities, which is currently expected to occur in approximately 50 years." Tr. Vol. 12, p. 60.

Discussion and Conclusions

The key factual predicate to the Public Staff's recommendation is that the NDTF is overfunded. The facts in this case indicate that it is premature to reach such a conclusion. The Public Staff's principal proponent of the notion that the NDTF is overfunded – witness Hinton – did not testify that this is the case in absolute terms. Rather, his testimony is hedged with qualifiers: "Assuming the projected decommissioning costs and earning returns ... are

[41] Measurement at license termination is the manner in which the Guidelines require the Funding Report to be filed. See DEC – Maness Cross-Examination Ex. 1, Tab 1, Attachment 1.

[42] Witness Hinton's direct testimony indicated that this figure was $19.4 million (Tr. Vol. 22, p. 252), but he discovered an error in his analysis and corrected the figure to $29.1 million Id. at 260.

accurate through when DEC's last nuclear unit is decommissioned, the NDTF is currently over-funded by $2.35 billion." Tr. Vol. 22, p. 252 (emphasis added). A number of qualifiers and the uncertainty regarding future events underlie witness Hinton's conclusion that the NDTF is currently overfunded. Id. However, witness De May testified that on an NC retail basis, the NDTF is actually underfunded as of the end of the test year:

> [T]he NDTF balance was $2.19 billion as of December 31, 2016. The estimated decommissioning cost (in 2016 dollars) as of December 31, 2016 was $2.46 billion. In other words, on a current dollars basis, the NDTF was approximately 89% funded as of December 31, 2016.

Tr. Vol. 4, pp. 79-80.

Witness De May further testified that the Company uses three methods to determine whether the funding levels in the NDTF are adequate such that the nuclear decommissioning portion of cost of service should be assigned a zero-dollar cost. One is the "current value" method, which is what is described above. Another is the "projected value" method, which is the basis of witness Hinton's conclusion. The projected value method measures, as its name suggests, the funds in the NDTF projected as of the end of decommissioning, still decades into the future, compared to projected costs, again decades into the future. In other words, the projected value method measures "the projected balance of the NDTF at the end of the decommissioning period, i.e., after all decommissioning activities are completed, and is in future dollars (ranging from 2058 through 2067)." Id. (emphasis added). Witness De May testified that this measure indicates whether the NDTF is adequately funded, but does not indicate that it is fully funded – for that, one cannot know "until the last dollar is spent on decommissioning." Id. at 568.

The third method witness De May described is the "probability of success" method. This method, witness De May explained, uses a probability of success ratio to evaluate the likelihood of having sufficient funds to fully decommission each nuclear unit. Id. at 80. This approach involves 5,000 Monte Carlo simulations of market returns and escalation factors between the time of analysis and the end of decommissioning and generates a percentage of scenarios for which funding is adequate to meet all future decommissioning obligations. Id. Witness De May testified that "[a]s of December 31, 2016, the nuclear unit probability of success ratios ranged from 77% to 85%, depending on the unit; conversely, the probability of not having sufficient funds to decommission the nuclear units ranged from 15% to 23%." Id. (emphasis in original). Although these percentages may support a determination that no additional funding from ratepayers is currently required to fund the NDTF, the Company submits that in no way should this be interpreted as supporting a view that the NDTF is "overfunded."

The Company based its determination that the NDTF funding levels were adequate and that, as a consequence, it would not request any nuclear decommissioning cost in its revenue requirements in this case, on the fact that the NDTF has experienced higher than expected returns recently and that the escalation rate assumption has remained modest. Id. at 82. There is, of course, no assurance that these conditions will extend into the future, and certainly no assurance that they will extend decades into the future. Uncertainty is further compounded by timing, as license extensions or unforeseen circumstances could accelerate or push out the plants' retirement dates. Insofar as escalation rates are concerned, witness De May testified that the model used to estimate funding requirements is highly sensitive to changes in the escalation rate assumption, and that an "increase in the forecasted escalation rate from 2.40% to 3.09%, a 0.69% increase, fully eliminates the projected NDTF overfunded balance at the end of the decommissioning period." Id. He noted that for the period 1913-2017, the average consumer price index (CPI-U) rate has been 3.24%. Accordingly, changing the escalation rate from the currently model rate of 2.4% just to the average CPI-U increase over the past hundred years means that the Public Staff's projected $2.35 billion overfunding disappears. Id. at 587.

He also testified regarding returns, "You probably hear this all the time in investment jargon, past returns are not an indication of future results." Tr. Vol. 5, p. 58. A 2015 Public Staff Report (DEC – Maness Cross-Examination Ex. 2), noted:

> The current healthy financial position of the … [NDTF] relative to estimated costs results largely from significantly higher than expected trust fund investment returns that have been experienced in recent years. The trust fund has not, however, always experienced such strong investment returns, and in fact, there have been many years of low or negative investment returns.

Id. at 13.[43]

Witness Hinton attempts to address concerns that the Public Staff's recommendation would lead to future underfunding by asserting that there are sufficient regulatory protections to avoid any significant under recovery in the NDTF. Tr. Vol. 22, p. 252. However, DEC contends that this statement ignores that some of those protections include restrictions preventing withdrawals from the NDTF. As witness De May indicated,

> [T]here is a reason it's illegal to take money out of the trust. It's because … [the NDTF is] not an investment account, it's not a savings account. It's there for the very good public policy of decommissioning nuclear power plants ….

Tr. Vol. 4, p. 588.

In light of all of the evidence presented, the Commission determines that it is premature to find and conclude that the NDTF is overfunded. While the funding model that is used to determine the annual nuclear decommissioning expense forecasts that under various assumptions, the NDTF may be overfunded by approximately $2.4 billion,

[43] For example, industry-wide from 2006 through 2008, the financial markets had a significant negative impact on trust fund balances. See NRC Office of Nuclear Regulation, 2009 Summary of Decommissioning Funding Status Reports for Nuclear Power Reactors (SECY-09-0146, October 6, 2009), p. 7, available online at: https://www.nrc.gov/docs/ML0925/ML092580041.pdf. The Commission takes judicial notice of this NRC report.

the evidence also indicates that on a current dollar basis it is only 89% funded. The Commission agrees with witness De May's concern that returning the projected excess funds to ratepayers now could lead to underfunding of the NDTF in the future. The record shows that the NDTF has experienced higher than expected returns recently, and the escalation rate used to forecast decommissioning costs has remained modest compared to historical rates of inflation, both of which have contributed to favorable results. Changes in assumptions for variables, including investment returns, escalation rates and decommissioning start or completion dates, will all impact future NDTF funding levels, as will deviation of future experience from current forecasts. In the judgment of the Commission, while the NDTF is currently adequately funded, it is premature to find and conclude that the NDTF is overfunded, and therefore, it would not be prudent to return funds to customers at this time, and perhaps for several years, even if it were legally permissible to do so.

Given the Commission's finding and conclusion in this regard, it is not necessary for the Commission to address the related issues between the parties regarding GAAP treatment, retroactive ratemaking and prior agreements.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 52-55

The evidence supporting these findings and conclusions is contained in the Company's verified Application and Form E-1, the testimony and exhibits of DEC witnesses Spanos, Doss, and Kopp, Public Staff witness McCullar, and the entire record in this proceeding.

Company witness Doss introduced Doss Exhibit 3, the revised depreciation study filed in this docket (Depreciation Study), as prepared by Gannett Fleming Valuation and Rate Consultants, LLC. Tr. Vol. 12, p. 56. As explained by witness Doss, the Depreciation Study included updates to estimates of final plant depreciation costs for steam, hydraulic, and other production plants, as well as updated forecasted generation plant retirement dates. Id. at 77. In addition, witness Doss introduced Doss Exhibit 4, the Decommissioning Cost Estimate Study (Decommissioning Study) prepared by Burns and McDonnell Engineering Company, Inc. (Burns & McDonnell), an external engineering firm. This report included estimates for final decommissioning costs at steam, hydraulic, and other production plants.

DEC witness Doss testified that the updated depreciation rates for various fossil and hydro plants reflect changes in the probable retirement dates to align with current licenses, industry standards, or operational plans due to aging technology, assumptions for future environmental regulations, or new planned generation. Tr. Vol. 12, pp. 51-52. In addition, the Depreciation Study incorporates generation assets that have been placed in service since the last study, as well as the W.S. Lee Combined Cycle Plant, once it goes into service. Id. at 52. Additionally, the rate for meters to be replaced under the Company's Advanced Metering Infrastructure (AMI) deployment was updated to allow recovery of the net book value over three years. Id. The Depreciation Study uses a 15-year average service life for the new AMI meters being deployed, increasing depreciation expense. Id. Finally, witness Doss also notes that there is a net decrease in the depreciation expense for distribution, transmission, and general plant assets, primarily driven by longer average service lives for assets such as overhead and underground conductors and services. Id.

Public Staff witness McCullar and CIGFUR III witness Phillips also made recommendations related to depreciation expense. Witness McCullar recommended several adjustments to the Company's proposed depreciation rates including adjustments to future terminal net salvage costs (also known as decommissioning and dismantlement costs), to other production plant interim net salvage percentages, and to remove inflation from terminal net salvage costs. Tr. Vol. 26, pp. 777-78, 783-85. Witness McCullar testified that based on December 31, 2016 investments, DEC was proposing an increase in its depreciation annual accrual of $81,480,296. Tr. Vol. 26 p. 773. Based on Public Staff witness McCullar's investigation, the Public Staff recommended an increase in DEC's depreciation annual accrual of $20,709,566 based on December 31, 2016, investments, a decrease of $60,770,730 from the amount proposed by the Company. Tr. Vol. 26, p. 775. The difference between the Company's and the Public Staff's proposed depreciation annual accrual results from four adjustments proposed by witness McCullar, and one recommended by Public Staff witness Maness, as discussed below. Finally, witness Phillips recommended that changes in the depreciation rates should net to a zero-dollar impact.

Estimated Terminal Net Salvage Costs – Contingency

Burns & McDonnell conducted the Decommissioning Study for DEC, which formed the basis for DEC's terminal net salvage cost estimates. In that study, a 20% contingency for future "unknowns" was included in DEC's estimate of future terminal net salvage costs. "Public Staff witness McCullar recommended that the 20% contingency for future "unknowns" included in DEC's estimate of future terminal net salvage costs be eliminated. Tr. Vol. 26, p 778. Witness McCullar explained that including a 20% contingency factor puts the risk of possible future unknowns on current ratepayers. Id. Witness McCullar pointed out that DEC has not identified actual future costs to be covered by the contingency, but estimates future terminal net salvage costs based on anticipated contractors' bids for dismantlement of equipment, addressing of environmental issues, and restoration of the site, and then adds 20% for unknown costs that DEC cannot specifically identify. Tr. Vol. 26, pp. 778-79. Public Staff witness McCullar testified that putting all the risk of "estimated future unknown unidentified costs" on current ratepayers was inappropriate and recommended a contingency of 0%. Tr. Vol. 26, p. 780. In response to witness McCullar's recommendation, DEC witness Kopp explained why a 20% contingency is appropriately included in DEC's Decommissioning Study. He explained that contingency protects customers by ensuring more accurate estimates of the costs of terminal net salvage to be incurred in the future. Tr. Vol. 10, p. 108. He stated that while these costs could not be specifically identified, it was reasonable to expect them to be incurred. Id. Witness Kopp explained that direct decommissioning costs were estimated based on performing known tasks under ideal conditions. Tr. Vol. 10, p. 109. However, Company witness Kopp admitted that Burns & McDonnell did not obtain any firm quotes for DEC facilities, but used unit pricing or its experience. Tr. Vol. 10, p. 137.

Further, according to witness Kopp, the contingency was added to recognize the likelihood of cost increases for unknown costs. Id. He pointed out uncertainties in work conditions, scope of work, the manner in which work would be performed, estimating quantities, weather, and unknown contamination, among other things. Tr. Vol. 10, pp. 109-10. DEC witness Kopp testified that inclusion of contingency costs was standard industry practice. Tr. Vol. 10, p. 110. He explained that a 20% contingency was appropriate at a site where power had been generated for years and where there was likely to be more environmental contamination, and thus was based on the level of risk of additional contamination. Tr. Vol. 10, pp. 111-12. Witness Kopp pointed out that there had been no on-site testing for hazardous materials or environmental contamination, no sampling of groundwater, no subsurface investigation, no asbestos inventories, and that the cost estimates included only a minimal level of environmental remediation. Tr. Vol. 10, pp. 111-12. Company witness Kopp contended that it would not be prudent to try to develop estimates that were more accurate or precise so that a smaller contingency would be reasonable, because of the high cost of conducting such a study and the limited time that the cost estimates could be considered reliable. Tr. Vol. 10, p. 113. Yet he argued that while these estimates were not precise enough to develop a more reasonable contingency, they were precise enough on which to base depreciation rates. Tr. Vol. 10, pp. 113-14. DEC witness Kopp noted that Burns and McDonnell had performed a decommissioning study for DEP in 2012, and that study's estimates for the decommissioning and demolition of Cape Fear, H.F. Lee, Sutton, Robinson, and Weatherspoon plants forecast costs 11% lower than actually incurred. Tr. Vol. 10, p. 114.

Accordingly, witness Kopp explained that a 20% contingency on these costs is both reasonable and warranted based on the risk level associated with the decommissioning projects. As the Company pointed out in its Response to Public Staff Data Request No. 17, the anticipated contractor's bid is based on performing known dismantlement tasks under ideal conditions. Id. at 116. (emphasis added) Witness Kopp contended that Public Staff witness McCullar had not taken into account that the direct costs were based on known tasks occurring under ideal conditions. Tr. Vol. 10, pp. 115-16. Witness Kopp also pointed out the minimal level of investigation Burns & McDonnell made into the existence and costs of potential environmental contamination and remediation, which he argued supported a 20% contingency. Tr. Vol. 10, p. 116. Regarding witness McCullar's contention that the Company should not recover a contingency for costs that cannot be identified at this time, witness Kopp agreed that specific future costs could not be identified, but noted that some typical costs that might be incurred or that have been incurred on similar projects were known. Tr. Vol. 10, pp. 117-18.

On cross examination, Company witness Kopp indicated that the Decommissioning Study did not take into account the impact of any planned changes to convert the Belews Creek, James E. Rogers (Cliffside), and Marshall plants to dual fuel capability as planned by the Company (Spanos/Kopp Cross Exhibit 1), which could increase or decrease the study's estimates. Tr. Vol. 10, pp. 127-29. Neither did the study take into account any changes in steel and aluminum prices that might occur due to imposition of tariffs. Tr. Vol. 10 pp. 133-34. Witness Kopp also stated that decommissioning and demolition was the most prudent option at the end of a plant's useful life, but acknowledged sale of a plant as another option. See Duke Energy's announcement of the sale of its retired Walter C. Beckjord coal-fired power plant, Spanos/Kopp Public Staff Cross Exhibit 3. Tr. Vol. 10, pp. 131-33.

In his testimony, DEC witness Kopp testified that, "[a]s engineering design for demolition progresses and some of these unknowns can be determined through subsurface investigations, asbestos sampling, and engineering specifications, the amount of contingency may be reduced; however, contingency would never be completely eliminated." Tr. Vol. 10, pp. 112-13. He also stated that the "Company performed no subsurface investigations, asbestos inventories, or groundwater sampling to identify and define remediation requirements during this planning phase." Tr. Vol. 10, p. 112. However, on cross-examination, witness Kopp admitted that the Company did perform asbestos inventories. Tr. Vol. 10, p. 136. But instead of relying on studies that had been performed, "Burns and McDonnell did not rely upon these historical studies ...." Tr. Vol. 10, p. 136.

DEC witness Kopp highlighted all the environmental testing that has yet to be done and all the uncertainties inherent in the study. While the Decommissioning Study was conducted based on data from 2016 and 2017, DEC has since announced plans to convert three of its plants to dual-fuel capability, changing some of the assumptions in the study. While it is impossible to anticipate all future costs, merely being able to identify possible future costs or costs incurred for other projects is not the most firm basis on which to calculate contingency. This causes some concern for the Commission.

The Commission takes note that the Company failed to take into account the possibility that scrap prices may increase or that the production plant may be repurposed, or sold. Further, DEC witness Kopp's claim that a contingency is needed to account for the unknown of asbestos is not fully supported by the record in this proceeding, since DEC has performed asbestos inventories and identified an asset retirement obligation for these legal asbestos abatement obligations. See Kopp/Spanos Public Staff Exhibit 4. Identifying these costs should reduce the unknown of asbestos and thus reduce any contingency.

Based on the above discussion and all of the evidence in the record, the Commission finds that the contingency proposed for net terminal salvage in this proceeding of 20% is improper and should be reduced. While the Commission appreciates the Public Staff's concern for keeping depreciation rates low, the potential for further environmental costs and remediation costs should not be given short shrift, especially in light of other environmental costs that are discussed elsewhere in this Order. However, the Commission acknowledges the arguments that the Public Staff has made, and in an attempt to strike a fair balance, the Commission finds that a 10% contingency factor is fair to all parties. The Commission further notes that in DEP's most recent rate case proceeding, Docket No. E-2, Sub 1142, the Commission approved a 10% contingency factor. The Commission is confident that a 10% contingency factor, while less than DEC's requested factor of 20%, should protect the Company from additional costs it will incur but cannot specify at the present date. The Commission also finds that a 10% contingency factor properly reflects the inclusion of items that should push unknown costs downward (i.e increase in scrap prices, etc.) thereby protecting the ratepayers as well. Based on the foregoing, the Commission concludes that including a contingency factor of 10% should be utilized by the Company.

Cost Escalated to the Date of Retirement

It is important to recover the service value of the Company's assets by determining the net salvage costs that will be incurred in the future. As DEC witness Spanos explained, using the straight-line method of depreciation, these costs are recovered ratably, or in equal amounts, each year over the life of the Company's plant. Tr. Vol. 10, p. 83. This approach is consistent with the Uniform System of Accounts, which specifies that the cost of removal is the actual amount paid at the time the transaction takes place. Id. at 84. As such, including the future cost of net salvage for plant accounts is consistent with established depreciation concepts. In developing decommissioning cost estimates, it is necessary to escalate those estimates to the time period in which the cost is expected to be incurred.

Public Staff witness McCullar testified that the Company took the estimated future terminal net salvage costs from the Decommissioning Study, which are in year 2016 dollars, and inflated them to the year of the assumed retirement of the production plant. She testified that DEC proposes to collect these inflated amounts in today's more valuable dollars from ratepayers. Tr. Vol. 26, pp. 780-81. Witness McCullar's Exhibit RMM-2 showed how for the Cliffside plant, the estimated terminal net salvage cost of $48,075,000 in year-2016 dollars was inflated to $105,945,645 in year-2048 dollars, assuming an annual inflation rate of 2.5% to 2048, the estimated year of retirement, increasing the estimated net salvage cost by a factor of 2.2. Tr. Vol. 26, p. 781. DEC proposes to begin collecting this $105,945,615 calculated using year-2048 dollars from current ratepayers, who would be paying in current dollars. Id. Public Staff McCullar contended that it would be unreasonable in this case to collect these inflated costs of removal in current dollars because it imposes too much risk on ratepayers due to the significant period of time over which the inflation is estimated. Tr. Vol. 26, p. 282.

Witness McCullar recommended that DEC should inflate the terminal net salvage costs to the year 2023, or the retirement date, whichever occurs first. Witness McCullar testified that she selected 2023 because it aligned with the time when the Company is expected to file its next rate case. Witness McCullar stated, "since depreciation rates approved in this proceeding are expected to go into effect in 2018, the year 2023 would be five years later, by which time depreciation rates would have been reviewed in a new base rate case." Tr. Vol. 26, p. 784. Witness McCullar noted that her recommendation reduces the risk on ratepayers associated with paying rates based on extended periods of estimated inflation, while protecting the Company from the risk that it would not be able to collect its net salvage costs. Tr. Vol. 26, p. 784.

Witness Spanos explained that many of the Company's plants will not be retired for many years. Tr. Vol. 10, p. 86. Witness Spanos highlighted the importance of "understanding the Company's expectations for these assets, as well as the estimates within the industry." Id. at 91. Accordingly, the net salvage costs must be escalated so that the correct amounts are allocated over the remaining lives of the plants. Tr. Vol. 10, p. 86. The approach used by the Company to escalate cost is widely supported by authoritative depreciation texts and industry practice. For example, witness Spanos pointed out that the NARUC Manual provides the following:

> Under presently accepted concepts, the amount of depreciation to be accrued over the life of an asset is its original cost less net salvage. Net salvage is the difference between gross salvage that will be realized when the asset is disposed of and the costs of retiring it.

Tr. Vol. 10, p. 88. (emphasis added).

In addition, Wolf and Fitch, another highly regarded authoritative depreciation text, provides further support for the position that inflation is appropriately a part of the future cost of net salvage. Wolf and Fitch also argue against a present value or current value concept. In his testimony, Witness Spanos provided the following passage from Wolf and Fitch:

> Some say that although the current consumers should pay for future costs, the future value of the payments, calculated at some reasonable interest rate, should equal the retirement cost. Studies show that the salvage is often "more negative" than forecasters had predicted.

Tr. Vol. 10, p. 89.

Finally, witness Spanos referenced Accounting for Public Utilities by Robert L. Hahne and Gregory E. Aliff to support the proposition that the Uniform System of Accounts and regulatory definition require net salvage to be estimated at a future price level. Id.

The testimony and evidence presented in this case demonstrates that authoritative texts and sound depreciation practices support escalating terminal net salvage costs to the date that the costs are expected to be incurred. Despite arguing against an approach in which the Company would recover costs over the life of the asset, witness McCullar concedes that some escalation is necessary. In fact, witness McCullar escalated terminal net salvage to the projected date for the Company's next base rate case in her calculations. Further, witness McCullar's escalation rate is entirely dependent on the timing of when the Company files its base rate case and lacks any nexus to the timing of the future retirement of the asset. The Commission notes that the record is void of any accounting literature support for witness McCullar's approach, nor would such an approach be appropriate.

The Commission cannot rely upon the scheduling of rate cases to remedy the flaws in witness McCullar's alternative proposal. Witness McCullar's approach is not supported by sound depreciation methods and would likely result in the under recovery of net salvage costs over the life of the asset. To that end, other state utility commissions have rejected witness McCullar's alternative approach as unsupported. For example, in a recent case before the Washington Utilities and Transportation Commission (WTC), witness McCullar advanced similar arguments against the escalation of terminal net salvage costs along with other recommendation related to depreciation.[44] In rejecting the recommendation, the WTC noted that Public Counsel and witness McCullar provided no response to the critique that witness McCullar's approaches were not supported by authoritative accounting literature.[45] The WTC found witness McCullar's net salvage proposal "[v]ague in its methodology, not supported by authoritative accounting literature, and supported by unwarranted assumptions."[46]

The fact is the vast majority of jurisdictions use a method for net salvage in which future net salvage is estimated at its future cost and recovered through straight-line depreciation (also known as the traditional method). Approximately 46 out of 50 jurisdictions recover future costs using the straight-line depreciation method. The use of this method is also consistent with the treatment of escalation in the most recent DEP rate case. As witness Spanos explained, depreciation should be done in a systematic and rational manner based on information known at the time and consistent with the Uniform System of Accounts. Id. at 165.

Considering all the evidence, the Commission finds and concludes that the escalation of terminal net salvage cost and the use of the straight-line method of depreciation in determining escalation as performed in the DEC Decommissioning Study is just and reasonable, appropriate for use in this case, and is adopted.

Other Production Plant Interim Net Salvage Percent Production Accounts

In this case, DEC witness Spanos testified that he recommended a future net salvage percent of negative 4% for other production accounts. Id. at 90. The estimated future net salvage is part of the annual depreciation accrual, which is credited to the reserve to cover the estimated future net salvage costs. As witness Spanos explained, he established an interim net salvage percent on an account basis and then performed the appropriate calculation in order to get the appropriate weighted interim net salvage, excluding account 343.1. Tr. Vol. 12, p. 143. The net salvage estimates were based on

[44] See Washington Utilities and Transportation Commission v. Puget Sound Energy, Final Order Rejecting Tariff Sheet; Approving and Adopting Settlement Stipulation; Resolving Contested Issues, & Authorizing and Requiring Compliance Filing, Washington Utilities & Transportation Commission, Docket UE-170033 (December 5, 2017) Puget Sound Order.

[45] Puget Sound Order, pp. 50-51.

[46] Id. at 60. The WTC noted further that witness McCullar's "comparison of net salvage accruals to net salvage expenditures PSE incurred during recent years would effectively recover net salvage as an operating expense, not a depreciation expense."

an analysis of historical cost of removal and salvage data, expectations with respect to future removal requirements, and markets for retired equipment and materials. See Doss Exhibit 3 IV-2; Tr. Vol. 12, p. 116. The interim net salvage component is approximately 32% of the utilized net salvage percent for other production plant. Id. at 90. Witness Spanos further testified that he noted that the Public Staff's recommended interim net salvage percentage had been included in the depreciation rate proposed for the Lee Combined Cycle Plant. Id. DEC witness Spanos contended that determining an interim net salvage percentage for other production plant should be based on historical data as well as informed judgment. Id. He stated that Accounts 343 and 344 included large amounts of gross salvage related to older combined cycle facilities not applicable to all assets in the account. Id. Company witness Spanos also stated that the high gross salvage numbers were related to the rotable parts of combined cycle facilities, consistent with DEP. Id.

Public Staff witness McCullar proposed a 0% net salvage value for accounts 342, 343, 344, 345, and 346. She testified that for some accounts, the annual accrual amount that would be accrued for estimated net salvage is several times the annual amount DEC actually incurs for net salvage. Tr. Vol. 26, p. 278. Witness McCullar indicated that the historical analysis has been a positive $12,891,310 per year for the last three years and a positive $8,649,160 per year for the last five years. Witness McCullar explained that these positive net salvage amounts indicated that DEC's booked gross salvage exceeded the Company's incurred costs of removal and thus, DEC did not need to collect interim removal costs for these accounts. As a result, witness McCullar took the position that DEC should utilized a 0% interim net salvage based on DEC's actual experience. Witness McCullar further testified that the 0% interim net salvage would not include the final decommissioning costs. The impact of the Public Staff's proposed adjustments to terminal net salvage contingency and escalation rates and interim net salvage results in a decrease in DEC's proposed depreciation rates as of December 31, 2016, of $13,382,159, as shown on p 14 of Exhibit RMM-1 on the line for Total Production. Tr. Vol. 26, p. 786.

In response, witness Spanos testified that in the case of other production plant, it is critical to understand all the components of the historical data. For example, in Accounts 343 and 344, there are large amounts of gross salvage and corresponding retirements that relate to the early installations of combined cycle facilities which are not applicable to all assets in the account. Tr. Vol. 10, p. 91. As witness Spanos described further, the high gross salvage amounts relate to the rotable parts of the combined cycle facilities, which are handled consistently with DEP's assets. Id. Under cross-examination by Public Staff, witness Spanos explained that Account 343 contains high salvage amounts in years 2014, 2015, and 2016, but using informed judgment, he understood those amounts to be related primarily to rotable parts and associated with combined cycle facilities. Using more than just statistical analysis is necessary to evaluate these production plants; informed judgment must also be relied upon as Witness Spanos did. In recommending the negative 4% interim net salvage percentage, witness Spanos took into account the Company's expectations for the assets as well as the estimates within the industry. Id.

The Public Staff presented evidence on cross-examination of DEC witnesses Kopp/Spanos regarding the Company's proposed positive net salvage percentages in Accounts 343 and 344 were related to rotable parts. Kopp/Spanos Public Staff Cross-Examination Exhibit 7 shows that DEC has established rotable parts in a separate account, Account 343.1. Further, Kopp/Spanos Public Staff Cross Exhibit 8 shows that the Public Staff did not propose any adjustment to the interim net salvage percentage for Account 343.1, Prime Movers Rotable. Additionally, under cross examination, witness Spanos admitted that Account 343.1, containing these rotable parts, was also excluded from the Company's interim net salvage proposal for Accounts 342, 343, 344, 345, and 346. Tr. Vol. 10, p. 143.

Based on the evidence discussed above and the entire record in this case, the Commission finds that the Public Staff's proposal to set an interim net salvage percentage of 0 for Accounts 342, 343, 344, 345, and 346 is reasonable. Historical data show that using a negative value, as was previously set, has resulted in DEC overcollecting its costs. It would be inequitable to charge customers for costs that the utility is unlikely to incur. As discussed previously, the Company has stated publicly that it plans to file multiple rate cases between 2019 and 2023, and therefore, this issue can be reexamined in the next base rate case.

Other Depreciation Recommendations

CIGFUR III witness Phillips recommended that any approved changes to depreciation rates should net to a zero-dollar impact on the level of depreciation expense included in rates. Tr. Vol. 10, p. 94. He further recommended that customers not be burdened at this time by the impact of shortening service lives of generating plants based upon assumptions about changing and evolving environmental regulations. Id.

As DEC witness Spanos correctly asserted, witness Phillips provided no support or justification for his net zero proposal, other than a desire that depreciation rates not increase. Tr. Vol. 10, p. 94. Witness Phillips offered no credible critique of the Company's filed Depreciation Study and provided no alternative analysis. The Depreciation Study demonstrates that current depreciation rates are insufficient and that adjustments are necessary for DEC to recover the full cost of its assets providing service to DEC's customers. Id. at 95.

Furthermore, witness Phillips incorrectly states that depreciation rates have changed due to changes to life spans as a result of environmental regulation. Witness Spanos highlighted that there are a variety of reasons that depreciation rates change over time as evidenced by the Depreciation Study filed in this case. The Depreciation Study includes all of DEC's assets, and changes in depreciation rates occur for many reasons, including updated service life and net salvage estimates, updated historical data, and additions to generating facilities. The Depreciation Study is based upon the available information regarding the Company's assets, and the depreciation rates, therefore, needs to be updated to reflect current circumstances. Tr. Vol. 10, p. 95.

For the foregoing reasons, CIGFUR III witness Phillips' blanket recommendation regarding depreciation rates lacks any conclusive support and is rejected.

Conclusion

In light of all of the evidence presented, the Commission finds and concludes that the depreciation rates proposed by DEC in this case, which are based on the revised Depreciation Study included as Doss Exhibit 3 and the Decommissioning Study included as Doss Exhibit 4, with the exception of the adjustments discussed above, are just and reasonable, fair to both the Company and its customers, and therefore, are approved.

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

The evidence in support of these findings of fact and conclusions is contained in the testimony and exhibits of Company witnesses De May, Fountain, and McManeus; Public Staff witnesses Boswell, Parcell, and Hinton; Tech Customers witnesses Strunk and Brown-Hruska, NCLM witness Coughlan; Justice Center et al. witness Howat; Kroger witness Higgins; CIGFUR III witness Phillips and the entire record in this proceeding.

The federal Tax Cuts and Jobs Act (the Tax Act) was signed into law on December 22, 2017. Among other provisions, the Tax Act reduced the federal corporate income tax rate from 35% to 21%, effective January 1, 2018.[47] It also repealed the manufacturing tax deduction and eliminated bonus depreciation. The Company filed its application for rate increase on August 25, 2017, many months before the enactment of the Tax Act and, therefore, the revenue requirement the Company requested was based on the pre-Tax Act tax laws.

On January 16, 2018, DEC witness McManeus filed her Second Supplemental Direct Testimony that only included limited discrete changes as a result of the Tax Act relating to the elimination of bonus depreciation and the manufacturing tax deduction. Her filing did not include an adjustment to income tax expense as a result of the decrease in the federal corporate income tax rate, nor did it include any proposal for the return of the protected and unprotected Federal EDIT to ratepayers.

In her direct testimony filed on January 23, 2018, Public Staff witness Boswell included an adjustment to income tax expense to reflect the decrease in the federal corporate income tax rate, as well as to remove the manufacturing tax deduction that was also included in the Tax Act. She stated that at that time, the Public Staff was waiting for information from the Company regarding Federal EDIT and reserved the right to supplement her filing to include the Public Staff's proposal for flow back of Federal EDIT.

[47] In response to the enactment of the Tax Act, on January 3, 2018, the Commission opened a rulemaking docket (Docket No. M-100, Sub 148, i.e. the Tax Docket) for the purpose of determining how the Commission should proceed. In the Order establishing the Tax Docket, the Commission placed all public utilities on notice that the federal corporate income tax expense component of all existing rates and charges, effective January 1, 2018, would be billed and collected on a provisional rate basis.

In rebuttal testimony filed on February 6, 2018, DEC proposed an immediate reduction in the Company's revenue requirement, within the context of this proceeding, to account for the reduction in the federal corporate income tax rate but offered no proposal to return Federal EDIT to ratepayers. Company witness Fountain testified that the passage of the Tax Act "provides the Commission with a unique tool to smooth out customer rate adjustments during a multi-year transition period." Tr. Vol. 6, p. 212. He stated that this could be accomplished by offsetting items such as storm response costs, ongoing coal ash basin closure compliance costs or other environmental compliance costs, or accelerating the depreciation of certain assets, such as the existing AMR meters or coal plants. Tr. Vol. 6, p. 213.

In her rebuttal testimony, witness McManeus testified that the Company opposed witness Boswell's adjustment to reduce income tax expense. Tr. Vol. 6, p 323. Witness McManeus testified that the Company had identified the amount of reduction in annual revenue requirement related to reduced income tax expense and translated the amount into a decrement rate per kWh. Witness McManeus stated that the Company proposed to apply the decrement to North Carolina retail service beginning January 1, 2018, and defer the resulting amount into a regulatory liability, continuing the deferral until new rates are established in this rate case that reflect the benefits of the lower tax expense. Tr. Vol. 6, p. 331.

In supplemental testimony filed on February 20, 2018, witness Boswell presented the Public Staff's proposal regarding the flowback of Federal EDIT. Witness Boswell included three adjustments based on the information provided by the Company. First, she recommended the return of protected Federal EDIT based upon the Company's calculation of the net remaining life of the timing differences, as required under the Internal Revenue Code. For the unprotected Federal EDIT, witness Boswell recommended removing the Federal EDIT regulatory liability associated with the unprotected differences from rate base, and placing it in a rider to be refunded to ratepayers over two years on a levelized basis, with carrying costs. Witness Boswell stated that immediate removal of unprotected Federal EDIT from rate base increases the Company's rate base and mitigates regulatory lag that might occur from refunds of unprotected Federal EDIT not contemporaneously reflected in rate base. Further, she maintained that refunding the unprotected Federal EDIT over two years allows the Company to properly plan for any future credit needs. Tr. Vol. 26, pp. 618-19. Ultimately, during the hearing, the Public Staff modified its proposal to adjust the flowback period from two years to five years. Boswell Second Supplemental Testimony, filed March 19, 2018, Tr. Vol. 26, pp. 637-38. The modified proposal is referred to herein as the Public Staff Proposal.

In response to the Public Staff's original 2-year EDIT flowback proposal, the Company Proposal was made initially in Supplemental Comments, filed March 1, 2018, in Docket No. M-100, Sub 148, a docket that the Commission established on January 3, 2018, in order to gather comments from the utilities it regulates along with the Public Staff and other interested parties, to decide how to implement the Tax Act (Tax Docket). By letter filed the next day, the Public Staff objected to the Company Proposal being made in the Tax Docket, in light of the fact that the Company's general rate case was then open and had not yet gone to hearing. Accordingly, the Company then made its proposal in this Docket on the opening day of the expert witness evidentiary hearings, and the Commission took judicial notice of all filings in the Tax Docket. Tr. Vol. 5, p. 14.

On the first day of the evidentiary hearing, the Company presented its proposal to address the Tax Act. The Company Proposal was presented in this proceeding by witness De May. Tr. Vol. 4, pp. 423-24; Tr. Vol. 5, pp. 67-79; De May Rebuttal Ex. 5. The Company Proposal has three basic component parts, and the first two components reduce the Company's revenue requirement.

First, the Company Proposal implements an immediate reduction of approximately $211.5 million to the Company's revenue requirement to reflect collection of federal corporate income tax at the 21% rate instead of the 35% rate. Revised McManeus Stipulation Exhibit 1 – Updated for Post-Hearing Issues, Line 29; Revised McManeus Workpapers – Updated for Post-Hearing Issues, Schedule 1-1, Line 1.

Second, the Company Proposal implements Federal EDIT flowback to customers, with the flowback timeframes varying based on the particular Federal EDIT bucket at issue:

- For protected Federal EDIT, the Company Proposal applies the Tax Act-prescribed IRS normalization rules, resulting in a reduction in revenue requirements of approximately $34.4 million annually or per year. Revised McManeus Stipulation Ex. 1 – Updated for Post-Hearing Issues, Line 30; Revised McManeus Workpapers – Updated for Post-Hearing Issues, Schedule 1-1, Line 2.
- For unprotected Federal EDIT related to property, plant and equipment, the Proposal also applies the normalization rules, although, as all of the parties agree, application of those rules is not required by the Internal Revenue Code. The only modification, that results in a faster flowback, is that while the Company's analysis indicates that the average life of the flowback in the absence of the Tax Act would have been 25 years, the Proposal implements that flowback over 20 years. Tr. Vol. 5, pp. 78, 105. DEC maintained that this was done "for the sake of simplicity" (id. at 105.), and results in a reduction in revenue requirements of approximately $36.7 million annually or per year. Revised McManeus Stipulation Ex. 1 – Updated for Post-Hearing Issues, Line 33; Revised McManeus Workpapers – Updated for Post-Hearing Issues, Schedule 1-1, Line 3.
- For unprotected Federal EDIT not related to property, plant and equipment, the Proposal implements flow back through a five-year decrement rider, with the five-year timeframe being used again "for the sake of simplicity." Tr. Vol. 5, p. 105. The reduction in revenue is approximately $39.6 million per year during the five years the rider is in effect. Revised McManeus Workpapers – Updated for Post-Hearing Issues, Schedule 1-1, Line 7. Because these unprotected Federal EDIT are being flowed back to customers through a rider, that includes a return component, base rates must be adjusted correspondingly (as an increase) in the

amount of $15.1 million. Revised McManeus Workpapers – Updated for Post-Hearing Issues, Schedule 1-1, Line 5.

Accordingly, the reduction in revenue requirements effected by these two components of the Company Proposal equals $307.1 million annually or per year. Revised McManeus Workpapers – Updated for Post-Hearing Issues, Schedule 1-1, Lines 1-3, 5 and 7.

The third component of the Company Proposal mitigates, but does not eliminate, the negative cash flow impact of these reductions by increasing annual revenue requirements by $200 million. The Company Proposal (De May Rebuttal Ex. 5) did not originally identify specific means through which this could be accomplished, but did provide examples of accelerated regulatory asset amortization, and also suggested the alternative of collecting certain expenses (for example, the coal ash basin closure cost "run rate") on an accelerated basis.[48] As witness De May testified, in concept this component of the Company Proposal aims "to preserve the cash flow and credit quality, and we can skin that cat a few ways." Tr. Vol. 5, p. 87.

Combined, therefore, the three component parts of the Company Proposal net to a reduction in the Company's annual revenue requirement of almost $107 million. Revised McManeus Workpapers – Updated for Post-Hearing Issues, Schedule 1-1. The Company Proposal implements an immediate reduction in rates to reflect the 21% Federal corporate income tax rate, but also, as witness De May testified, mitigates the impacts and "preserve[s] … [the Company's] credit quality ... to something that resembles pre-tax reform." Tr. Vol. 5, p. 82.

On cross-examination, Company witnesses Fountain and McManeus were questioned about the Company's income tax proposal. Witness McManeus acknowledged that ratepayers advanced the funds that constitute the Federal EDIT at issue. Tr. Vol. 6, p. 399. She also conceded that tax normalization laws do not dictate when unprotected PP&E Federal EDIT should be returned to ratepayers (unlike protected Federal EDIT). Tr. Vol. 6, p. 399. Witness McManeus further admitted that because unprotected Federal EDIT is not subject to tax normalization rules, the Commission has discretion as to the time period over which the funds will be returned to ratepayers. Tr. Vol. 8, p. 224. She agreed that due to the reduction in the tax rate, the Federal EDIT is no longer needed to cover the Company's taxes. Tr. Vol. 8, p. 224. Witness McManeus acknowledged that the $200 million in accelerated expenses would be included in the Company's revenue requirement. Tr. Vol. 8, p. 226. When asked to identify the specific assets and other items that the Company would include in the proposed $200 million acceleration, she could not identify anything specific, referring to the general options set forth in the proposal. Tr. Vol. 8, p. 230. Witness Fountain conceded that he could understand the positon of some customers who would like to have the benefits of the

[48] Kathy Sparrow, one of the public witnesses in the public witness hearing held in Charlotte on January 30, 2018, also suggested that tax reform gains and coal ash costs could offset against each other. Tr. Vol. 3, p. 95.

federal tax reform all flowed back immediately, but testified that the Company's proposal is balanced. Tr. Vol. 7, p. 94.

In response to Commission questions about the Company's income tax proposal, witness McManeus testified that the $200 million figure was provided by witness De May as an appropriate number to accomplish the objectives that he had in mind. The Company did not provide any specific numbers that comprise the $200 million. Tr. Vol. 9, p. 38. Witness Fountain could not identify any specific regulatory assets the Commission could select for accelerated amortization. Tr. Vol. 9, p. 90. Witness Fountain acknowledged that the Company is merely trying to achieve a particular financial metric for its cash flow. Tr. Vol. 9, p. 90.

On March 19, 2018, Public Staff witness Boswell filed her Second Supplemental Testimony. In addition to explaining the current differences between the Company's and the Public Staff's revenue requirement proposals and to refine the outside services adjustment, she addressed DEC's income tax proposal. She explained that while the Company has incorporated the known and measurable reduction in income tax expense associated with the decrease in the federal corporate income tax rate, the Company appears to have made the refunding of known and measurable tax dollars owed to ratepayers contingent upon increasing annual expenses by $200 million per year for an unknown number of years through the acceleration of depreciation for as yet unknown assets or through accelerating the amortization of costs associated with coal ash basin closures. Tr. Vol. 26, p. 634. She also noted that the Company has calculated the known and measurable refund of protected Federal EDIT based upon tax normalization rules. However, regarding unprotected Federal EDIT, she stated that the Company has proposed an amortization of approximately 82% of its unprotected Federal EDIT over 20 years, with the remaining 18% amortized over five years.

Thus, the Company's and the Public Staff's proposals differ as to: (1) the rate at which unprotected Federal EDIT should be flowed back to ratepayers; and (2) whether it is appropriate to increase the Company's revenue requirement by $200 million to accelerate depreciation of unknown and unspecified assets or legacy meters, or accelerated amortization of coal ash costs. Tr. Vol. 26, pp. 634-35. Witness Boswell noted that the Company does not dispute that the Commission has the discretion to flow back all of the unprotected Federal EDIT over any time period it finds appropriate. Tr. Vol. 26, p. 636. Company witness De May testified extensively regarding the impact implementation of the Tax Act could have on the Company's credit quality and the importance of maintaining the Company's current, high credit rating. Witness De May explained that as a result of the Tax Act, Duke Energy Corporation, the parent Company of DEC, was placed by Moody's on negative credit outlook. Tr. Vol. 4, p. 541. He explained that a negative outlook is different from a ratings downgrade. Witness De May stated that it is "like a yellow light, a warning" (id.), signaling to the investment community that a ratings downgrade could materialize in the next 12 to 18 months. Id. The January 2018 Moody's Report states that the Tax Act is "credit negative" for the utilities sector because of its impact upon cash flow, and that among the companies most negatively impacted is Duke Energy Corporation, the parent company of DEC.

January 2018 Moody's Report, pp. 1, 3. The Report specifically notes that the parent corporation's "consolidated cash flow credit metrics are currently weakly positioned and likely to be incrementally pressured by tax reform." Id. at 5.

While Moody's has not put DEC on negative credit outlook, as witness De May explained, "the risk to Duke Carolinas is not zero just because it was not named in the initial report." Tr. Vol. 4, p. 542. Witness De May testified that while DEC currently maintains "a very strong balance sheet," the Tax Act is biased toward the health of corporations, and because utilities are structured different than most corporations, the Tax Act impacts utilities negatively. Tr. Vol. 5, p. 82. As Moody's notes, "most utilities will attempt to manage any negative financial implications of tax reform through regulatory channels … [and that] actions taken by utilities will be incorporated into our credit analysis on a prospective basis." Moody's January 2018 Report, p. 3.

Moreover, witness De May elaborated, during cross-examination by counsel for CIGFUR III, on the negative impact of weakening the Company's balance sheet: "Duke Energy Carolinas' customers benefit from a strong utility company … [and] a weakening of the balance sheet is not in the customer's interest, and it does not support the Company's capital plan …." Tr. Vol. 4, pp. 436-37. He testified further, "[u]ltimately, adverse cash flow impacts also have an adverse impact upon customer rates – DE Carolinas' customers benefit through lower electricity rates when the Company has lower financing costs, greater access to capital, and more timely cash recovery of its investments." Id. at 88-89.

The Company has proposed a 20-year flowback of unprotected but property-related EDIT. The Public Staff has criticized this aspect of the Company Proposal on several grounds. First, Public Staff witness Boswell asserted that the Company has "artificially" created the class of unprotected property-related EDIT. Tr. Vol. 26, p. 636. Witness De May explained that the 20-year period in the Company Proposal is tied directly to the underlying assets that created the deferred tax balances that became Federal EDIT when the Tax Act dropped the corporate income tax rate to 21%. As witness De May testified:

> I would say that from a theory perspective, those excess deferred taxes actually have a life. When I described to you what happened in a single asset where we collect from customers before we pay the government and then we're paying the government, but not collecting from customers, that is something that is dealt with through normalization. But there's a life to that; there's a life cycle to that, and protected and unprotected property related deferred taxes are no different except for the fact that they come from two places in the Internal Revenue Code and the statute protects one and it doesn't the other.

Tr. Vol. 5, p. 78. Witness De May testified further in response to questions from Commissioner Brown-Bland that he trusted "firmly in the theory behind the flowback of excess deferred taxes over the life of the underlying assets" (id. at 102-03.), that the normalization concept underlying the 20-year flowback proposal was discussed at length in the GAO Report, and that "normalization exists for a reason …." Id. at 103. Witness De May testified that normalization balances the customer and Company interests; it protects the Company's cash flow and also protects the customer against rate volatility, because the deferred balance acts as an offset to rate base, and, therefore, a reduction in rates. Id. at 104.

Also, as both the GAO Report and witness De May noted, deferred taxes represent an interest-free loan from the government that the Company then used, at no cost to customers, to invest in its business. Tr. Vol. 5, pp. 72-73. Witness De May explained that by making these investments, customers saved capital costs by the Company using an interest-free loan from the government rather than investor-supplied capital. However, witness De May testified that because these funds have been invested there is not a readily available reserve pool from which the cash needed to flow back the EDIT can be drawn and the Company would have to enter into financings to flow back EDIT in two years as originally proposed by the Public Staff. Id. at 79. He explained that it helps avoid volatility in customer rates. Id. at 80. Witness De May stated that, "[i]f we flowback these excess deferred taxes instantly or over a two-year period, you would see a dramatic reduction in customer rates followed by a snapping back of rates" and then a faster growth in rates due to the higher rate base. Id.

The Public Staff also raised generational equity concerns in advocating for a shorter flowback time period. EDIT funds, it indicated, "rightfully belong to the ratepayers and should be returned to them as soon as reasonably possible." Tr. Vol. 26, p. 637. Witness De May responded, ". . . we have to think about how that balance got created." Tr. Vol. 5, p. 73. Witness De May noted that it was created because of tax deferral, and the funds so generated then were invested in the business. Id. The Company argued that normalization, or the gradual return of EDIT over the life of the capital asset being depreciated, actually fosters generational equity by spreading the depreciation benefit over that time period.

The Company asserted that the Public Staff's proposed 5-year flowback would negatively impact its credit metrics. Tr. Vol. 5, p. 86. DEC maintained that, in fact, Hinton Cross Examination Exhibit 1 indicates that the relevant FFO/Debt ratios for the Public Staff Proposal over the Company's five-year planning horizon would fall below the 25% threshold, which the most recent Moody's report on DEC warned could result in a possible downgrade. See Moody's October 2017 Report, p. 2.

Finally, the Public Staff criticized the Company Proposal on the basis that in the last major overhaul of the Tax Code in 1986, the Company proposed and the Commission accepted a 5-year flowback of unprotected EDIT. See Order Allowing Rates to Become Effective (Stipulated 1987 Order), dated December 4, 1987, filed in Docket Nos. M-100, Sub 113 and E-7, Sub 415.

The Company, however, noted some differences between the 1986 tax law and today's Tax Act. First, DEC asserted that the total amount of the North Carolina retail portion of unprotected Federal EDIT is approximately $953 million, and in 1987, the North Carolina retail portion of unprotected Federal EDIT was approximately $28 million. See

Application by Duke Power Company for Authority to Decrease Electric Rates and Charges (Stipulated 1987 Application), dated November 13, 1987, filed in Docket No. E-7, Sub 415. Also, as witness De May testified, the magnitude of the reduction in tax rates was smaller in 1986 – the reduction was from 46% to 34%, a 26% decrease, while today the reduction was from 35% to 21%, a 40% decrease. Tr. Vol. 4, p. 446. Finally, DEC argued that the general business environment was different as well. Witness De May testified that in 1986, the Company experienced 5-6% customer growth and today it is half of a percent. Id. at 448. See De May – Public Staff Cross-Examination Ex. 21, Slide 24. Witness De May also stated that the Company is "experiencing environmental challenges unlike anything we had in 1986." Tr. Vol. 4, p. 448.

According to DEC, another credit supportive measure is the third component of its Proposal, which mitigates the negative cash flow impact of Federal EDIT flowback by increasing revenue requirements by $200 million annually. The Public Staff indicated that it is "adamantly opposed" to this part of the Company Proposal. Tr. Vol. 26, p. 639. The Public Staff argued that adoption of this part of the proposal would "virtually" wipe out the "entire" benefit to customers. Id. The Company, however, has noted that customers will benefit under the Company Proposal by $107 million per year. Revised McManeus Workpapers – Updated for Post-Hearing Issues, Schedule 1-1. This component of the Company Proposal provides for early collection of regulatory assets – that is, from the customer perspective, liabilities otherwise owed to DEC by customers. Tr. Vol. 4, p. 445. Witness De May explained that extinguishing these liabilities has a beneficial effect on the Company's cash flows, but also means that customers will pay less in the future. Id. DEC maintained that accelerated payment also reduces the carrying cost of those regulatory assets, again lowering customer charges. Moreover, the Company noted that the Moody's January 2018 Report forecasted this exact type of regulatory outcome, which Moody's predicts will be credit supportive as utilities work through regulatory channels to manage the negative financial implications of tax reform, stating: "For example, to offset a decline in cash flow, utilities could propose to regulators additional investments that benefit customers or accelerate recovery of regulatory assets." Moody's January 2018 Report, p. 3.

The AGO asserted in its post-hearing brief that as a result of recent reductions in the federal corporate income tax, DEC's costs are much lower going forward and it has accrued a large sum in federal deferred taxes that it no longer needs. The AGO argued that these cost reductions should be flowed through to ratepayers promptly. The AGO recommended that the Commission reject DEC's problematic proposals and approve utility rates that promptly flow through the benefits for customers. The AGO stated that it concurs with the testimony given on behalf of DEC's ratepayers, who advocate a prompt reduction in the Company's revenue requirement to account for the cost of service impact.

The AGO maintained that the extra $200 million increment sought by DEC should be rejected, because by deviating from the statutorily mandated ratemaking formula, DEC would establish rates that are inflated by design. The AGO asserted that fixing rates that are intended to over-collect revenues is contrary to the ratemaking formula in N.C. Gen. Stat. § 62-133(b) and (c), and violates key ratemaking principles. The AGO stated that the Commission's responsibility is to "fix such rates as shall be fair both to the public utilities and to the consumer." N.C. Gen. Stat. § 62-133(a). The AGO further stated that the statutory intent is that the Commission "fix rates as low as may be reasonably consistent" with Due Process constitutional considerations.[49] The AGO asserted that the burden of proof is on the utility to show that its proposed changes in rates are just and reasonable according to N.C. Gen. Stat. § 62-75; 62-134(c) and that DEC cannot meet that burden.

The AGO noted that Commission precedent and North Carolina case law support the prompt flow-through of tax reform benefits to utility ratepayers. The AGO noted that when Congress passed the Tax Reform Act of 1986, the Commission found that the significant reduction to the tax rate would "have an immediate and favorable impact on the cost of providing ... public utility services to consumers in North Carolina," and concluded that "[i]t is incumbent upon this Commission to take the appropriate action as required so as to preserve and flow through to ratepayers, as a reduction to public utility rates, any and all cost savings realized in this regard which would otherwise accrue solely to the benefit of the stockholders." Order Initiating Investigation In the Matter of the Tax Reform Act of 1986, issued October 22, 1986 in Docket No. M-100, Sub 113, at 1. The AGO noted that, affirming the Commission's final decision in that proceeding, the North Carolina Supreme Court observed that the purpose of the Commission's proceeding in 1986 was to "take the effect of the reduction in tax rates and flow it through to the ratepayers." State ex rel. Utils. Comm'n v. Nantahala, 326 N.C. at 197, 388 S.E.2d at 122.

The AGO stated that, similarly, when the North Carolina legislature adopted tax reform in 2013, it intended for the benefits of reduced state income taxes to be flowed through to ratepayers as the tax changes occurred. See In the Matter of Implementation of House Bill 998 – An Act to Simplify the North Carolina Tax Structure and to Reduce Individual and Business Tax Rates in Docket No. M-100, Sub 138.

The AGO maintained that furthermore, although DEC has claimed that customers may be harmed by the reduction to its cash flow prompted by a reduction in rates, the evidence in support of that hypothetical position was not substantiated. The AGO stated that the Tech Customers witnesses Brown-Hruska and Strunk reviewed claims by DEC witness De May that the Company's funds from operations to debt (FFO/Debt) ratios would drop to the point that a downgrade would likely occur. The AGO stated that based on their review of the projected FFO/Debt ratios proffered by witness De May and the most recent credit assessment from Standard & Poors, they concluded that DEC's credit metrics would not be jeopardized by the elimination of the additional $200 million in cash flow. Tr. Vol. 26, p. 514.

The AGO noted that, rather, the Company's projections demonstrate that the Company is on track to maintain and even to exceed, after implementation of the Tax Act, FFO/Debt ratios in the range of 24 to 26 percent, which is the base case assumption

[49] State ex rel. Utils. Comm'n v. Duke Power Co., 285 N.C. 377, 388, 206 S.E.2d 269, 276 (1974) (Duke Power).

relied upon by S&P before the Tax Act became law. Consequently, the AGO recommended that the Commission reject DEC's request for a $200 million annual increase in its revenue requirement.

The AGO noted that another impact of the federal income tax rate reduction is that it prompts a large reduction in the amount of accumulated deferred income taxes that DEC has accrued. The AGO stated that DEC acknowledges that customers should benefit from the excess accumulation. The AGO stated that, nonetheless, DEC proposes to spread out the return of most of the excess over many years, so that its rates are not reduced as much as they would be if the excess is returned promptly.

The AGO stated that it supports a return of the excess deferred taxes as soon as possible, but in no event longer than the initial recommendation of the Public Staff to return the excess deferred income taxes over 2 years because ratepayers will benefit immediately from the use of the amounts they are owed. The AGO argued that DEC has not supported its claim that any harm will fall to customers by the prompt return of the funds, and it is time for DEC to stop relying on excess revenues or a loan from its customers to maintain the overly flush cash flow that was provided under former tax deferral policies. The AGO asserted that the alternative of not returning dollars to consumers who struggle to pay their bills, or to consumers who would use their money for different purposes if given the opportunity, results in an undue burden on ratepayers and communities in North Carolina.

CIGFUR III stated in its post-hearing brief that the Commission should reject DEC’s proposal to prolong the return of unprotected PP&E EDIT to ratepayers over a period of 20 years and should implement the Public Staff’s proposal to return all unprotected EDIT over a five-year period.

CIGFUR III stated that in the early years of a given capital asset, the utility collects more in tax expense from ratepayers than it pays out to the IRS due to the difference in accelerated depreciation for tax purposes and straight-line depreciation for ratemaking purposes; that situation reverses once the ratemaking depreciation expense begins to exceed the tax depreciation. CIGFUR III noted that assuming that tax rates stay constant, over the life of a capital asset, the total tax expense paid by the ratepayers to the utility should match the tax expense the utility pays in federal taxes. CIGFUR III maintained that as a result of the differences in depreciation timing and because tax funds are ratepayer supplied, in the early years of a given capital asset ratepayers provide the utility an interest-free loan, reflected as a credit to the utility’s ADIT liability account. CIGFUR III noted that due to the Tax Act, DEC’s future tax liabilities will not be as high as anticipated when DEC filed its general rate case in August 2017, and the amount by which DEC’s current ADIT balances exceed their future income tax liability because of the Tax Act are the EDIT at issue.

CIGFUR III stated that while certain EDIT have been designated by the IRS code as “protected” and are required to be normalized over the remaining life of the asset, the Commission has wide discretion in the timing and duration of the return of “unprotected”

EDIT. CIGFUR III recommended that the Commission conclude that unprotected EDIT should be promptly flowed back to ratepayers; however, the Company proposes to delay returning what it designates as unprotected PP&E EDIT, although it concedes that this category of EDIT is not subject to IRS tax normalization rules. CIGFUR III stated that it opposes delayed return of unprotected EDIT and supports the Public Staff's recommendation that the unprotected EDIT be returned to ratepayers over 5 years.

CIGFUR III argued that the tax normalization rules are very clear and either EDIT is protected, or it is not. CIGFUR III asserted that the EDIT that the Company designates as "PP&E-related" is still clearly unprotected; a fact conceded by the Company. CIGFUR III stated that the Company's assertion that it should only return this PP&E-related unprotected EDIT over the same period of time it would have paid the funds to the IRS had the tax law not been passed is not supportable by any logical accounting or ratemaking principle, and should not dictate this Commission's decision as to what is a reasonable amount of time within which to return these funds to ratepayers. CIGFUR III asserted that these funds rightfully belong to the ratepayers and should be returned to them as soon as reasonably possible.

CIGFUR III maintained that while DEC stated that the delayed refund of unprotected EDIT is needed to protect its FFO/Debt ratio and thus its credit metrics, it has failed to offer compelling evidence in support of this justification. CIGFUR III asserted that to the contrary, Public Staff witness Hinton testified and concluded that, "it is unlikely that spreading the EDIT over five years will result in a debt rating downgrade and it is reasonable and fair to Duke's ratepayers and the Company." Tr. Vol. 22, p 277. As such, CIGFUR III urged the Commission to adopt the Public Staff's proposal to return all unprotected EDIT over 5 years.

CIGFUR III also recommended that the Commission reject DEC's proposal to "smooth out rate volatility" by slowing the flowback of benefits to ratepayers by accelerating the depreciation of ill-defined assets amounting to $200 million per year. CIGFUR III noted that DEC has requested this $200 million annual increase to its revenue requirements to collect expenses related to AMR meters, coal-fired plants, or coal ash clean up on an accelerated basis; specifically, the Company contended that its requested $200 million annual increase in its revenue requirement is required to mitigate the negative cash flow impact of the revenue requirement reductions resulting from the Tax Act and protects the Company's pre-Tax Act credit quality. CIGFUR III contended that, however, to the contrary, witnesses Strunk and Brown-Hruska, testifying on behalf of the Tech Customers, contended that:

> [T]he projected FFO/Debt ratios, adjusted so as to eliminate the request for an additional $200 million in cash flow, do not jeopardize the Company's credit metrics. Rather, the Company's projections demonstrate that the Company is on track to maintain and even to exceed – after implementation of the Tax Act – FFO/Debt ratios in the range of 24 to 26 percent, which is the base case assumption relied upon by S&P before the Tax Act became

law. Consequently, we recommend that the Commission reject DEC's request for a $200 million annual increase in its revenue requirement.

CIGFUR III Brief, pp. 23-24.

CIGFUR III stated that as a result of the analysis performed by the Tech Customers witnesses and the Company's failure to present compelling evidence of financial harm, it contends that DEC's request to increase its annual revenue requirement by $200 million is unnecessary and should be rejected.

CUCA argued in its post-hearing brief that DEC's rates should be adjusted to give customers full credit for the reduction in the Federal corporate income tax rate from 35% to 21% contained in the Tax Act. CUCA asserted that giving the customers the full benefit of a 100% flow through of this federal income tax reduction will help to soften the economic blow to consumers' budgets that will result from any rate increase approved by the Commission in this case. CUCA noted that DEC, however, argued that the benefits of the Tax Act should not be 100% flowed through to the customers right away and instead, the customers should be required to accept a delayed payment of some of the benefits of the tax reduction while DEC makes other uses of the customers' money.

CUCA asserted that the "math in this situation does not require a rocket scientist to solve": Federal income tax rates are reduced from 35% to 21% and the "gross up" that DEC requires to account for income taxes is significantly reduced. CUCA stated that if the effective tax rates (like any other item of expense) go down, it has to follow that the utility's revenue requirement also must go down. CUCA Brief, p. 15. CUCA argued that the revenue requirement impact of a reduction in the federal corporate income tax rate from 35% to 21% is a finite, calculable amount. CUCA asserted that customers should immediately receive, as soon as any new rates for DEC become effective, the full benefit of this tax reduction. CUCA opined that DEC should not be able to place a hold on what is, fundamentally, the ratepayers' money by any sort of delayed refund mechanism. CUCA maintained that such a delay puts ratepayers in the position of having to pay "phony" or "phantom" income taxes as a part of the overall utility revenue requirement. CUCA Brief, p. 15.

CUCA noted that DEC argued that, unless it could delay reducing rates by the full amount of the tax reduction, it would be forced into a position of having to borrow working capital funds and that its credit rating could be seriously undermined. CUCA noted that the Supplemental Testimony of the Tech Customers witnesses clearly refutes this argument. CUCA stated that the supplemental testimony shows that DEC will not experience any funding difficulties and will not incur any sort of erosion or damage to its credit rating.

CUCA asserted that to the extent the Commission allows DEC, as DEC has requested, to delay the full impact of the Tax Act tax reductions, then the customers and ratepayers are, in essence, being required to provide an interest free loan to the DEC stockholders. CUCA argued that if the Commission allows this, then the amounts of the

Tax Act tax refunds that are not immediately flowed through should bear interest, to be ultimately repaid to the customers, at an annual rate of not less than 10% of the value of the delayed refund during the time of such delay. CUCA stated that that is the only way in which the ratepayers can be made whole for the loan they would be forced to make to the DEC stockholders. CUCA stated that, in addition, if DEC is allowed to delay the full impact of the tax refund implemented by Congress and the President, this delay will tend to reduce the business, financial, and operating risks of DEC. CUCA argued that, therefore, in addition to the payment of interest, the Commission should reduce the rate of return on equity awarded to DEC because of the risk reduction.

The Justice Center et al. stated in their post-hearing brief that the recent changes to federal tax law give the Commission an opportunity to mitigate the impact of any rate increase on the Company's most vulnerable customers. The Justice Center et al. noted that DEC has collected a large pool of unprotected EDIT. The Justice Center et al. urged the Commission to direct $5 million of the EDIT to the Helping Home Fund, which provides efficiency upgrades to low-income customers, for each year of the period over which the EDIT is amortized to flow back to ratepayers. The Justice Center et al. argued that at the same time, the Commission should reject DEC's request to retain $200 million in ratepayer dollars per year as cash-flow protection for the Company.

The Justice Center et al. noted that at the Greensboro public hearing, the executive director of the NCCAA, Sharon Goodson, recommended that the Company contribute up to $5 million annually to the Fund. Tr. Vol. 2, pp. 21-22; Goodson Ex. 1. The Justice Center et al. asserted that a $5 million annual contribution from DEC's unprotected EDIT represents less than 14 percent of the total unprotected EDIT that will flow back to ratepayers, and a smaller percentage of the overall EDIT that is owed to ratepayers.

The Justice Center et al. maintained that there is precedent for using a regulatory liability for the benefit of customers to fund energy-efficiency investments for the utility's low-income customers. The Justice Center et al. noted that the Helping Home Fund itself was originally funded with $10 million of a $20 million regulatory liability from DEP held for the benefit of its North Carolina retail customers.

In addition, the Justice Center et al. stated that sound policy reasons support directing a meaningful portion of the unprotected EDIT for targeted investments in low-income energy efficiency, rather than simply flowing all of the funds to ratepayers through rebates or a decrement rider. The Justice Center et al. maintained that utility investments in energy efficiency help to alleviate high energy burdens faced by low-income households, particularly when those households are faced with rate increases. The Justice Center et al. argued that low-income households, racial minorities, renters, and low-income customers residing in multifamily buildings experience higher than average energy burdens, meaning that they pay a higher percentage of their income on energy bills than their counterparts. The Justice Center et al. asserted that the Southeast faces some of the highest energy burdens in the nation and that households with high energy burdens must face difficult trade-offs between paying utility bills and paying for other necessities such as food, prescriptions, transportation, and medical care.

Tr. Vol. 8, pp. 33-38. The Justice Center et al. also stated that low-income households are more likely than the average household to have older and less efficient appliances. The Justice Center et al. stated that by lowering energy costs during periods of high demand, and avoiding or deferring the need to build or upgrade expensive new power plants and transmission infrastructure, investments in energy efficiency also bring system-wide benefits that are shared by all customers. The Justice Center et al. stated that each dollar invested in energy efficiency yields up to four dollars in benefits for customers.

The Justice Center et al. noted that at the evidentiary hearing in this matter, DEC witness Fountain recognized that it would be appropriate for the Commission to direct a portion of the unprotected EDIT for the benefit of low-income customers. The Justice Center et al. stated that when asked whether the Company would object to allocating a portion of unprotected EDIT to the Helping Home Fund, witness Fountain agreed that the Commission could use a portion of the unprotected EDIT for low-income energy-efficiency measures: "the Tax Act is a tool that the Commission has before it that it can use to mitigate customers' rate impacts in a variety of different ways, and…there could be some considerations for low-income customers….it's a very useful tool for the Commission to be able to have." Tr. Vol. 7, p. 57. The Justice Center et al. stated that, moreover, witness Fountain agreed that there was precedent for using a regulatory liability held by the Company for the benefit of ratepayers to support the Helping Home Fund. Id. at 58. The Justice Center et al. noted that Commissioner Patterson asked witness Fountain whether the Helping Home Fund has been favorably received and whether DEC had considered making additional contributions to the Fund in the context of this general rate case. Tr. Vol. 9, pp. 111-12. The Justice Center et al. maintained that while witness Fountain praised the program, he acknowledged that the Company has made no commitment to further support the program from shareholder dollars or otherwise in this rate case.[50] Id. The Justice Center et al. stated that similarly, Commissioner Clodfelter and Chairman Finley urged DEC to consider additional ways to meet the needs of low-income customers, including consideration of the Ohio Percentage of Income Payment Plan and the Missouri "Dollar More" program. Tr. Vol. 9, pp. 97-98; 114-15.

The Justice Center et al. maintained that DEC's failure to offer any assistance to its low-income customers to mitigate the effects of its proposed increase in rates and charges should be relevant to the Commission's decision whether to grant any of those requested increases. See, e.g., Order Granting General Rate Increase, Docket No. E-2, Sub 1023, p. 82 (May 30, 2013) (finding that funding of low-income assistance programs "is a just and reasonable measure to mitigate the impact of the proposed rate increase on . . . low-income customers"). The Justice Center et al. noted that the potential impact of new rates on customers is a "critical consideration" in the Commission's determination on whether to accept those new rates. Cooper, 366 N.C. at 495, 739 S.E.2d at 548 (holding that the Commission must consider the impact of changing economic conditions on customers when determining return on equity for a public utility). The Justice Center

[50] On June 1, 2018, DEC made a shareholder-funded commitment of $4 million for programs including those to assist low-income customers.

et al. asserted that to the extent that the Commission grants any component of DEC's request for a rate increase, it would be reasonable to order the allocation of $5 million per year of DEC's unprotected property, plant, and equipment EDIT to the Helping Home Fund for as long as that EDIT is amortized to flow back to ratepayers.

Kroger asserted in its post-hearing brief that customers should receive the full benefit of the tax savings provided by the Tax Act. Kroger noted that the reduction in the corporate income tax rate per the Tax Act will reduce DEC's federal income tax expense for regulatory purposes and that this reduction in tax expense should directly reduce the revenue requirement in this case. Kroger stated that viewed in isolation, this single component of the change in tax law, i.e., the reduction in the tax rate from 35 percent to 21 percent, reduces DEC's revenue requirement by a significant amount.

Additionally, Kroger noted that the Tax Act has implications for DEC's ADIT. Kroger stated that DEC accumulates these deferred income taxes in the ADIT on its regulatory books in an amount equal to this anticipated future tax liability. Kroger asserted that now that the corporate income tax rate has been reduced by 40 percent, DEC's anticipated future tax liability has also decreased by a comparable amount. Kroger noted that as of January 1, 2018, when the new tax rates became effective, a substantial portion of the ADIT on DEC's books will be considered to be "excess" ADIT. Kroger asserted that this excess ADIT should be returned to customers.[51]

Kroger recommended that the Commission reduce the revenue requirement in an amount that provides customers with the full benefit of the tax savings provided by the Tax Act and that the Company's revenue requirement in this case should be adjusted to reflect the direct impact to its cost-of-service and excess ADIT should be credited to customers starting with the rate effective period in this general rate case.

NCLM noted in its post-hearing brief that its witness Brian W. Coughlan provided testimony that DEC's rates should be adjusted downward to account for the significantly lower corporate income tax rates that DEC will pay since the enactment of the Tax Act. Tr. Vol. 8, pp. 105-107. NCLM noted that its Settlement Agreement with DEC did not resolve the issues raised by NCLM as to adjusting all rates downward to account for the lower corporate income tax rates in the Tax Act. NCLM stated that DEC's unanticipated tax savings should be used to mitigate any rate increase.

NCLM stated that its witness Coughlan addressed this issue in his testimony to supplement the Commission's work in Docket No. M-100, Sub 148. Tr. Vol. 8, pp. 105-107. NCLM noted that witness Coughlan simply asserted that, "[t]he new tax cuts should be taken into account now. The new tax rates take effect before the new electric rates will take effect. If the new tax rates are not accounted for at this time, DEC will have significantly higher than expected and appropriate earnings, and DEC customers will pay unfairly high rates between now and the next rate case." Id. at 106. NCLM respectfully requested that the Commission allow rate payers to benefit from the tax cuts to the maximum extent possible in this docket.

[51] Direct Testimony of Kevin Higgins, pp. 6-7.

The Tech Customers asserted in their proposed order and post-hearing brief that the Commission is required in this general rate case to, among other things, account for the Company's operating expenses for the test year, taking into account "evidence … tending to show actual changes in costs". See, e.g., N.C. Gen. Stat. §§ 62-133(b)(3) and (c). The Tech Customers stated that given this requirement, the effects of the Tax Act as to the rates charged by the Company should be addressed in this general rate case rather than the separate, generic proceeding that the Commission has initiated in Docket No. M-100, Sub 148. The Tech Customers asserted that the Public Staff's proposal for return of EDIT best balances the need to return tax overcollections to ratepayers as promptly as possible with the appropriate regulatory goals of avoiding adverse rate impacts for ratepayers and allowing sufficient time for DEC to manage its cash flow so as to avoid negative impacts to its credit metrics.

Further, the Tech Customers maintained that DEC's proposal to offset the reduction in its revenue requirement resulting from the Tax Act with $200 million in accelerated depreciation expense is not sufficiently supported in the record and raises significant legal and practical concerns. The Tech Customers argued that a decline in revenues resulting from a change in federal tax law does not, by itself, support the adoption of offsetting revenue increases where those increases are not independently justified and supported.

The Tech Customers noted that given that the issue relating to the implementation of federal tax reform was introduced into this proceeding after the filing of testimony by the parties, the parties have addressed this issue through supplemental testimony, examination at hearing, and in post-hearing briefing.

The Tech Customers noted that they offered Supplemental Testimony of witnesses Strunk and Brown-Hruska. The Tech Customers witnesses evaluated the reasonableness of DEC's contention that a $200 million annual increase in spending was necessary to support its credit metrics. The Tech Customers stated that based on the projected FFO/Debt ratios offered by DEC witness De May and a review of the most recent credit assessment of Standard and Poor's, witnesses Strunk and Brown-Hruska found that DEC's projected FFO/Debt ratios, adjusted to eliminate the request for an additional $200 million in cash flow, do not jeopardize the Company's credit metrics. Tr. Vol. 26, p. 514. The Tech Customers stated that, instead, their analysis study shows that DEC is on track to maintain, or even exceed, its stated FFO/Debt ratio goal after implementation of federal tax reform. Id. The Tech Customers maintained that witnesses Strunk and Brown-Hruska also compared DEC's FFO/Debt ratio to those of comparable companies, including those in witness Hevert's proxy group, and found that DEC's ratios are in line with, or above, those of the comparable companies and that its FFO/Debt ratios are among the healthiest among the proxy group companies both on a current and projected basis. Id. at 516-517. Based on this analysis, the Tech Customers noted that their witnesses concluded that DEC's rationale for its proposal was inconsistent with the financial forecasts it has provided in its own exhibits and not necessary to protect its current credit standing. Id. at 519.

The Tech Customers stated that the Commission is required in this general rate case to, among other things, account for the Company's operating expenses for the test year taking into account "evidence . . . tending to show actual changes in costs." See, e.g., N.C. Gen. Stat. § 62-133(b)(3) and (c). The Tech Customers asserted that this statute suggests, if not mandates, that the Commission implement tax reform in this proceeding.

Further, the Tech Customers stated that they agree with the Public Staff's recommendations concerning EDIT. The Tech Customers stated that they do not find support in accounting or ratemaking principles for the distinction in unprotected EDIT advocated by DEC. The Tech Customers stated that the PP&E assets for which DEC seeks a 20-year amortization period, like other unprotected EDIT, are not subject to IRS normalization rules. The Tech Customers asserted that Congress intentionally excluded EDIT from unprotected assets from the treatment given to protected EDIT because the excluded assets do not have normal useful lives. The Tech Customers noted that DEC asserted that unprotected PP&E EDIT is similar in nature to protected EDIT (which is also related to PP&E) and therefore it is reasonable to flow it back over a similar period. Tr. Vol. 5, p. 78. However, the Tech Customers stated that they can discern no principled basis for distinguishing between the assets in the manner proposed by the Company and an examination of the specific assets in this category suggests that they include assets (e.g., casualty loss, depreciation lag, AFUDC debt, pension cost) with highly uncertain accounting lives. See DEC Response to Public Staff Data Request No. 155-3, filed March 22, 2018.

Moreover, the Tech Customers argued that 20 years is simply too long a period over which to return over-collected ratepayers' money, and DEC has offered no evidence suggesting otherwise. In this regard, the Tech Customers stated that they are sympathetic to the need to return tax over-collections as expeditiously as possible. See, e.g., Buckeye Pipe Line Co., 13 FERC ¶ 61267, 61594 (1980) ("Millions of the Americans who use [electricity] live in poverty or on very tight budgets. Those people are in no position to lend money to anybody. A state of affairs that compels them to supply . . . electric companies with long-term credit in amounts that may sometimes seem minuscule on a per capita basis to the affluent but that are almost always material to the poor and to those who are just getting by cannot be viewed complacently.").

The Tech Customers noted that DEC has also raised concerns about the impact of the EDIT flowback on its cash flow that it speculates could negatively impact its credit metrics. Tr. Vol. 5, pp. 67-83. While the Tech Customers acknowledged the concerns raised by DEC, as well as the benefits that ratepayers derive from the Company's strong credit profile, the Tech Customers recommended that the Commission conclude that DEC's evidence on this point is not compelling or convincing.

Moreover, the Tech Customers noted that the Company's concerns over cash flow and credit metrics are mitigated, to an extent, by the Public Staff's five-year flow back proposal that provides the Company with the benefit of removing the total amount of the unprotected EDIT credit from the rate base in the current case, which benefits the Company by increasing rates and thereby moderating any cash flow issues, to the extent they may arise. The Tech Customers asserted that the financing cost to the Company will be imposed ratably over the period that the EDIT is returned through the levelized rider.

Finally, the Tech Customers recommended that the Commission conclude that DEC's proposal to offset the reduction in its revenue requirement resulting from the Tax Act with $200 million in accelerated depreciation expense is not sufficiently supported in the record and raises significant legal and practical concerns. The Tech Customers maintained that a decline in revenues resulting from a change in federal tax law does not, by itself, support the adoption of offsetting revenue increases where those increases are not independently justified and supported. The Tech Customers asserted that aside from the desire to offset reductions resulting from the change in tax law, the Company has not offered any principled explanation of the need for accelerated depreciation nor has it offered any basis for applying special depreciation rates for particular assets. The Tech Customers noted that DEC does articulate concerns about adverse rate impacts on consumers, but the Tech Customers support a five-year return of EDIT that will help ameliorate adverse impacts resulting from the return of EDIT. Moreover, the Tech Customers maintained that as to DEC's credit metrics, record evidence suggests that DEC's projected FFO/Debt ratios, adjusted to eliminate the proposed additional $200 million in cash flow, will not jeopardize the Company's credit metrics. Tr. Vol. 26, p. 514. The Tech Customers stated that, instead, evidence suggests that DEC will be on track to maintain, or even exceed, its stated FFO/Debt ratio goal after implementation of federal tax reform without an annual $200 million revenue increase. Id.

In light of the parties' testimony and all of the evidence presented, the Commission finds and concludes that it is appropriate to: (1) recognize a $211,512,000 per year reduction in DEC's revenue requirement to reflect the current 21% Federal corporate income tax rate; (2) deny DEC's proposed $200 million per year credit metric mitigation measure; and (3) allow DEC to continue to maintain all EDIT related to the Tax Act in a regulatory liability account for three years or until its next general rate case, whichever is sooner, at which point it will be returned to DEC's customers with interest reflected at the overall weighted cost of capital approved in this case of 7.35%. The Commission concludes that this approach appropriately balances the interests of DEC and its ratepayers.

The evidence shows that there is some agreement between the parties regarding how to implement the effects of the Tax Act. The Company and the Public Staff agree upon the revenue requirement effect of the decrease in the corporate income tax rate, the repeal of the manufacturing tax deduction, and the elimination of bonus depreciation. No party disputes the amounts presented by the Company and the Public Staff regarding the impact of the Tax Act on these issues, and the Commission finds and concludes that the revenue requirement changes presented by the Company and the Public Staff related to these issues are appropriate and should be approved. This decision results in a $211,512,000 per year reduction in DEC's revenue requirement.

Further, the Commission gives great weight to the testimony of the Public Staff, the AGO, CIGFUR III, the Justice Center et al., Kroger, NCLM, and the Tech Customers that DEC's proposed $200 million per year credit metric mitigation measure is inappropriate and should be denied. Therefore, the Commission declines to allow the Company to include an additional $200 million in its annual revenue requirement for the purpose of offsetting the impacts of the Tax Act on DEC's revenue requirement.

The Commission agrees with the Public Staff that DEC's request amounts to essentially eliminating the benefit of the corporate income tax decrease on the Company's ongoing expenses. DEC's request for this extraordinary relief was presented in very vague and uncertain terms; the Company simply mentioned a few possible uses for the additional $200 million in annual revenue. None of the Company witnesses could even articulate the reason for the $200 million number, nor could they provide a breakdown of what that number represents, other than that witness De May felt the number to be appropriate. The Commission further agrees with the Tech Customers that a decline in the tax rate does not support the adoption of an offsetting revenue requirement increase that is not independently justified and supported. The Commission also agrees with the Tech Customers that adoption of the $200 million proposal would raise significant legal and practical concerns. Moreover, as noted by the Public Staff, the request was not time-limited; in theory, the additional $200 million in revenue requirement would equate to $1 billion after five years. Finally, the Commission finds and concludes that offsetting known and measurable reductions in taxes to be paid going forward against the recovery of unknown ongoing coal ash basin closure costs as ultimately proposed by DEC in its Post-Hearing Brief and Proposed Order in this docket in order to delay reflecting the current Federal corporate income tax rate in base rates constitutes inappropriate ratemaking.

The Commission finds that the $200 million in additional annual revenue requirement appears solely designed to arbitrarily inflate the Company's revenue requirement beyond the actual cost of service. The Company essentially seems to be telling ratepayers that they can receive the reduction in the tax rate, but they have to pay most of it back through accelerated depreciation expenses. The Commission rejects this proposal as arbitrary. The Commission is confident that the Company's management can navigate this situation without artificial and arbitrary adjustments to annual revenue requirement. The Commission concludes that the Company's request for an additional $200 million per year as a credit metric mitigation measure is not supported by the preponderance of the evidence and therefore is denied.

Finally, the Commission notes that DEC filed its rate case application in August 2017, four months before the enactment of the Tax Act. The Commission finds that it is appropriate to recognize this fact in rendering its final decision in this matter. The Tax Act is the most significant federal tax legislation since the 1986 Tax Act enacted some 30 years ago. Based on this fact and finding that the evidence presented by DEC concerning its credit metrics and a possible credit downgrade merit some weight, the Commission concludes that DEC shall maintain all of its EDIT in a regulatory liability account pending flow back of that liability to DEC's ratepayers with interest reflected at the overall weighted cost of capital approved in this case of 7.35% in three years or in DEC's next general rate case proceeding, whichever is sooner. If DEC has not filed an application for a general rate case proceeding by June 22, 2021, it shall file its proposal by that date to flow back to its ratepayers both the protected and the unprotected EDIT generated due to the Tax Act. The federal EDIT flowback proposal should include all workpapers that support the proposed calculations. The Public Staff is specifically requested to file comments on the proposal by no later than July 22, 2021. Other parties also may file comments on the proposal by no later than July 22, 2021.

The Commission notes that in the generic rulemaking proceeding established by the Commission to address the recent changes in the State corporate income tax rate (Docket No. M-100, Sub 138), the Commission concluded that EDIT for all utilities, as appropriate, were to be held in a deferred tax regulatory liability account until they could be amortized as reductions to income tax expense for ratemaking purposes in each utility's next general rate case proceeding. The Commission stated that it agreed with PSNC Energy's comments in that docket that recognizing the amortization of the EDIT in the next general rate case of a utility would provide for certainty as to the amount to be amortized instead of having to base the flow-back calculation on an estimate. In that proceeding, no party objected to that option of handling the EDIT. In addition, the Commission noted in its May 13, 2014 Order in the generic proceeding that both Carolina Water Service, Inc. of North Carolina (CWSNC) and Aqua had had open rate case proceedings at the time the generic State tax docket was initiated. A rate order was issued in CWSNC's rate case docket on March 10, 2014, and a rate order was issued in Aqua's rate case docket on May 2, 2014. The Commission concluded in the May 13, 2014 Order that the expense piece of the State corporate income tax rate change was reflected in the rates established in the CWSNC and Aqua open rate case proceedings, but that CWSNC and Aqua needed to adhere to the findings on State EDIT outlined in the May 13, 2014 Order. The May 13, 2014 Order concluded for the State EDIT that each utility was to hold the State EDIT in a deferred tax regulatory liability account until they could be amortized as reductions to income tax expense for ratemaking purposes in each utility's next general rate case proceeding. The Commission's decision herein is reasonably consistent with the treatment of CWSNC and Aqua in the generic State corporate income tax proceeding.

Further, the Commission notes that this process used in Docket No. M-100, Sub 138 has worked well and customers received or are receiving EDIT related to the State corporate income tax rate changes. In fact, in this proceeding, DEC and the Public Staff stipulated to begin returning (four years after the Commission's State EDIT decision in the May 13, 2014 Order in the generic rulemaking docket) to DEC's customers the State EDIT through a four year decrement rider.

In addition, the Commission notes that in the Commission's 1986 federal corporate income tax law change generic rulemaking proceeding (Docket No. M-100, Sub 113), the Commission concluded in its October 20, 1987 Order to Require Filing of Tariffs to Reduce Rates and Refund Plans to Effect Flow Through of Tax Savings for Those Regulated Companies not covered by Specific Orders on This Matter (1987 Order), as follows:

> [t]hat the appropriate amortization of accumulated excess deferred income taxes will be considered in each company's next general rate case or such other proceeding as the Commission may determine to be appropriate. Any additional amounts relating to the adjustment that should have been made by the company for the flowback of excess deferred income taxes shall be placed in a deferred account and should ultimately be refunded to ratepayers with interest.

1987 Order. Although this conclusion was reached in a generic rulemaking proceeding, the Commission concludes that the fact that DEC had already filed its rate case application before the enactment of the Tax Act in this instant proceeding, it is appropriate to follow this same process for returning Federal EDIT to DEC's ratepayers.

However, the Commission, in its discretion, concludes that it is appropriate in this case to set a time limit for DEC to retain all of the EDIT generated due to the Tax Act. The Commission concludes that it is preferable to address this EDIT in a rate case proceeding; but due to the sheer magnitude of the EDIT that in total is approximately $2.14 billion, the Commission finds that DEC must begin the process to flow back the EDIT to ratepayers no later than three years from the date of this Order (or sooner if DEC files a rate case in less than three years). Therefore, the Commission concludes that if DEC has not filed an application for a general rate case proceeding by June 22, 2021, it shall file its proposal by that date to flow back to its ratepayers both the protected and the unprotected EDIT generated due to the Tax Act. The federal EDIT flowback proposal should include all workpapers that support the proposed calculations. The Public Staff is specifically requested to file comments on the proposal by no later than July 22, 2021. Other parties also may file comments on the proposal by no later than July 22, 2021.

In conclusion, the Commission finds it appropriate to: (1) recognize a $211,512,000 per year reduction in DEC's revenue requirement to reflect the current 21% Federal corporate income tax rate; (2) deny DEC's proposed $200 million per year credit metric mitigation measure; and (3) allow DEC to continue to maintain all EDIT related to the Tax Act in a regulatory liability account for three years or until its next general rate case whichever is sooner at which point it will be returned to DEC's customers with interest reflected at the overall weighted cost of capital approved in this case of 7.35%. The Commission concludes that this approach appropriately balances the interests of DEC and its ratepayers.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 59-64

The evidence supporting these findings of fact and conclusions is found in the Company's verified Application, DEC's Petition for an Order Approving a Job Retention Rider (JRR), filed on August 14, 2017, in E-7 Sub 1152 (JRR Petition), the testimony of Company witness Pirro, the testimony of Public Staff witness McLawhorn, the testimony of other witnesses, the exhibits of witness Pirro, and the entire record in this proceeding. The Commission takes judicial notice of the Company's Initial and Reply Comments filed in Docket No. E-100, Sub 73 where the Company outlined the conditions that led to the loss of industrial jobs and where the Commission issued establishing guidelines on December 8, 2015. (JTR Order)

In its Petition, DEC requests approval of its JRR, a five-year pilot program for industrial customers that is intended to curtail further loss of industrial jobs in DEC's service territory. Petition, at p. 1. The Commission acknowledged the JRR's goal to stem further loss of industry, industrial production and industrial jobs in DEC's service territory as an important policy goal for North Carolina when it adopted the Guidelines for Job Retention Tariffs in Docket No. E-100, Sub 73. Petition at p. 3. Company witness Pirro testified in support of the Company's proposed JRR. Witness Pirro explained that the JRR will benefit ratepayers by retaining North Carolina jobs and strengthening local economies thereby aiding the commercial and residential markets. Tr. Vol. 19, p. 95. Since 2014, 50 manufacturing facilities served by Duke Energy have ceased operation in North Carolina. Id. at 78, 90. Witness Pirro states that the Company's IRP Update, filed on September 1, 2017 in Docket No. E-100, Sub 147, demonstrates the continuing struggles of manufacturing in North Carolina. Tr. Vol. 19, p. 90. He testifies that "[t]he Plan shows a steady decline in the number of industrial customers receiving electric service and our expectation [is] that even by 2023 industrial sales will still be below actual pre-recession sales realized in 2007." Id.

Witness Pirro also explained the eligibility requirements for the proposed JRR. Customers that use electric power as a principal motive power for the manufacture of a finished product, the extraction, fabrication or processing of a raw material, or the transportation or preservation of a raw material or a finished product would be eligible for the Company's proposed JRR. Id. at 90-91. Furthermore, in order to qualify for JRR, industrial customers must show that they (i) have or are considering the ability to shift production from their facilities to facilities in other states or countries; (ii) are considering a need to reduce the employment level at their facilities due in whole or in part to the impact of electricity cost; (iii) intend to reduce or are presently evaluating reduction of production levels or load due in whole or in part to the impact of electricity cost; or (iv) have load that is otherwise at risk of loss. Petition at p. 5. Additionally, eligible customers must have an aggregate electrical load of 3,000 kW or greater, in addition to other conditions described in the Petition and proposed JRR. Tr. Vol. 19, p. 91.

In its Petition, the Company does not seek recovery of the revenue reduction resulting from implementation of the JRR at this time, but instead requests deferral accounting with interest on the amount in excess of the $4.5 million that the Company will absorb on a one-time basis. Petition at p. 3.

CUCA witness O'Donnell testified in support of the Company's proposed JRR. Witness O'Donnell testified that if DEC continues to lose industrial load, the fixed costs of operating the DEC system will be shifted to the remaining customers in an amount even greater than the average 0.74% cited in DEC's Petition. Tr. Vol. 18, pp. 54-55. For example, witness O'Donnell calculated that if the Company's manufacturing load completely eroded, the remaining customers' rates would increase by over 16% annually.

Id. at 55. He concluded that it would be much less harmful to residential customers to pay a 0.74% increase for five years than to have a permanent 16.22% increase. Id.

CIGFUR III witness Phillips also testified in support of the Company's proposed JRR. Witness Phillips testified that the Company's proposed JRR follows the Guidelines for Job Retention Tariffs issued by this Commission on December 8, 2015 in Docket E-100, Sub 73, and that the proposed JRR is in the public interest, and recommended that the Commission approve it. Tr. Vol. 26, p. 280. Witness Phillips testified that his review of DEC's historic and projected growth in customers indicated that within the 2007 to 2032 timeframe, the Company will see residential customers increase by 32.2%, commercial customers increase by 23.3%, and industrial customers decrease by 28.6%. Id. at 281. Witness Phillips testified that the proposed JRR will benefit all customers because "[i]f industrial load is lost, DEC would need to recover a larger portion of fixed costs from its remaining customers, resulting in higher electric rates for these customers." Id. at 282. Therefore, preserving jobs and industrial load through the Company's proposed JRR will strengthen the economy and keep electric rates lower for DEC's non-industrial customers. Id. Witness Phillips also testified that the Commission's guidelines in Docket No. E-100, Sub 73 do not exclude pipeline customers that are also important to the North Carolina economy. Id. at 283. Therefore, he testified that it would be unreasonable to impose restrictions on the Company's proposed JRR that exclude those customers. Id. at 284.

While the Public Staff is supportive of the JRR and believes that it is in the public interest, witness McLawhorn expressed several concerns regarding the proposed rider. Tr. Vol. 20, pp. 141-46. First, witness McLawhorn expressed concern with the availability of the rider to customers involved in the "transportation or preservation of a raw material of a finished product," which is understood to include gas pipeline customers. Id. at 141-42. He noted that pipelines are different than other industrial manufacturing facilities in that pipelines are fixed investments that are not easily relocated to another area, and unlike other industrial manufacturers, pipelines do not produce a finished product. Id. at 142. He recommended this disputed phrase be eliminated from the availability section of Rider JRR-1. Second, he argued that there are no specific criteria designated for use by the Public Staff to evaluate customer employment and financial records to aid in evaluating an applicant's justification for seeking the JRR thus depriving the Public Staff of the ability to verify the truthfulness of the information. Id. at 142-44. He also opposed the Company's request for deferral accounting of the revenue loss and the Company's proposal for sharing the discount between the Company's shareholders and ratepayers. Id. at 146. Lastly, witness McLawhorn recommended that the requirement that the discounted revenue must be used to retain jobs in North Carolina be more prevalently displayed in the Application form and that the language in the compliance filing clearly identify the length of the JRR from initial approval. Id. at 145-46.

Despite these concerns, the Public Staff generally supports the Company's proposed JRR, concluding that the rate reduction it provides for industrial customers would "assist them in maintaining jobs and load in North Carolina." Id. at 139-40. Witness McLawhorn testified that the Company's proposed JRR complies with the Commission's

Guidelines for Job Retention Tariffs set forth in its December 8, 2015 order in Docket No. E-100, Sub 73. Tr. Vol. 20, pp. 134-38. Witness McLawhorn also testified that the proposed JRR is not unduly discriminatory because it is designed to reach the largest industrial customers, which impact other commercial and residential customer classes. Tr. Vol. 20, p. 138. Witness McLawhorn further stated that the proposed JRR "provides for a balancing of benefits and costs between those customers eligible for [JRR] and those that will bear the reduction in revenue that result from implementation of the rider." Id. at 139. Lastly, witness McLawhorn recommended that the impact of the rate discount be recovered from all retail ratepayers, including the customers eligible for the rate discount. Id. at 147.

Commercial Group witnesses Chriss and Rosa testified in opposition to the Company's proposed JRR. Witnesses Chriss and Rosa state that the proposed JRR fails to comply with Commission guidelines by limiting applicability to a subset of industrial customers and the rigor of verifying customer attestations is unclear. Tr. Vol. 26, p. 547. Witnesses Chriss and Rosa further request that if the JRR is approved, that it be extended to non-industrials that also provide jobs and have aggregate loads of 3,000 kW or greater. Id.

In its post-hearing Brief, Commercial Group continues to advocate a denial of the JRR. However, Commercial Group recognizes that the Commission approved a more limited JRR for DEP in DEP's rate case which included five safeguards, which the Commercial Group contends should be adopted in this case if approved. Commercial Group submits that the JRR would violate N.C. Gen. Stat. § 62-140(a) because it would unjustly discriminate among customers having an aggregate load of at least 3 MW based solely on whether the customer is an industrial customer. Commercial Group contends that this is a return to the Standard Industrial Classification (SIC) code distinctions that the Commission found discriminatory and rejected in prior proceedings. Commercial Group states that the Commission stated its concern in its final Order in DEC's 2011 rate case, Docket E-7 Sub 989, regarding the reasonableness and fairness of maintaining a rate differential based largely on labels such as the SIC codes. Commercial Group quotes N.C. Gen. Stat. § 62-140(a), and states that the legal standard is not whether a public utility can subject a customer to an unreasonable prejudice or disadvantage if doing so would be an advantage to other customers or the utility. Rather, the legal standard is that the public utility cannot grant any unreasonable preference or subject any person to any unreasonable prejudice or disadvantage. Further, Commercial Group contends that industrial customers are not a separate class of service because both industrial and commercial customers are members of the same OPT-V class, and that many non-industrial ratepayers in these classes have an aggregate load of at least 3 MW. According to Commercial Group, where the JRR's only distinguishing characteristic is industrial status, the JRR remains as unlawful and unduly discriminatory as the preference for OPT industrial customers that the Commission previously rejected, and, therefore, the JRR as proposed should be rejected as well.

In addition, Commercial Group states that the proposed JRR definitions and parameters that DEC selected provide only an illusion of being reasonable criteria for determining which customers should receive a rate subsidy. As an example, Commercial Group contends that the applicant could simply state that it has at some time in the past thought about obtaining the ability to move a portion of its operations out of state, but the applicant need not presently have such ability, presently plan to move operations out of state, nor be in such financial condition that jobs would be lost but for a JRR subsidy. Commercial Group further notes that the applicant does not need to maintain existing levels of employment, but instead chooses a level of employment that it states it will maintain, even if the level is lower than its present level.

Commercial Group notes that DEC witness Hevert gave convincing testimony that economic conditions in North Carolina have improved substantially since DEC's last rate case in 2013, and since the Commission adopted job retention guidelines in 2015. The unemployment rate in North Carolina and DEC's service territory has fallen substantially during these periods. Tr. Vol. 4, pp. 161, 165. Further, the correlation between the drop in unemployment in North Carolina and more broadly across the United States has been very high. Id. at 165. Moreover, DEC industrial customers already receive competitive rates that are below the national average and below the average in the Atlantic South region.

Commercial Group questions whether there will be a means to assess the effectiveness of the JRR. Commercial Group cites the testimony of Public Staff witness McLawhorn regarding the report that DEC will be required to file, and states that the report will not provide any reliable, independently verifiable information to determine the success or failure of the JRR. Based on the uncertainty of verifiable results from the JRR, Commercial Groups requests that the Commission should require the same safeguards that it required of DEP for its JRR in DEP's most recent rate case.

Company witness Pirro's rebuttal testimony responded to the concerns raised by other witnesses related the Company's proposed JRR. Witness Pirro agreed with the Public Staff's concern regarding difficulty evaluating customer financial and employment records. Tr. Vol. 19, p. 92. To address this concern, witness Pirro explained that DEC will impose a requirement that an officer of the customer sign the application and the signature be notarized. Id. Witness Pirro also noted that the guidelines don't require a demonstration of financial distress, but the discounted revenue must contribute to job retention in North Carolina. Id.

Additionally, witness Pirro testified regarding the inclusion of customers involved in the "transportation or preservation of a raw material of a finished product", that this language was included to allow the JRR to apply primarily to gas pipeline customers. Id. at 92. He stated that pipeline customers have expressed concerns with electricity costs and have requested rate relief to aid in their North Carolina operations. Id. DEC believes that it is reasonable to include this type of customer with manufacturing facilities when applying the JRR. Id.

Witness Pirro further testified that deferral accounting was requested because the timing and magnitude of the revenue reduction is unclear. Id. at 93. "The use of deferral accounting allows the Company to assess the true impact of the rider and seek recovery at a later date when revenues are more certain." Id. at 93-94. Witness Pirro also disagreed with witness McLawhorn's recommendation that the Company's shareholders absorb $4.5 million every year the rider is in effect. Id. at 95. Witness Pirro testified that the JRR will benefit ratepayers by retaining North Carolina jobs and strengthening local economies thereby aiding the commercial and residential markets. Id. While the Company's shareholders are willing to absorb a portion of the revenue reduction in the first year to implement the program, a requirement that shareholders absorb this cost in subsequent years would deprive the Company of a reasonable opportunity to recover its just and reasonable costs. Id.

Lastly, Witness Pirro agreed with witness McLawhorn's requested two changes to the application form and tariff. Id. at 93. He explained that the Company does not oppose the relocation of the statement regarding the discounted revenue being used to retain jobs in North Carolina to a more prevalent location in the Application. Id. The Company also does not object to more clearly identifying that the Rider terminate and no longer be available for service 5 years from the effective date of the Rider. Id.

In the Stipulation, the Company and the Public Staff agreed that "the Company's proposed Job Retention Rider generally complies with the Commission's guidelines adopted in Docket No. E-100, Sub 73, but two issues remain to be decided upon by the Commission: (1) whether companies involved in the transportation or preservation of a raw material or a finished product (e.g., pipeline customers) should qualify; and (2) how or if the Job Retention Rider should be funded after the expiration of the initial year's $4.5 million shareholder contribution." Stipulation, § II. c.

Except for the two unresolved issues stated above, the Stipulating Parties have agreed to the proposed JRR as described by witness Pirro in his rebuttal testimony, and further agreed that JRR revenue credits shall be recovered through a JRR Recovery Rider (JRRR) from all retail customers concurrent with JRR implementation, which is anticipated to occur approximately six months following the Commission's decision. Id. at 11, 13. The Stipulation provides that JRR and JRRR revenues shall be reported to the Commission annually and the JRRR shall be reviewed and will be subject to adjustment annually coincident with the September fuel adjustment to match anticipated recovery revenues and true-up any past over-or under-recovery. Id. at 13. Additionally, due to the uncertain date of implementation, compliance tariffs shall be filed prior to implementation of the JRRR and customers shall be notified by bill insert or message upon implementation. Id.

Company witness Pirro filed testimony and exhibits in support of the Stipulation. In his settlement supporting testimony, he explains that the recovery rate under the JRRR is set at $0.00041 per kWh to recover the first year of impact, less the $4.5 million absorbed by the Company, reduced by 10% for application lag. Tr. Vol. 19, pp. 107-08. Witness Pirro further testified that the JRRR is intended to keep the Company revenue neutral with respect to the JRR, other than the one-time $4.5 million contribution from shareholders, over the 5-year pilot period, and, if needed, a final true-up shall be applicable upon termination of JRR. Id. at 108.

The Commission finds and concludes that the Company's proposed JRR as modified by this Order is just and reasonable to all parties based on all of the evidence presented. The Commission finds that the continued loss of industrial jobs in DEC's service area will have a detrimental effect on the State. The Commission views the Company's proposed JRR as an effort to retain industrial jobs in North Carolina and concludes that implementation of the rider is in the public interest. As with other economic development tariffs previously approved by this Commission, approval of the JRR is based in part on an evaluation of the expected economic benefits resulting from the tariff. The Commission has considered the economic impact of the continuing decline of the North Carolina industrial base as well as the impact of the recovery rider on non-participating ratepayers, and concludes that the JRR strikes the appropriate balance between the two. The Commission concludes that by limiting the availability of the JRR to industrial customers, the Company has minimized the effect on non-participants while assisting the group of customers that are most in need of assistance. To further minimize the impact to non-participants and to achieve the goal of the JRR in the most cost-effective manner, the Commission shall limit the JRR to a one-year pilot, with the option of renewal for one additional year upon a showing that the JRR is achieving the intended objectives. Requiring the Company to show the Commission the effectiveness of the JRR in the rider proceeding removes any concerns expressed by the Commercial Group regarding measurement and verification. This reduction in the number of years for the pilot to one-year with the opportunity for a second year allows the Commission and the parties to assess the health of industrial sector as a whole after one year on the JRR and if an additional year would be in the public interest. In addition to the reduction of the pilot to one year, with the opportunity for a second year, the Commission determines that additional changes to the JRR are necessary for proper measurement and verification. First, the Company shall require the Customer to maintain an employment level of 90 percent of the its employees, with the number of employees determined by an average of its employment level over the twelve months prior to the filing of the Application and Agreement for the Job Retention Rider. The application shall state the specific number of employees and verify that this number represents 90 percent of the monthly average over the past twelve months. Second, the Customer shall submit in writing to DEC no later than March 1, and quarterly thereafter, a report verifying the employment level at the Customer's facility(s) receiving the Job Retention Rider credits. Third, if the Customer does not maintain the stated employee level, the Customer shall be removed from the tariff pursuant to the language in the proposed application and shall be required to refund the amount of benefits received under the JRR. DEC shall change the application language accordingly. The Commission has considered the arguments for expanding the JRR made by Commercial Group witnesses Chriss and Rosa, and concludes that expanding the JRR to other customer classes would place too large a burden on non-participants and would be unreasonable.

Furthermore, the Commission concludes that limiting the availability of the JRR to only industrial customers is not unreasonably discriminatory. Rather, it is based on a reasonable difference between customer classes, and the discount offered to participants under the JRR as compared to the amount of rider recovery on non-participants bears a reasonable proportion to the difference between the customer classes. See State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n, 348 N.C. 452, 468, 500 S.E.2d 693, 704 (1998). Based on the evidence presented, the Commission finds that industrial customers' sales have been flat or declining since the recession, while residential and commercial sales are growing. Furthermore, a \$0.003227 per kWh reduction in rates for participating industrials as compared to an increase in rates for the average retail customer of approximately \$0.000539 per kWh per month under the JRR is proportionate to differences between these customer classes and reasonable given the economic and rate benefits of retaining industrial customers on DEC's system.

The Commission concludes that the JRR, with the modifications established in this Order, is in accordance with the requirements and guidelines the Commission previously established. In the JRT Order, the Commission directed utilities to "craft eligibility requirements that are narrowly tailored to meet the intended goals of maintaining jobs in the most economically efficient manner." Although the disputed phrase that allows for the eligibility for pipeline companies was included in the JRT Order as a possible example of eligibility criteria, the Commission is not persuaded that the eligibility criteria proposed by the Company is sufficiently narrow to ensure that the JRR will maintain jobs in the most efficient manner. Pipelines, which cannot relocate, are sufficiently different from other industrial customers and should be excluded from eligibility in the JRR. The disputed phrase "or the transportation or preservation of a raw material of a finished product" should be removed from the eligibility criteria.

The Commission further concludes that the customer attestations regarding certain eligibility requirements for the JRR, as modified by this order, are reasonable and adequate. Based upon the practical considerations of managing eligibility and how eligibility for certain rates is verified in other contexts, such as the opt-out process for DSM/EE rates, the Commission concludes that the Company's proposed method for verifying eligibility for the JRR is reasonable.

Commercial Group states that it does not take issue with the Commission's gradual approach to class revenue allocation, except if the Commission grants the proposed JRR. In that event, according to Commercial Group, the Commission should use any such reduction to move each customer class closer to its respective cost of service. The Commission does not agree with Commercial Group's position. The approval of the JRR does not eviscerate the principle of gradualism in reaching rate of return equilibrium among the customer classes. Further, the rate designs approved herein and the approval of the JRR will result in just and reasonable rates.

Finally, the Commission notes that the proposed JRR is a limited-term pilot, which will allow the Commission and the Company to follow the customers on the tariff and to consider whether the tariff meets its objectives of job retention and the related economic benefits. If it does not, then the JRR will not be continued beyond its one-year term. Except as modified by this order, the Commission finds that it is reasonable for DEC to implement JRR and JRRR as proposed in the Stipulation and Pirro Settlement Exhibit 1.

The Company, as well as ratepayers, benefit from the retention of industrial jobs, and the load related to the retention of the industrial jobs. In addition to the testimony in this case, this fact is further justified by the Company's indication in Docket No. E-100, Sub 73 that it was considering funding all or a portion of a JRT and provided comments on the necessary requirements for measurement and verification under the scenario of a fully Company-funded JRT. To achieve just and reasonable rates, if the pilot program is extended to a second year, it is appropriate for the Company to contribute to the JRR at the same level as year one. Therefore, the Company's recovery should be reduced by the amount of $4.5 million if the Commission determines in the rider proceeding that the JRR pilot program should be extended to a second year.

The Commission, therefore, concludes that the proposed JRR, as modified by this Order, is in the public interest, is not discriminatory and is consistent with the Commission's holding that "approval of a JRT is a matter of sound ratemaking policy to address the undisputed decline in industrial sales in North Carolina." Order Adopting Guidelines for Job Retention Tariffs in Docket No. E-100, Sub 73, at 22. If the JRR is extended an additional year and at the end of the second year the Company determines there is still a need for the JRR, nothing in this order prevents the Company for filing for a new JRR based upon the economic circumstances at that time.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 65-68

The evidence supporting these findings of fact and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the record in Docket No. E-7 Sub 1110, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

In Docket No. E-7, Sub 1103, DEC requested to defer its costs of complying with the Coal Ash Management Act (CAMA) and the EPA's Coal Combustion Residual Rule (CCR Rule, collectively CAMA) and notified the Commission that it had established an Asset Retirement Obligation (ARO).

In its March 15, 2017 comments in Docket No. E-7, Sub 1103, the Public Staff supported the Company's deferral request, provided that ratemaking treatment for the deferred amount would be determined in the next base rate case:

> In this particular case, the Public Staff believes that the non-capital costs and depreciation expense related to compliance with state and federal requirements cited in the Companies' petition generally satisfy the criteria for deferral for regulatory accounting (but not necessarily ratemaking) purposes. First, they are adequately extraordinary in both type of expenditure and in magnitude to justify consideration for deferral. Second, the effect of not deferring the expenses on the Companies' respective earned returns on common equity would be significant.

Initial Comments of the Public Staff, at p. 6.

In the present docket, DEC witness McManeus noted that the Company had petitioned in Docket Nos. E-2, Sub 1103, and E-7, Sub 1110, for approval to defer certain costs incurred to comply with environmental requirements for Coal Combustion Residuals (CCR or coal ash). Tr. Vol. 6, p. 239. While various parties opposed recovery in rates of some of the coal ash costs, that is a separate issue from the deferral request. The deferral request was generally unopposed, and the Commission finds and concludes that deferral in a regulatory asset for previously incurred coal ash environmental costs is consistent with the Commission's criteria for deferrals and reasonable in the circumstances of this case.

In the present docket, Public Staff witness Maness indicated that the Public Staff continues to believe that prudently incurred CCR expenditures should be allowed to be deferred for regulatory accounting purposes. Witness Maness made several adjustments and with regard to the addition of a return on deferred coal ash expenditures from December 2017 through April 2018, DEC agreed with this adjustment (Tr. Vol. 6, p. 314), and it was not opposed by other witnesses. The Commission notes that new rates will not be effective by May 1, 2018, as might have been expected at the time of the filing of witness Maness' testimony; therefore, the Commission finds it appropriate and reasonable to extend the accrual of this return until the effective date of rates approved in this proceeding. Based on the foregoing, the Commission finds and concludes that a return based on the net-of-tax overall weighted cost of capital authorized in DEC's last general rate case should be added to the amount of deferred coal ash costs are approved in this Order for recovery in rates, and that the return should be applied through the effective date of the rates approved in this proceeding.

Additionally, as recommended by the Public Staff, the Commission concludes that use of the 2018 federal income tax rate of 21% is appropriate to calculate the 2018 portion of the carrying costs. With respect to Public Staff witness Maness' adjustment regarding mid-month cash-flow convention, DEC witness McManeus accepted this adjustment (Tr. Vol. 6, p. 314), and no other witness opposed it. The Commission finds and concludes that the mid-month convention for calculation of the return is reasonable and appropriate. Additionally, as recommended by the Public Staff, the Commission concludes that compounding of the carrying costs should take place at the beginning, rather than the end, of January of each year.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 69-72

The evidence supporting these findings and conclusions is contained in the Stipulation, the Company's verified Application and Form E-1, the testimony of the public witnesses, and the testimony and exhibits of the following expert witnesses: DEC witnesses Fountain, McManeus, Kerin, Wells, Wright, De May, Hager, and Doss; Public Staff witnesses Junis, Garrett, Moore, Lucas, Boswell, and Maness; AGO witness Wittliff; CUCA witness O'Donnell; and Sierra Club witness Quarles.

The public witness testimony and expert witness testimony and exhibits regarding DEC's CCR costs are voluminous. The Commission has carefully considered all of the evidence and the record as a whole. However, the Commission has not attempted to recount every statement of every witnesses. Rather, the following is a complete summary of the evidence.

Likewise, the Commission has read and fully considered the parties' post-hearing briefs. However, the Commission has not in this order expressly addressed every contention advanced or authority cited in the briefs.

Based upon the evidence addressed below and in the exercise of its expert judgment and discretion, the Commission determines that a management penalty of approximately $70 million should be assessed for DEC's mismanagement of its CCR activities undertaken through the end of the test year as extended for reasons set forth hereafter.

Coal-fired power plants have played a predominant role in electricity generation by DEC throughout its history, and the Company is dependent upon coal-fired generation today. With coal-fired generation comes a by-product – coal ash, also known as coal combustion residuals, or CCRs. At least since the 1950s, standard industry practice, particularly in the Southeastern United States, has been reliance on coal ash basins. Such basins were constructed and used at all of the Company's coal-fired generating units.

The United States Environmental Protection Agency (EPA) has studied CCRs and their proper management and handling since the 1980s, but the agency only began moving forward on comprehensive regulation of CCRs less than ten years ago. In 2010, the EPA issued proposed rules regarding CCRs. EPA's final rule – the Coal Combustion Residuals Rule (CCR Rule) – was promulgated on April 17, 2015. North Carolina also enacted specific statutory requirements for coal ash management in CAMA, which became effective in 2014 and was amended in 2016. The CCR Rule and CAMA introduced new requirements for the management of coal ash. DEC, of course, must comply with these new requirements, which mandate closure of the Company's coal ash basins. Mandated closure triggers Generally Accepted Accounting Principles (GAAP) provisions relating to the retirement of long-lived tangible assets, and specifically triggers the requirement that the Company account for compliance costs through ARO accounting. The Company, as required by GAAP, established an ARO with respect to its coal ash basins, and, in accordance with the Commission's orders in Docket No. E-7, Sub 723, deferred the impacts of its GAAP-mandated ARO accounting. The Company now seeks recovery of the coal ash basin closure costs incurred to date in connection with CCR Rule and/or CAMA compliance, along with such costs it anticipates will be incurred annually on an ongoing basis. The Company's proposal has three component parts:

- First, DEC seeks recovery of the actual coal ash basin closure costs it incurred from January 1, 2015 through December 31, 2017. On a North Carolina retail jurisdiction basis, these costs amount to $566.8 million.[52] McManeus Rebuttal Ex. 3, pp. 36-37. The Company proposes further that, rather than recovering 100% of these already incurred costs immediately, it recover them over a five-year amortization period, and it seeks a return on the unamortized balance.

- Second, DEC seeks to recover on an ongoing basis $201.3 million per year in annual coal ash basin closure spend. This amount is based upon the NC retail jurisdiction portion of the test year (2016) coal ash basin closure expense incurred by the Company.
- Third, DEC seeks permission to establish a regulatory asset/liability and defer to this account the NC retail portion of annual costs that are over or under the costs established in connection with the Company's request that it be permitted to recover in rates on an ongoing basis its actual test year coal ash basin closure costs – i.e., the amount over or under $201.3 million, if the Company's proposal as detailed above is approved by the Commission. In addition, the costs incurred from January 1, 2018 through the date new rates set in this proceeding are effective would also be deferred to this account. The deferred amounts (including a return) would be brought into rates and recovered through future rate cases.

The Commission, as it has in prior rate orders, provides a review of the applicable legal principles, to provide a framework for the application of those principles to the facts of this particular case. See, e.g., 2013 DEC Rate Order, pp. 23-28 (in Duke Energy Carolinas 2013 Rate Case, Commission provided an extensive review of the "governing principles" regarding rate of return). For purposes of assessing the Company's coal ash basin closure cost recovery proposal, the applicable principles include (1) the general cost recovery framework and the role of the revenue requirement in that framework; (2) principles underlying "reasonable and prudent" costs; (3) principles underlying the concept of "used and useful," and (4) a discussion of the burden of proof, and, in particular, presumptions and the distinction between the burden of production (borne by Intervenors) and the ultimate burden of persuasion (borne by the Company).

In the recently-decided DEP rate case (Docket No. E-2, Sub 1142, the 2018 DEP Rate Case, or 2018 DEP Case), the Commission's decision summarized cost recovery based upon these principles, and found that for cost recovery the utility must prove that the costs it seeks to recover are "(1) 'known and measurable'; (2) 'reasonable and prudent'; and (3) 'used and useful' in the provision of service to customers." 2018 DEP Rate Order, p. 143. The same standard applies in this case.

The arguments raised by Intervenors in this docket challenge the inclusion of the Company's coal ash basin closure costs in rates because the costs are not "reasonable and prudent" and "used and useful," or on the theory that cost recovery should be shared by both the shareholders and ratepayers.

[52] This amount excludes any fines, penalties and other unrecoverable costs incurred by the Company. See Tr. Vol. 6, p. 259.

Summary of the Evidence

A. Company Direct Case Overview and Costs Sought for Recovery

In his direct testimony, Company witness Fountain testified that DEC is requesting recovery of ash basin closure compliance costs incurred in the period from January 1, 2015 through November 30, 2017. Witness Fountain explained that the Company has removed costs related to its response to the Dan River release and is not requesting their recovery for them. Tr. Vol. 6, p. 174. Witness Fountain also testified on direct that, based on actual coal ash expenses incurred during the 2016 test year, DEC is seeking recovery of ongoing ash basin closure compliance spend of $201 million per year, with any difference from future spend being deferred until a future base rate case. He stated that including this revenue requirement will provide a measure of predictability to customers of future coal ash expense rate drivers. Id. at 174.

Company witness McManeus testified that Adjustment No. 18 to the Company's operating revenues and expenses amortizes the actual deferred costs incurred through December 31, 2017, in connection with compliance with federal and state environmental requirements related to CCRs, pursuant to DEC's petition in Docket Nos. E-2, Sub 1103 and E-7, Sub 1110 for authority to defer such costs in a regulatory asset account, over a five-year period. She explained that while the costs to comply with CAMA and the CCR Rule are largely duplicative, the Company has determined a small portion of the costs to be specific to CAMA, unique to North Carolina and appropriate for direct assignment to North Carolina. She stated that in the deferral calculation, for CAMA-specific costs, the adjustment separates out the portion allocable to the wholesale jurisdiction and directly assigns the retail portion to North Carolina retail. She stated that these costs were based on actuals at the end of the test period, updated through November 30, 2017.[53] The Company proposes to defer these costs over a five-year period and to earn a net of tax return on the unamortized balance. Witness McManeus testified that the expected deferred balance, based on total system spend on these costs during this period, plus applying allocation factors and incorporating the return on the deferred costs, is $524.0 million.[54] Witness McManeus clarified the Company seeks no recovery for fines, penalties, or costs of which DEC has agreed to forego in the deferral. Tr. Vol. 6, pp. 259-60, 279-80, 288-89, 297, 343.

Witness McManeus testified that Adjustment 19 increases O&M to reflect the expected ongoing annual level of expenses DEC will incur in connection with coal ash compliance costs represents the amount in ongoing annual coal ash basin closure expense (sometimes referred to in this Order as "ongoing compliance costs"). She explained that this number – $201.3 million on a North Carolina retail basis – is based upon actual test year (2016) spend, and stated that the Company is also requesting

[53] These costs were later updated to actual costs through December 31, 2017, and the deferred balance including return computed as of April 30, 2018. McManeus Rebuttal Ex. 3, pp. 36-37.

[54] This amount has been adjusted to $566.8 million based on the estimated deferral balance at April 30, 2018. McManeus Rebuttal Ex. 3, pp. 36-37.

permission to establish a regulatory asset/liability and defer to this account the North Carolina retail portion of annual costs over or under the amount established in this proceeding. She explained that this will ensure that the Company only recovers from customers its actual level of spending related to coal ash. She also clarified that no fines, penalties, or costs of which DEC has agreed to forego recovery are included in this adjustment. Tr. Vol. 6, pp. 260-61, 279-80, 288-89.

B. Company Direct Case: Coal Ash Overview

Company witness Kerin described his management role with the Ash Basin Strategic Action Team (ABSAT), the umbrella organization created for Duke Energy companies to address the laws, regulations, and orders concerning the management of CCRs. Witness Kerin discussed how, during his work on the ABSAT team, he spent approximately 3,000 hours working exclusively on CCR issues, familiarizing himself with state and federal regulations dealing with CCR and historical industry practices and standards used to comply with such regulations. He described how he interviewed legacy employees who worked at, and with, coal combustion generating units and CCR handling sites, and reviewed historical company documents dealing with those facilities and sites in order to gain an understanding of how CCR handling standards inside and outside of the Company developed over time. Witness Kerin also described how he toured and inspected every CCR basin in Duke Energy's North and South Carolina jurisdictions, as well as CCR sites at Duke's Midwest sites, Dominion, AEP, and TVA. He detailed how he developed CCR evaluations for Duke Energy's CCR sites, and an industry peer group to discuss CCR issues generally, which continues to meet semi-annually. Witness Kerin concluded that during his time on the ABSAT team, he gained an understanding and knowledge of coal ash management practices at utilities across the country. Tr. Vol. 14, pp. 96-97.

Witness Kerin provided a detailed discussion of DEC's coal ash management history and practices and the new obligations imposed on the Company by the CCR Rule and CAMA. He explained that CCRs are by-products produced from the electricity production process lifecycle – the burning of coal – at coal-fired generation plants and include fly ash, bottom ash, boiler slag, and flue gas desulfurization (FGD) material. He stated that environmental regulations related to CCR management have evolved significantly over time, affecting how the Company has operated its coal-fired plants in compliance with those obligations. He maintained that at each step in the environmental regulatory evolution process, DEC was in line with industry standards and maintained that DEC reasonably and prudently managed CCRs and its coal ash basins. He explained that since its last rate case, DEC has become subject to both federal and state regulations that require it to take significant action to close its ash basins. Tr. Vol. 14, pp. 99-112.

Witness Kerin testified that since the early 1900s, DEC has disposed of CCRs in compliance with then current regulations and industry practices. Until the 1950s, CCRs were either emitted through, in the case of fly ash, smokestacks or, in the case of bottom ash, manually removed the ash from boilers and stored it in landfills. Since that time, the industry transitioned to a water sluice to remove ash from boilers, and to clean the electrostatic precipitators, preventing ash from being emitted through the smokestacks. This effluent, as well as FGD blowdown, was then diverted to ash basins, of which DEC has 17 in the Carolinas. In other words, in many cases, ash basins were actually created or relied upon to effectuate prior environmental regulations. In the mid-1970s, the enactment of the Clean Air Act and its subsequent amendment in the 1990s required electric utilities to capture more CCRs through the use of electrostatic precipitators (ESP) or bag houses and FGD blowdown. Tr. Vol. 14, pp. 99-112.

Witness Kerin provided a detailed history of coal ash regulation. He testified that the Clean Water Act of 1972 and the subsequent creation of the National Pollutant Discharge Elimination System (NPDES) permitting system, made wet ash handling and ash basins the primary lawful and effective way to meet CCR needs and environmental requirements from 1974 until 2015. Tr. Vol. 14, pp. 100, 106-09.

Witness Kerin testified that, in June 2010, the EPA proposed national minimum criteria to regulate the disposal of CCRs and the operation and closure of active CCR landfills and existing and inactive CCR surface impoundments. He stated that, approximately five years later in April 2015, EPA published the final CCR Rule in the Federal Register. He explained that the CCR Rule established national minimum criteria for CCR landfills and surface impoundments, which result in different impacts at each CCR unit, depending on site-specific factors, and testified to the exact nature of those criteria. He stated that the CCR Rule also contains requirements for how and when CCR basins must be closed, and that it provides for closure either by cap-in-place or removal of the ash. He noted that as stated in the CCR Rule, the EPA considers CCRs to be a non-hazardous solid waste. In 2014, North Carolina enacted CAMA, which requires that all ash basins in the State be closed, either through excavation or via the cap-in-place method. He explained further that CAMA requires closure of all ash basins in North Carolina, with the closure option (excavate or cap-in-place) and deadline driven by a prioritization risk ranking classification process. Witness Kerin noted that, in many respects, CAMA mirrors the federal CCR Rule. He stated that all of DEC's ash basins must be closed under one or both of these programs. Tr. Vol. 14, pp. 100, 115-26.

He also stated that the Company has begun the process of closing, or submitting plans to close, its ash basins in accordance with the program with the most limiting requirements. Tr. Vol. 14, p. 100. Witness Kerin also testified that coal-powered electric generation has since ceased at four of the eight coal-fired DEC generating facilities with ash basins, including the Dan River, Buck, Riverbend, and W.S. Lee plants. Id. at 103.

Witness Kerin also noted that in addition to the CCR Rule and CAMA, DEC is also subject to other CCR-related obligations that result from state environmental regulatory oversight under existing rules and regulations. For DEC, in South Carolina, there is one Consent Agreement with the South Carolina Department of Health and Environment (SCDHEC) applicable to ash management at the W.S. Lee plant. The W.S. Lee Consent Agreement, between DEC and SCDHEC, requires ash excavation of the Inactive Ash Basin, the Ash Fill Area, and any other areas where ash may have potentially migrated from these sites. Tr. Vol. 14, p. 127.

Witness Kerin testified that the CCR Compliance Requirements—CAMA, the CCR Rule, and other consent and/or settlement agreements and orders concerning CCR management and disposal—represent new regulatory requirements that have significantly changed the operation and life cycle of the on-site ash basins and landfills. Id. at 115. He noted that there is a great deal of duplication and interaction between federal rule, state law and agency action and that many of the actions Duke Energy will take will serve multiple compliance purposes. He explained that many actions and draft rules applicable to many utilities, not just Duke Energy, were already being developed prior to 2014, and that the Company is now in another wave of evolution in environmental regulation pertaining to ash. He stated that in response to these new requirements addressing CCR disposal activities, the Company is adding dry fly ash, bottom ash, and FGD blowdown handling systems to operating coal-fired plants that are not already so equipped. He also stated that the Company is modifying all active and decommissioned plants to divert storm water and low-volume wastewater away from the basins. He testified that, accordingly, the Company is requesting recovery of the incremental compliance costs related to coal ash pond closures incurred starting in 2015 through November 30, 2017, and recovery of ongoing compliance costs. He maintained that both these incurred and ongoing compliance costs are reasonable, prudent, and cost effective given the individual facts and circumstances at each power plant and ash basin site at issue. He maintained further that each of the Company's historical and ongoing CCR compliance costs is reasonable, prudent, and cost effective given the individual facts and circumstances at each power plant and ash basin site at issue. Tr. Vol. 14, pp. 100-01.

Witness Kerin stated that ash removal has been initiated at several DEC stations, including the Dan River and Riverbend Plants. He stated that excavation plans were developed to systematically prepare for executing this work, including the identification of any necessary permits and approvals. These excavation plans were submitted to the applicable state regulatory body, SCDHEC or DEQ, prior to beginning ash excavations. As the CCR Rule and CAMA lead to ash basin closure, preparations are required to transition the coal-fired generating sites for this outcome. Operating coal-fired power plants in the Carolinas require plant modifications to fully transition to dry ash handling in order to cease sluice flow to the ash basins. All coal-fired power plants, even those retired, require some level of modification to cease all flows to the ash basins, such as storm water or low volume waste water, and may require construction of a new retention pond. These modification activities are planned and are now being executed. Tr. Vol. 14, p. 132.

Witness Kerin described the closure plans and site analysis and removal plans developed by Duke Energy to physically close the ash basins, noting that these plans are technically informed by the structural stability of the impoundments, the potential for adverse impacts from external events such as 100-year floods, the groundwater and/or surface water impacts identified in the Closure Study Analysis, and the groundwater corrective actions required in the Corrective Action Plans. Ash basins can be closed by excavation, with the ash permanently stored in a CCR landfill or used in a beneficial way such as a structural fill or for cementitious purposes. Ash basins can also be closed by capping the CCR in place. Tr. Vol. 14, pp. 132-33.

Witness Kerin also maintained that the Company's CAMA closure plans will meet the national standards set forth by the CCR Rule as well as the more specific requirements determined by the North Carolina Department of Environmental Quality (DEQ) under the CAMA regulatory process. He explained that the state-mandated closure plans are reviewed and approved by SCDHEC in South Carolina and DEQ in North Carolina. During this review and approval process, these state regulatory agencies could impose additional restrictions, limitations, requirements, and/or actions to close the ash basins. Other specific compliance plans will be developed and implemented to meet the various requirements and timelines of CAMA and the CCR Rule, such as the fugitive dust control plans, which were required under Section 257.80 of the CCR Rule by October 19, 2015. As a second example, run-on and run-off control system plans were developed and implemented by October 19, 2016, for CCR landfills pursuant to Section 257.81 of the CCR Rule. Compliance plans will continue to be developed and implemented as required by the CCR Rule and CAMA. Tr. Vol. 14, p. 133.

Company witness Kerin testified that in Exhibits 10 and 11 to his testimony, he broke the ash pond closure costs already incurred or expected to be incurred prior to November 30, 2017, down into their core components and described the plants to which these costs apply. In detailing these costs, he also provided narrative summaries as to why, in his view, these costs were incurred and why the compliance actions which led to those costs were the most reasonable and cost-effective options given the applicable facts and circumstances. He maintained that these exhibits, coupled with the balance of his testimony and exhibits, demonstrate that these costs are reasonable and prudent. Tr. Vol. 14, p. 135.

Company witness Kerin maintained that DEC's historical handling of CCRs was reasonable, prudent, and consistent with industry standards over time. This demonstrates that nothing that DEC has done historically is causing the Company to incur any unjustified costs today to comply with post-2015 CCR regulations. Tr. Vol. 14, p. 135. Company witness Kerin explained that, in the preamble to the CCR Rule, EPA details that in 2012 alone, over 470 coal-fired electric generating facilities burned over 800 million tons of coal, generating approximately 110 million tons of CCRs in 47 states and Puerto Rico. In 2012, approximately 40% of the CCRs generated were beneficially used, with the remaining 60% disposed in CCR surface impoundments. Of that 60%, approximately 80% was stored in on-site basins and landfills. Across the United States, CCR disposal currently occurs at over 310 active on-site landfills, averaging over 120 acres in size with an average depth of 40 feet, and at over 375 active on-site surface impoundments. Stated differently, according to witness Kerin, the Company is re-using (selling) and storing CCRs in the same manner and at approximately the same percentages as the coal-fired utility industry's national averages. Duke Energy's practices have been and continue to be consistent with those of the industry. Similar to the industry, DEC has on-site CCR landfills that are actively receiving production fly ash, and some bottom ash, at specific coal-fired generating sites, including the Allen, Belews Creek, Cliffside, and Marshall Plants in the Carolinas. Also similar to the industry, DEC has active ash basins still receiving bottom ash, and some fly ash, at specific coal-fired generating sites, including the Allen, Belews Creek, Cliffside, and Marshall Plants in the Carolinas. Witness Kerin maintained that the ash handling practices for ash basins and ash landfills in the Carolinas are consistent with the applicable regulatory requirements that were in effect during the history of these CCR units. Tr. Vol. 14, pp. 113-14.

Witness Kerin also maintained that DEC's CCR storage and handling practices are consistent with the practices of other Duke Energy affiliates and Duke Energy peer utilities. He explained that the Company's CCR storage and handling practices are consistent across the Duke Energy fleet, including coal generation located in Florida and in the Midwest. Duke Energy as it currently exists today has been formed over the years through the mergers of several utilities with independently operated coal fired generation, including the Cinergy Corporation in 2006 and Progress Energy, Inc. in 2012. Indeed, going further back in time, Progress Energy, Inc. was created in 2000 from the merger of legacy utilities CP&L and Florida Power Corporation (FPC). Similarly, Cinergy Corporation was created in 1994 by the merger of legacy utilities Public Service Indiana (PSI) and Cincinnati Gas & Electric Company (CG&E). Yet, the historical and current CCR handling and use of CCR basins is consistent across all of these legacy companies that make up Duke Energy Corporation today, and consistent with the industry. Tr. Vol. 14, p. 114.

At the hearing, in response to questions from counsel for the Sierra Club regarding reports on ash disposal from the 1970s and 1980s, witness Kerin clarified that DEC did not build any new basins after 1982, when the last basin was constructed at Buck, and that any other disposal areas constructed by the Company would have been undertaken pursuant to permit by the DEQ or its predecessor. Tr. Vol. 14, pp. 180-84. He also testified that, in his opinion, there would not be increased cost associated with the schedule of activities contained in the draft Special Order by Consent (SOC) resolving a DEQ Notice of Violation with regard to the Allen, Marshall, and Cliffside plants that would not otherwise have been incurred, and clarified that cap-in-place costs are based on acreage size, not volume of ash in the basin. Id. at 213-18.

In his direct testimony, Company witness Wright noted that coal ash use and disposal has been studied by the EPA since the mid-1980s. After several studies and some limited regulatory standards, on May 22, 2000, the EPA determined the need to regulate coal combustion wastes under Subtitle D of the Resource Conservation and Recovery Act (RCRA). He noted that these types of expenses have been routinely recovered as a cost of service and included in rate cases including the reasonable costs associated with operating, maintaining and upgrading environmental equipment. The cost recovery for these rate-based environmental costs also usually included a return. Tr. Vol. 12, pp. 130-31.

C. Company Direct: Cost Recovery Overview

Witness Wright also testified that in part as a response to an accident at a surface impoundment at Tennessee Valley Authority's (TVA) Kingston Fossil Plant in Harriman, Tennessee, the EPA published in the Federal Register proposed new coal ash disposal regulations for CCRs. The proposed regulations specifically referenced the TVA incident as a major reason for the proposed rule, and discussed several other coal ash incidents that led to the promulgation of the rule. Witness Wright maintained that, because the EPA's proposed rule's publication date precedes the February 2, 2014 coal ash release accident at the Dan River Steam Station (Dan River), the Dan River accident was not mentioned in the EPA's proposed rule, nor could it have been, as a reason for establishing the rule. He also noted that EPA's finalized CCR Rule, signed on December 19, 2014 and published in the Federal Register (FR) on April 17, 2015, did reference the Dan River accident, but it did not indicate that the accident modified the proposed rule. Tr. Vol. 12, pp. 131-32.

Witness Wright further explained that in August 2014, after the EPA's proposed coal ash regulations were published but prior to their finalization, the State of North Carolina adopted CAMA. He noted that while EPA and CAMA rules are similar in many respects, "largely duplicative," DEC must ensure that its coal ash disposal methods meet the standards established in both regulations as well as any other state agency requirements. Tr. Vol. 12, p. 132.

Witness Wright maintained that recoverable costs, as they relate to electric utility expenditures in North Carolina, are costs that are reasonable and that are prudently incurred in the provision of safe, reliable electric service to a utility's customers. He argued that N.C. Gen. Stat. § 62-133(b) embodies this principle. He maintained that because environmental compliance costs are a necessary cost of providing electric service, these types of costs – and a return on those costs if deferred over time – are recoverable in rates. He also maintained that environmental compliance costs are similar to other costs that a utility might spend in producing and delivering power. He asserted that the Company incurs costs in compliance with environmental laws and regulations, similar to other costs necessary for the generation of electric power, and that these coal ash disposal costs are like nuclear decommissioning costs or coal plant retirement costs which have long been deemed recoverable for utilities across the country, including DEC. Tr. Vol. 12, p. 123.

Witness Wright noted that the Commission has allowed the recovery of costs related to environmental expenditures. Citing to witness Kerin's lengthy discussion of the numerous investments the Company has made over time in compliance with historical coal ash and other environmental regulations, he asserted that in his experience these types of costs, including the reasonable costs associated with operating, maintaining and upgrading environmental equipment, plus a return, have been routinely recovered as a cost of service through general rate cases, whether as capital or ongoing operation and maintenance expense or some combination thereof. Tr. Vol. 12, pp. 127-29.

Witness Wright testified further that utilities are not allowed to recover environmental fines or penalties, or costs incurred from the actions causing such penalties. He stated his understanding that none have been requested in this case. He also asserted that it is important, however, to make sure that the costs underlying or directly causing such fines or penalties be separated from prudently incurred, ongoing costs. For example, he offered, if a generating plant received a fine, that fine should not be recoverable. The fact that a fine was given, however, does not mean that the ongoing, prudently-incurred costs necessary to produce generation should be disallowed. Tr. Vol.12, p. 130.

Witness Wright further asserted that the new federal coal ash standards did not result from the Dan River spill. He noted that the final rule only mentions the Dan River accident, and that there is no clear evidence in the final rule that the Dan River accident changed or modified the EPA's proposed rule. He asserted that both the proposed rule and the final rule addressed the need for imposing corrective action at inactive facilities, and asserted that in promulgating the CCR Rule, the EPA cited hundreds of potential risks or incidents with ash ponds similar to Dan River that, in part, led to the adoption of the Rule. Based on this analysis along with the timing of the CCR Rule, he opined that the Dan River accident did not change the CCR regulations, although it probably added support for the EPA's proposals. Tr. Vol. 12, pp. 132-34.

Witness Wright also maintained that, in terms of timing, the new state CAMA coal ash standards did result from the Dan River spill, but in terms of the substance of the standards adopted there is not necessarily a connection. He opined that the Dan River spill helped prompt the North Carolina General Assembly to examine the State's and national coal ash disposal policies and regulations, and that out of that legislative investigation came CAMA. He noted that some four years prior to Dan River, the EPA had proposed and was close to finalizing its new CCR regulations, which in his opinion helped inform the State's legislative leaders regarding the language contained in CAMA. He noted that the proposed CCR regulation also strongly encouraged the states to adopt at least the federal minimum criteria in their solid waste management plans. Therefore, he concluded, that the North Carolina Legislature and/or the State's DEQ would likely have taken steps to adopt coal ash regulations shortly after the CCR Rule was finalized in 2015. He concluded that the timing of CAMA was influenced by the Dan River accident, but also expressed his belief that, even without the Dan River accident, the State would likely have adopted some new coal ash disposal standards similar to CAMA in the 2015 timeframe in response to the CCR rules. He stated that, regardless, the Company must comply with both the federal and state coal ash disposal standards. Tr. Vol. 12, pp. 134-36.

In his direct testimony, Company witness Wright testified that, in his opinion, the coal ash disposal costs that DEC seeks to recover in this case are "used and useful" utility cost. Tr. Vol. 12, p. 144. He explained that DEC's coal ash disposal sites have always been used and useful as part of the coal-fired generation production process. He noted that N.C. Gen. Stat. § 62-133(b)(1) provides that, in setting utility rates, the Commission must "ascertain the reasonable original cost of the public utility's property used and useful, or to be used and useful within a reasonable time after the test period, in providing the service rendered to the public within the State, minus accumulated depreciation, and plus the reasonable cost of the investment in construction work in progress." Id. He testified that, therefore, to be recoverable and/or included in rate base, the cost must be both reasonable and incurred for property that is used and useful in providing service to customers. He stated that the Company has historically spent dollars in order to comply with the coal ash disposal regulations in effect at the time, and these dollars were a necessary expenditure related to used and useful utility costs made in the provision of electric service at the time. The Company was, and continues to be, obligated to meet the needs of its customers. This obligation to serve requires the disposal of coal ash subject to the disposal standards at the time, thereby rendering the disposal sites for this coal ash, for which costs DEC seeks recovery in this case, "used and useful" in providing electric service. Id. at 144-45. He stated that this is supported by the Commission's conclusions in the 2016 Dominion rate case, where the Commission determined that because current CCR repositories are and have served their purpose of storing CCRs for many years, they have been used and useful for ratepayers, and that such storage facilities will continue to be used and useful until the CCRs are moved to a permanent repository, or they are capped and closed. Id. at 145-46.

Witness Wright also noted with respect to the Commission's Order Approving Rate Increase and Cost Deferrals and Revising PJM Regulatory Conditions in Docket No. E-22, Sub 532 (Dec. 22, 2016) (2016 DNCP Rate Order) that, in that case, the Commission addressed the exact issue of the recovery of coal ash disposal costs that is at issue in this proceeding. In addition to the decision that prior coal ash disposal assets were used and useful, he noted that in that order the Commission and Public Staff concluded that Dominion's historical response to coal ash disposal was consistent with industry practice at the time and that these costs were reasonable and prudent. Second, they found that Dominion's test year coal ash disposal expenses incurred in compliance with the newer coal ash disposal regulations were likewise reasonable and prudent. Finally, he noted that, similar to what DEC is requesting in this rate case, the 2016 DNCP Rate Order also allows Dominion to establish an ARO to defer additional coal ash disposal cost and for the recovery of those costs to be adjudicated in a future proceeding. Tr. Vol. 12, pp. 146-47.

D. The Positions of Intervenor Parties other than the Public Staff

AGO witness Wittliff maintained that the Dan River ash release was largely responsible for the development of CAMA in its present form, which he said accelerated remediation and closures and narrowed the field of removal and closure options. Tr. Vol. 11, pp. 239, 248-50, 272. He claimed that the plea agreements into which the Company has entered evidence harm to the environment caused by DEC's criminal negligence. Id. at 239-41, 265-67, 272-73. He also claimed that the Company's actions and inactions resulted in environmental harm and the incurrence of compliance costs that could have been significantly lower or possibly even avoided. Id. at 274-75. He asserted that, by not building new lined surface impoundments when it was "obvious" that additional impoundments were needed and would better protect the environment, the Company delayed and avoided potential exposure to requirements for more rigorous environmental controls on the new impoundments. Id. at 255. He questioned the Company's diligence with respect to managing dam safety, contended that the Company did not comply with the requirements of its ash basin permits at Dan River and Riverbend, and asserted issues of vegetation control and stability of impoundments at other facilities. Id. at 255-63, 273-74. He also claimed that the Company's 10-K filings with the Securities and Exchange Commission (SEC) show Duke Energy's awareness of trends in coal ash management and regulation towards lined impoundments. Id. at 236-38. Witness Wittliff further questioned Company witness Kerin's expertise with regard to coal ash issues and claimed that the Company's coal ash handling practices were not consistent with industry. Id. at 268-69.

At the hearing, in response to questions by counsel for the Company, witness Wittliff admitted that, while his testimony stated that he would support a Commission finding that the coal ash costs incurred by DEC were unreasonable and imprudent, his actual position is that the Company should be able to recover its costs to comply with the CCR Rule, but nothing more. Tr. Vol. 11, pp. 279-81. However, in its post hearing brief the AGO, on whose behalf witness Wittliff testified, maintained that all of DEC's 2015-2017 CCR remediation costs should be disallowed. Witness Wittliff stated that costs incurred by the Company to comply with the CCR Rule are reasonable and prudent. Id. at 282-83. He admitted that he did not identify any specific costs that could have been lower or should be disallowed. Id. at pp. 287-89. In response to questions regarding environmental compliance issues at electric power stations at which he had worked over the course of his career, witness Wittliff testified that he was not in a position at those times to say what those companies should or should not have done with respect to environmental compliance, but that he is in such a position now with respect to DEC, to say what should have happened with the Company's previous coal ash management. Tr. Vol. 11, p. 289 – Tr. Vol. 12, pp. 13-24.

CUCA witness O'Donnell opined that DEC should only recover costs to comply with the CCR Rule, not any costs under CAMA that exceed CCR Rule compliance costs, based on his contention that Duke Energy caused CAMA. Tr. Vol. 18, pp. 59-60. Witness O'Donnell purported to compare the DEC coal ash ARO to what he termed similar coal ash AROs of utilities across the United States. He concluded that the Company's ARO coal ash costs are among the highest in the nation, and contended that the only discernable difference between the Duke Utilities and the other utilities in his comparison was CAMA, which he asserted was prompted by the Dan River spill. He stated that DEC did not provide a similar financial analysis for this case. Id. at 56, 61-66. He asserted that there is no evidence to suggest that Duke's coal ash situation is significantly different from that of utilities across the country or from that of utilities in neighboring states. He claimed the Company failed to provide any evidence to counter his argument that its mismanagement led to excessive costs associated with its coal ash cleanup, and that because the Company chose not to dissect his analysis "bit by bit," that gives his evidence more credence. Id. at 66.

Sierra Club witness Quarles evaluated the methods DEC has proposed to close existing coal ash ponds at the Allen and Marshall plants and opined as to environmental conditions that may be associated with capping those ponds in place. He asserted that he evaluated site conditions at each location and the likelihood that DEC will be able to meet closure performance standards in the CCR Rule if it opts for cap-in-place closure. He also asserted that continued storage of coal ash at Allen and Marshall poses significant environmental risks. He stated that the coal-fired power plant industry recognized in at least the mid-1970s that disposal of CCRs into unlined disposal units and within close proximity to groundwater was risky, and that construction of unlined disposal units after that time was unreasonable. He claimed it would have been consistent with industry practice at the time for DEC to close and remediate leaking impoundments and construct new, lined dry landfills. He asserted that the Company built new unlined disposal areas at Allen and Marshall, and that lined landfills and surface impoundments were commonplace and more cost effective than building unlined surface impoundments since the mid-1970s. Tr. Vol. 6, pp. 19-118, 120-22.

Witness Quarles stated that the unlined basins at these plants were constructed over named and unnamed stream valleys, with wastes submerged in groundwater, and groundwater flows into those basins from topographically higher elevations and will come in contact with submerged coal ash. He also stated that there are documented impacts to groundwater at these basins and that a cap will not prevent lateral inflow of groundwater from adjacent areas. He concluded that closure in place at these basins would allow continued contamination of downgradient groundwater and violate the technical standards of the CCR Rule, and that removal of coal ash from the Company's ash basins would reduce the concentrations and extent of this contamination. Lastly, witness Quarles stated that DEC's plan for closure-in-place is well documented by the coal power trade industry association as an inappropriate groundwater corrective action where CCRs are submerged in groundwater like at Allen and Marshall. Tr. Vol. 6, pp. 19-118, 122-24.

At the hearing, Witness Quarles did not dispute on cross examination by Company counsel that the 1988 Report to Congress stated that only about 25% of all facilities had liners to reduce offsite mitigation of leachate, that only 40% of generating units built since 1975 had liners, that only 15% had leachate collection systems, only one-third had groundwater monitoring systems and that such systems were more common at newer facilities, that coal combustion waste streams generally do not exhibit hazardous characteristics, and that EPA's tentative conclusion was that current waste management practices appear to be adequate for protecting human health and the environment. Witness Quarles also confirmed that he did not conduct a site-by-site engineering analysis of the cost to the Company to close and remediate leaking impoundments and construct new, lined dry landfills. Tr. Vol. 6, pp. 143-45. In response to questions by the Commission he admitted that he has not raised the concerns he raised in this proceeding regarding cap-in-place at Allen and Marshall with DEQ. Tr. Vol. 6, pp. 149-50.

In its post-hearing Brief, the AGO contends that ratepayers should not be forced to cover costs caused by DEC's historic imprudence in managing its coal ash basins. The AGO argues that the Commission needs to consider several factors when determining whether the costs incurred are recoverable in rates. The AGO outlines them as follows: 1- The first is DEC's history of imprudence; 2- DEC's costs must be reviewed in detail to evaluate whether and to what extent they are for property that is "used and useful" and are recoverable in ratebase; 3- DEC has insurance to cover a large portion of the coal ash remediation costs it seeks from ratepayers, and these insurance proceeds should be taken into account; 4- DEC's request for cost recovery relies on a petition for an accounting order allowing deferral of the costs that is untimely, unreasonable, and unjustified as a basis for retroactive recovery of expenditures that DEC incurred in 2015 and 2016; and 5- DEC's claim that it is "entitled" to the recovery of coal ash costs from prior periods if it proves the costs are "known and measureable," "reasonable and prudent," and "used and useful" is not consistent with the statutory ratemaking regime, in which rates are established and become effective prospectively in order to allow—but not guarantee—the opportunity for cost recovery, and the rates are presumed to be just and reasonable until new rates are established by the Commission.

The AGO disagrees with this Commission using a 1988 DEP case in its recent decision in Docket No. E-2 Sub 1142, regarding Duke's burden of proof of prudent and reasonable costs. The AGO states that under the Commission's "prudence framework" in the DEP Order recently issued, a utility's costs are presumed to be reasonable and prudent unless challenged, and the challenges presented must show three things: "(1) they must identify specific and discrete instances of imprudence; (2) demonstrate the existence of prudent alternatives; and (3) quantify the effects by calculating imprudently incurred costs." In re Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service In North Carolina, Docket No. E-2, Sub 1142, Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase, at 196 (Feb. 23, 2018)("2018 DEP Order")(citing the 1988 DEP Rate Order at 15) The AGO contends that this framework essentially puts the burden of proof on Intervenors. The AGO argues that it should be up to DEC to prove that some or all of the detailed costs are not attributable to its poor history of operations.

The AGO argues that evidence that the Company was noncompliant with regulatory requirements shows its imprudence, and cites Commissioner Brown-Bland's dissent to the 2018 DEP Order, indicating that violations of statutes that have the purpose of protecting the public from harm to life or safety constitute negligence per se. See Bell v. Page, 271 N.C. 396, 156 S.E.2d 711 (1967); Hampton v. Spindale, 210 N.C. 546, 187 S.E. 775 (1936). The AGO contends that DEC's five criminal convictions should be conclusive evidence of imprudence.

The AGO states that the Commission may consider an agency's standards or determinations when making its own determination about the prudence and reasonableness of coal ash activities, but cannot simply substitute another agency's determination or standards for its own. See State ex rel. Utils. Comm'n v. Carolina Water Service of North Carolina v. Public Staff, 335 N.C. 493, 503, 439 S.E.2d 127, 132 (1994).

The AGO states that coal has been utilized for many decades and beginning in approximately 1950, DEC, like many utilities, used unlined earthen impoundments to deposit its CCRs. The AGO states that in the 1970s, the United States Department of Energy directed that research be done on coal ash residuals and that the research revealed that there was a "growing awareness that the discarded wastes from coal combustion are a serious potential source of surface and ground water contamination" and that the wastes "have the potential for causing great environmental damage if not properly handled." 1979 Los Alamos Report, Tr. Ex. Vol. 12, pp. 189-204. In 1988, the

EPA, in its Report to Congress on the topic of "Wastes from the Combustion of Coal by Electric Utility Power Plants," voiced concerns over the "substantial quantities of wastes" produced by electric utility power plants and concurred with the Los Alamos Report that "[t]he primary concern regarding the disposal of wastes from coal-fired power plants is the potential for waste leachate to cause ground-water contamination" from the potentially toxic metals in the ash due to the fact that "[m]ost utility waste management facilities were not designed to provide a high level of protection against leaching." 1988 EPA Report to Congress, Tr. Ex. Vol. 12, p. 228.

The AGO contends that before the North Carolina General Assembly passed CAMA, DEC's coal ash activities were governed by three important laws: North Carolina's Dam Safety Act, the federal Clean Water Act, and North Carolina's 2L Groundwater rules and that DEC violated all of these laws and standards.

First, the AGO alleges that DEC violated dam safety standards. The AGO states that during the five-year dam safety inspections between 1996 and 2009, all seven of the facilities were cited for issues regarding seeps. Tr. Vol. 11, p. 259. Between 1996 and 2009, the five-year dam safety inspectors also expressed concerns regarding stability issues at the Allen, Dan River, Marshall, Cliffside, and Riverbend Steam Stations. Tr. Vol. 11, pp. 261-262. After the TVA incident, the dams at these facilities were all rated by the EPA in 2009 as having either high hazard potential or significant hazard potential.

Second, the AGO alleges that DEC violated the Clean Water Act citing, among others, that in 2015, Duke pled guilty to five counts of criminally negligent violations of the Clean Water Act. In addition to the four charges involving Dan River, one charge stemmed from the unauthorized discharge of pollutants from an unpermitted channel that allowed contaminated water from its coal ash basin at its Riverbend Steam Station to be discharged into the Catawba River from at least November 8, 2012 through December 30, 2014. Ex. Vol. 12 pp. 355-356, 400-01; Ex. Vol. 12, pp. 302, 346-347. The AGO also cites that after the Southern Environmental Law Center threatened to filed civil lawsuits, DEQ initiated lawsuits against all of the Company's facilities which was resolved by the parties. The AGO also cites that on March 4, 2016, the DEQ issued Notices of Violation to Duke Energy Carolinas related to seeps. Tr. Vol. 11, p. 267. On January 8, 2018, the Company announced its entry into a proposed Special Order by Consent with DEQ to settle alleged water quality violations at the Allen, Marshall, and Cliffside Steam Stations. Id. Each of the seeps identified and addressed in the Special Order exhibited some indication of the presence of coal ash wastewater. Id. The Company paid $84,000 ($4,000 each for 21 seeps identified at these facilities prior to January 1, 2015) and committed to dewatering six coal ash ponds at these three facilities. Id. The resolution of these seeps is independent of the requirements of the CCR Rule and CAMA, and therefore any activities employed to resolve these seeps should be disallowed. Id.

Third, the AGO claims that DEC violated the 2L groundwater standards citing that in 2012 and 2013, when all of Duke's sites were monitored and the groundwater data gathered, the Company found and the EPA noted that there were exceedances of the groundwater 2L standards at all eight sites. 40 CFR Parts 257 and 261, 80 Fed. Reg. 74

(Apr. 17, 2015), p. 21455; AGO Late-Filed Exhibit 1-K-Nov. 4, 2013 Ash Basin Groundwater Summaries. The AGO provides that the Company gave notice of potential legal claims arising from groundwater contamination to its insurers in 1996 and 1997. In that correspondence, Duke advised its insurance carriers, AEGIS and Lloyd's of London, that it may have legal exposure for pollutant discharges from coal combustion residuals ponds at its coal-fired power stations. Ex. Vol. 10, p. 528; Ex. Vol. 10, p. 538. The AGO further states that on November 3, 2013, Duke Energy Corporation prepared a breakdown of data regarding exceedances of the 2L water quality standards for all of its facilities and found exceedances at all eight of the Company's plants. AGO Late-Filed Exhibit 1-K-"Nov. 4, 2013 Ash Basin Groundwater Summaries" Duke_USAO_01448182. Significantly, Allen Steam Station, Buck Steam Station, Dan River Steam Station, and W.S. Lee Steam Station had exceedances of both the primary and the secondary standards. Lastly, in its settlement of the 2013 court case, DEC agreed to perform groundwater remediation per CAMA and 2L. The AGO argues that CAMA only applies to surface impoundments, not inactive ash areas, N.C.G.S. 130A-309-200 et seq. (2017); therefore, any costs associated with the excavation and removal of inactive ash areas are patently related only to the Company's violation of groundwater regulations and should be disallowed.

The AGO further argues that DEC disregarded the law citing that Mr. Wells testified that "there was no obligation in the 2L rules to monitor groundwater quality" after the corrective action requirements were added, and in fact, the Company considered itself "under no universal obligation to monitor for groundwater impacts" until required to do so via a NPDES permit or other regulatory requirement mandated by the regulatory agency. Tr. Vol. 24, pp. 229-230. The AGO argues that the 2L Rules, since their promulgation in 1979, are and have always been founded on strict liability and self-enforcement principles. 15A N.C.A.C. 02L .0101 et seq. As stated in its Policy provisions, "[n]o person shall conduct or cause to be conducted, any activity which causes the concentration of any substance to exceed" the water quality standards specified in these Rules. 15A N.C.A.C. 02L .0103(d) (2017). As these Rules "are applicable to all activities or actions, intentional or accidental, which contribute to the degradation of groundwater quality," DEC had a duty to comply with these Rules. Id.

Next, the AGO argues that DEC understood the changing regulatory landscape for years and did not change its practices. The AGO cites many documents that prove this point. The AGO contends that as early as 2003, more than ten years prior to the enactment of CAMA and the Federal CCR Rule, DEC knew that at some point in the future, it would no longer be able to store wet ash in unlined surface impoundments but did nothing about it. Ex. Vol. 16, Pt. 2, p. 123. In January 2007, DEC noted that it would "be required to construct landfills for disposal of its non-saleable CCP . . . in the years to come ..." Ex. Vol. 16, Pt. 3, p. 50. In a document called "Duke Energy Environmental Management Program for Coal Combustion Products" dated May 29, 2007, Duke called "disposal in surface impoundments" the highest risk method of disposition of coal ash, and stated that this risk assessment should be used to support planning and management decisions. Ex. Vol. 16, Pt. 3, p. 60. In its 2010 Securities and Exchange 10-K filing, Duke Energy Corporation advised that it currently estimated that it would spend $131 million "over the period 2011-2015 to install synthetic caps and liners at existing and new CCP landfills and to convert some of its CCP handling systems from wet to dry systems to comply with current regulations." Ex. Vol. 16, Pt. 3, p. 238. Other documents include a 2013 Ash Basin Closure Strategy (AGO Late-Filed Exhibit 1-E-"Ash Basin Closure Strategy" p. Duke_USAO_01448357), review notes of an Environmental Review given to the Board of Directors of Duke Energy Corporation on August 27, 2013, (AGO Late-filed Exhibit 1-I.), and a presentation made to the Senior Management Committee on the "Ash Basin Closure Strategy on November 25, 2013. AGO Late-Filed Ex. 1-L p. Duke_USAO_1329810. The AGO states that in January 2014, less than a month before the Dan River spill, Duke Energy Corporation's Senior Vice President of Environmental Health and Safety acknowledged in a presentation to the Senior Management Committee that the Company's "coal ash is impacting the groundwater at all locations [and that] [t]his is not an overnight event, ash has been managed in this fashion for decades and it will take decades to close the ponds." Ex. Vol. 10, p. 611. Two of the recommendations given to the Senior Management Committee were to 1) "aggressively pursue closure of ash ponds at all decommissioned sites" and 2) "close all active ash ponds." Id. at 659. The AGO argues that despite the need to pursue the closure of its ash ponds and to convert to dry ash handling, DEC never implemented its own internal recommendations prior to the Dan River spill and the enactment of CAMA and the Final CCR Rule.

Next, the AGO argues that DEC failed to meet industry standards as it failed its duty to be a reasonable and prudent operator. The AGO further argues that under any standard, the Intervenors have shown the costs are not reasonable for cost recovery. The AGO states that it has shown discrete instances of imprudence, that prudent alternatives existed, and that imprudently incurred costs are enormous and certain disallowances should be made by the Commission. The AGO further argues that the Commission may "not allow an electric public utility to recover from the retail electric customers of the State costs resulting from an unlawful discharge to the surface waters of the State from a coal combustion residuals surface impoundment." N.C. Gen. Stat. § 62-133.13 (2014). This section of CAMA applies to discharges occurring on or after January 1, 2014. N.C.G.S. Session Law 2014-122, Sen. Bill 729, Part I, § (1)(b). The AGO states that it is not possible to determine exact disallowances, but the AGO contends that there are costs that would have resulted from the unlawful discharges to the surface waters of the State from at least the Riverbend plant cited in the Federal criminal case from January 1, 2014 to December 30, 2014. Ex. Vol. 12, pp. 400-401.

Next, the AGO submits that DEC should not receive "carrying costs" during amortization of the deferred CCR costs by placing the unamortized balance in rate base because the deferred CCR costs are not used and useful but rather are special operating expenses. According to the AGO, operating expenses are recoverable without return pursuant to N.C. Gen. Stat. § 62-133(b)(3) and State ex rel. Utils. Comm'n v. Thornburg (Thornburg I), 325 N.C. 463, 475, 385 S.E.2d 451, 458 (1989). Further, the AGO submits that the unamortized balance of the CCR deferred costs are similar to those considered in State ex rel. Utils. Comm'n. v. Carolina Water, 335 N.C. 493, 507, 439 S.E.2d 127, 135 (1994) (Carolina Water), where the Supreme Court considered whether the Commission erred when it treated utility plant that was not in service at the end of the test year – and would not be returned to service – as "an extraordinary property retirement," allowed amortization of the unrecoverable costs over ten years, and included the unamortized portion in rate base. The Court concluded that the costs were for plant that was not used or useful and, thus, the unamortized costs should not have been included in rate base. As the Supreme Court explained: "Including [these] costs in rate base allows the company to earn a return on its investment at the expense of the ratepayers." Id. at 508, 439 S.E.2d at 135.

Further, the AGO contends that the coal ash activities and expenditures are no longer related to ongoing or active property used or useful for providing utility service. The AGO states as support for this position that the costs in the asset retirement obligation are for the closure of basins and disposal of coal ash that Duke has identified with retired coal-fired steam stations (Ex. Vol. 16, Pt. 1, p. 24); the AGO argues that these coal ash closure and disposal costs are typically recovered in depreciation expense for long-term assets, as is recognized in the Commission's 2003 Order on Asset Retirement Obligations, DEC's internal evaluation of coal ash in 2014 contemplated the use of depreciation reserve funds, and Duke response to questions about whether such costs are included in depreciation expense in which DEC stated that the costs were not thought to result in a net negative salvage value, not that depreciation is inapplicable to such costs (Ex. Vol. 10, p. 691); depreciation costs are recovered over the 'useful life' of the asset. The AGO argues that no attempt has been made to define a useful life for the "property" that has generated coal ash expenditures and the retired plants where most of the costs were incurred do not have a remaining 'useful life' and no attempt has been made to identify the cost components, or consider the distinction between expenditures at operating versus retired plants or between expenditures such as those for construction of a landfill versus transportation costs.

The AGO posits that the fact that Duke has created an Asset Retirement Obligation for the coal ash expenditures does not dictate how the Commission must treat the costs for regulatory purposes. Deferral accounting is used to keep the regulatory accounting the same until a change in regulatory accounting is authorized. The AGO argues that imposing these coal ash costs on current ratepayers raises intergenerational fairness given DEC's failure to take action earlier. The AGO highlights that the Commission has previously dealt with the intergenerational issue when it considered whether to allow the recovery of manufactured gas plant clean-up costs based upon new environmental requirements. The AGO states that the Commission allowed recovery of the clean-up costs, however the amount was amortized over a period of years and no carrying costs were allowed on the unamortized balance.

The AGO contends that DEC's request to recover the deferred costs involves single-issue ratemaking, i.e., Duke seeks to recover coal ash costs going back to the beginning of 2015 – plus carrying costs – without review of the other rate elements that were in effect in 2015 that might offset the need for the cost recovery. With respect to the ARO, the AGO contends that DEC failed to request authorization to defer the coal ash costs before they were incurred and that the deferral in this case relates to Duke's establishment of an Asset Retirement Obligation for costs that are already accounted for in rates through amortization and depreciation. Lastly, the AGO argues that Duke's proposal to recover $201 million per year for ongoing coal ash costs as regular operating expenses is unreasonable and should be denied. Instead, Duke should be authorized to defer future costs for recovery in a future general rate case.

In its post-hearing Brief, CUCA contends that DEC's request for 100% CAMA compliance cost recovery is not appropriate. CUCA submits that DEC's costs are overstated and that many are the result of DEC's negligence, which is most clearly highlighted in DEC's guilty plea in the federal criminal environmental proceeding. CUCA supports an equitable sharing of the CCR cleanup costs due to the fact that CAMA costs are much higher than the CCR Rule compliance costs and that DEC's mismanagement directly led to the passage of CAMA. CUCA states that a 25% recovery is equitable. Further, CUCA contends that the CCR Rule is a self-implementing rule which has not been triggered by any citizen suits, and that in the absence of a regulatory directive to do so, DEC should not have pursued regulatory closure of operating sites. CUCA asks the Commission to revisit its analysis of management penalty in the DEP rate case order stating that the $30 million penalty amounts to a 1%[55] penalty which is too low based upon the evidence of DEC's negligence and criminal acts to come to a more fair result in this case. CUCA contends this division of costs sends the message that DEC is not being held responsible for its actions. Lastly, if the Commission does allow a similar 1% penalty in this case, it should also decrease the return on equity as DEC becomes a less risky company.

In its post-hearing Brief, CIGFUR III argues that DEC should not be allowed an equity component in the calculation of its deferred coal ash remediation carrying costs and that the appropriate amortization period is ten to fifteen years as opposed to five. CIGFUR III states that the total cost to defer is $497 million and that the carrying charges associated with the incurred coal ash costs since 2015 are $27 million, $6 million is associated with the cost of debt and $21 million is associated with the cost of equity. CIGFUR III further states that amortizing over 5 years results in annual amortization expense of $104.8 million, plus a $29.9 million net tax return, for a total requested revenue requirement of $135 million for deferred coal ash pond closure costs. CIGFUR III argues that the carrying costs should not include the equity component and that the deferral should be financed at the lowest option, which is the cost of debt. Allowing the equity component increases the amount charged to DEC's ratepayers and is inappropriate for such a significant expense that fails to enhance reliable service. CIGFUR III submits that the CCR costs were incurred over many decades and the stored coal ash is no longer used and useful in the provision of electric service. With respect to the run rate, CIGFUR III argues that DEC should not recover the run rate of $201 million and that DEC should defer ongoing costs for future recovery in its next rate case.

Sierra Club, in its post-hearing Brief, first discusses the legal standard for setting just and reasonable rates. Sierra Club argues that the closure of DEC's CCR basins is

[55] One percent relates to the penalty amount in relation to the Company's total CCR expenditures to comply with CAMA and the CCR rule, including future expenditures. Further, in relation to the DEP case, the 1% does not include the approximately $10 million discrete disallowance for transportation costs.

not in direct response to the CCR Rule or CAMA, but was made necessary because of DEC's unlawful discharges of CCR constituents to surface waters, and, therefore, DEC's closure costs are not recoverable under N.C. Gen. Stat. § 62-133.13. Further, Sierra Club contends that all of DEC's CCR basins are unlawfully discharging pollutants into surface waters and/or groundwaters, and that the only way to stop these unlawful discharges is to close the ponds and eliminate the source, the coal ash. Therefore, Sierra Club concludes that the cost of pond closures results from the unlawful discharges and are not recoverable.

Sierra Club submits that DEC failed to meet its burden to prove that storage of CCRs in unlined, leaking basins for decades was a reasonable and prudent way for DEC to manage its CCRs. According to Sierra Club, the DEC evidence provided by witnesses Kerin, Wells and Wright about the historical handling of CCRs being reasonable, prudent and consistent with industry standards over time is not credible. Rather, Sierra Club contends that: (1) DEC's groundwater monitoring did not comply with the EPRI standards set forth in EPRI's CCR manuals; (2) that DEC's continued use of unlined basins was contrary to the national trend toward lined basins or dry fly ash handling systems; and (3) that DEC's response to the surface water and groundwater pollution shown by its monitoring reports, once it finally began monitoring, was not reasonable or adequate. Sierra Club states that DEC's first facility to be converted to dry fly ash handling was the Belews Creek plant in 1983, after DEC became aware that selenium from sluiced coal ash was killing the fish in Belews Lake. The result, according to Sierra Club, was a 75% decrease in selenium concentrations.[56] Yet DEC did not use this information and experience to perform investigations at other plants, or to convert to dry fly ash handling at other plants.

Sierra Club also cites DEC's criminal pleas as evidence that DEC allowed unauthorized discharges of pollutants into surface waters. Sierra Club states that the environmental audits conducted as a part of DEC's plea arrangement identified unauthorized seeps containing pollutants above background levels at all DEC plants. Sierra Club contends that the evidence these unauthorized discharges of pollutants have been occurring for an undisclosed amount of time, and, pursuant to N.C. Gen. Stat. § 62-133.13, provide the basis for the Commission to deny all costs of dewatering the CCR basins, at a minimum.

With regard to groundwater pollution, Sierra Club states that DEC failed to follow the industry standard for monitoring compliance with the 2L requirements and, instead, conducted initial sampling at the Allen plant, then extrapolated that data to conclude that there was no violation of the 2L standards at DEC's other seven plants. Sierra Club contends that DEC did not conduct consistent groundwater monitoring at all of its plants until the 2000s, and that similar to the surface water audits the court ordered ground water audits found that CCR constituents are in the groundwater beneath all of DEC's CCR basins. In addition, Sierra Club points to DEC's 1996 insurance letter as proof that DEC

[56] The selenium levels of concern at this site were from water discharges allowed from the NPDES permit rather than from groundwater leachate.

knew about contamination above the 2L standards at Allen, Belews Creek, Dan River, Marshall and W.S. Lee as early as 1996.

Sierra Club submits that the manner in which DEC failed to inspect and maintain the Dan River basin is indicative of its history of mismanagement and inaction with respect to CCR, and that this is conclusive evidence of imprudence, along with the following decisions made by DEC during the last 30 years:

(1) Failing to follow industry standards to stop using unlined basins.
(2) Waiting 20 years after the fish kill at Belews Creek to convert other plants to dry fly ash handling.
(3) Not conducting preliminary site investigations at all plants after the fish kill at Belews Creek.
(4) Waiting 30 years to regularly monitor ground water, contrary to the industry standard as of 1981.
(5) Not taking any action in response to the 1981 or 1982 EPRI manuals or the 1988 EPA Report, such as switching to lined basins, monitoring groundwater and dewatering basins.
(6) Spending millions of dollars on a leachate collection system at Allen and Marshall, then dumping the leachate into unlined basins at Allen and Marshall.

Moreover, Sierra Club argues that DEP's closure plans for its Allen and Marshall CCR basins do not comply with the CCR Rule or protect against continued discharges, and, therefore, DEC's proposed run rate should be rejected. Sierra Club contends that capping in place the Allen and Marshall CCR basins will not protect against continued contamination of ground water due to leaching of coal ash constituents into groundwater or into surface waters through migration.

NC WARN contends that DEC should not be allowed to recover any costs for the mitigation and cleanup of its CCR basins based on its extensive managerial mistakes and failures to take prompt action to correct known liabilities, and that no CCR costs should be borne by ratepayers. According to NC WARN, DEC has not met its burden of showing which of its CCR costs are capital expenses and which are operating expenses, N.C. Gen. Stat. § 62-133(b)(1) limits rate base recovery in rates to "property used and useful," and the statute does not include operating costs. As such, DEC's costs of compliance with federal and state directives stemming from CCR violations, and court orders mandating cleanup cannot be placed in rate base or otherwise recovered.

NC WARN also states that a review of the NC Clean Smokestacks Act is helpful because it provides guidance on what costs should not be allowed, such as costs incurred by the utility for failure to comply with any federal or state law, rule, or regulation for the protection of the environment or public health, and criminal or civil fines and penalties. N.C. Gen. Stat. § 62-133.6(a)(2). NC WARN asserts that the evidence shows that all of the costs incurred by DEC relating to CCR came from court orders and criminal plea agreements, and that DEC took no actions voluntarily, even actions that could have minimized subsequent costs and mitigated environmental damage. Further, NC WARN states that the evidence shows that DEC "knew or should have known" about the significant problem of leaking CCR basins in the early to mid-1980s, if not before, and that the industry standard increasingly became lining CCR basins to prevent water contamination. NC WARN points to DEC's insurance letters in 1996, 2011, and 2016 regarding potential damages and future compensation for mitigation and cleanup costs as significant evidence of what DEC knew or should have known, and contends that the refusal by the insurance companies to cover these multi-million dollar claims demonstrates DEC's culpability for at least the last 20 years. In conclusion, NC WARN submits that DEC mishandled its coal ash for decades, taking the least expensive options, and disregarding the substantial negative impacts of coal ash on families, property, and water supplies adjacent to the coal ash basins, and that the evidence demonstrates criminal negligence, millions in fines and penalties, and a number of judicial decisions and regulatory actions requiring DEC to do what it should have done all along.

E. The Position of Public Staff Witnesses Garrett and Moore

Public Staff witnesses Garrett and Moore testified that they investigated the prudence and reasonableness of costs incurred by DEC with respect to its coal ash management. In addition, they reviewed the approach taken by DEC to determine the least cost method of achieving compliance with the laws and regulations governing coal ash management. Witnesses Garrett and Moore testified that in some circumstances, DEC incurred costs associated with management of coal ash from CCR units that were not required under State or federal law. In those circumstances, witnesses Garrett and Moore evaluated the specific facts and details surrounding those CCR units to determine whether they agreed that DEC's management of those CCR units was reasonable and prudent. To the extent they believed that DEC's actions and costs incurred were not reasonable nor prudent, they recommended that the Commission disallow these costs. In conducting their investigation, witnesses Garrett and Moore reviewed the closure plans and coal ash-related costs incurred for all of DEC's coal-fired facilities, conducted extensive discovery, participated in numerous meetings, and visited several of the DEC facilities in question. Tr. Vol. 21, pp. 19-20.

Witnesses Garrett and Moore did not take exception with DEC witness Kerin's general characterization of the applicable federal and State regulations addressing the management and closure of coal ash basins in North Carolina and South Carolina. They did, however, identify several decisions made by DEC they maintained that were not required by law or where lower-cost compliance options were available, which they described in further detail in their testimony. Tr. Vol. 21, pp. 20; 50.

With regard to DEC's Allen, Belews Creek, Buck, Cliffside, and Marshall plants, witness Moore noted that DEQ issued final classifications for these facilities as "Low to Intermediate Risk" in May 2016, and that DEP is in the process of establishing the permanent replacement water supplies required under N.C. Gen. Stat. § 130A-309.211(c)(1) and performing the applicable dam safety repair work at these sites. Tr. Vol. 21, p. 54. Upon completion of these tasks within the timeframe provided, the impoundments at these facilities will be reclassified as low-risk pursuant to N.C. Gen. Stat. § 130A-309.213(d)(1). He explained that CAMA requires, at a minimum, that the impoundment be dewatered and closed either by excavation or by placement of a cap system that is designed to minimize infiltration and erosion. Witness Moore noted that this approach is generally the most cost-effective means for closure of a CCR unit. He also testified that CAMA (S.L. 2016-95) does not require the submission of proposed closure plans for low- and intermediate risk impoundments until December 31, 2019, so DEC has not submitted a Site Analysis and Removal Plan (SARP) to DEQ for any of the Low to Intermediate risk facilities at this time. He maintained, therefore, that a prudence review of the closure plans would be premature, so witness Moore took no exception in the present case to DEC's current proposed closure method for the coal ash basins located at Allen, Belews Creek, Buck, Cliffside, and Marshall. Tr. Vol. 21, pp. 55-57.

Public Staff witness Moore took exception to DEC's closure method for the CCR units located at Buck Steam Station. Duke selected Buck, along with DEP's Cape Fear and H. F. Lee Stations, as the three beneficiation sites pursuant to N.C. Gen. Stat. § 130A-309.216, which required Duke to identify three sites located within the state with ash stored in the impoundments suitable for processing for cementitious purposes. Upon selection of the sites, Duke was required to enter into a binding agreement for the installation and operation of ash beneficiation projects at each site capable of annually processing 300,000 tons of ash to specifications appropriate for cementitious products, with all processed ash to be removed from the impoundments located at the sites. Tr. Vol. 21, pp. 58-61. Witness Moore also noted that the timeframe proposed by DEC for beneficiation of the Intermediate Risk sites extends beyond the closure timeframe called for in Section 3.(a) of S.L. 2016-95 for sites deemed Intermediate Risk, and that N.C. Gen. Stat. § 130A-309.215 provides a variance option for closure deadlines that are found to be in the public interest. Id.

Public Staff witness Moore testified that instead of selecting Buck, Duke should have selected the CCR units located at Weatherspoon as one of the three beneficiation sites as required by N.C. Gen. Stat. § 130A-309.216, where Duke has selected the excavation of CCR and beneficial use option, with contracts in place for the delivery of the coal ash material to facilities in South Carolina for use in the concrete industry. This would have allowed the Buck Station to instead utilize significantly lower cost closure options instead of cementitious beneficiation. CCR units at Buck could have been classified as low risk upon completion of the establishment of permanence replacement water supplies and completion of applicable dam safety repair work, and instead may have been eligible for closure under the "cap-in-place" closure method under CAMA, which would have significantly lowered closure costs for Buck. Tr. Vol. 21, pp. 59-61. Witness Moore therefore recommended that the Commission disallow the $10 million already incurred by DEC for the cementitious beneficiation project at Buck. Tr. Vol. 24, p. 108.

With regard to DEC's selected closure actions at the Dan River Plant, witness Moore took exception with DEC's decision to excavate and transport coal ash from Ash Stack 1 at Dan River off-site to the Maplewood Landfill in Amelia, Virginia. He contended that had DEC conducted an adequate assessment of on-site greenfield landfill options at the time it began evaluating off-site disposal options, it would have identified viable on-site disposal options that would have allowed DEC to dispose of all of the ash on-site without having incurred the added expenses associated with the off-site transfer and disposal. Tr. Vol. 21, pp. 62-70.

Witness Moore disputed DEC's position that the moratorium on CCR landfills, which was enacted on September 20, 2014, in Section 5.(a) of S.L. 2014-122, and expired on August 1, 2015, had any impact on DEC's ability to construct an on-site greenfield landfill at Dan River in a timely fashion. He also noted that there were no regulatory obligations related to coal ash management that required removal of CCR materials from Ash Stack 1 as stated by DEC, particularly under the aggressive timeframes required for high-priority sites under CAMA. He evaluated DEC's investigation of on-site landfill options, particularly along the western boundary of the property, and found that DEC had no records documenting any evaluation of the area. With regard to the reasons provided by DEC as to why it did not utilize the area between the combined cycle plant and the western property boundary, Public Staff witness Moore found no valid technical reasons why an adequately sized on-site landfill could not have been located along the western boundary to have handled all of the ash on-site without having to incur the significant costs associated with off-site transportation costs and construction of rail handling equipment. Tr. Vol. 21, pp. 64-66.

As a result of DEC's unnecessary actions to transport ash off-site from the Dan River facility, witness Moore recommended a total disallowance at the Dan River facility of $59.3 million from DEC's coal ash expenditures during this recovery period. Public Staff Moore Exhibit 4.

Witness Moore summarized the coal ash closure approach taken by DEC at its Riverbend facility. Witness Moore testified that CAMA required the excavation of CCR materials from the Primary Ash Basin and the Secondary Ash Basin, but there were no regulatory obligations that required removal of CCR materials from the Ash Stack Area or the Cinder Pit. Witness Moore did not take exception with DEC's plan to remove this additional material, but he did take exception with DEC's decision to utilize the Brickhaven structural fill facility for off-site disposal. Tr. Vol. 21, p. 70, 72. Witness Moore testified that the Brickhaven facility did not present any scheduling advantages or reduce costs, and instead resulted in increased delays and litigation resulting from community opposition to the proposed project. Witness Moore testified that the DEC-owned on-site landfill at the Marshall Facility should have been utilized for the disposal of all ash from Riverbend. Tr. Vol. 21, p. 86.

Witness Moore did, however, take exception to DEC's decision to haul approximately 17,000 tons of CCR material from the Ash Stack Area by truck to the R&B Landfill in Homer, Georgia. Instead, Witness Moore stated that DEC could have utilized the landfill at the Marshall Facility for the CCR material, resulting in shorter hauling distances and lower disposal costs. Witness Moore recommended that the Commission disallow the $489,600 premium paid to transport and dispose of the 17,000 tons of CCR material to the R&B Landfill, as opposed to the Marshall Station. Tr. Vol. 21, pp. 72-74.

Public Staff witness Garrett focused his testimony on the activities undertaken by DEC at its W.S. Lee site in South Carolina. Witness Garrett agreed with DEC's decision to utilize an on-site landfill to dispose of the ash material in the Primary Ash Basin and Secondary Ash Basin at W.S. Lee, noting that this approach was consistent with Duke Energy's stated guiding principles and provided a lower cost closure solution compared to an off-site landfill. Tr. Vol. 21, pp. 39-40. Witness Garrett also concurred with DEC's decision to take some actions at the Inactive Ash Basin (IAB) and the Old Ash Fill to mitigate risk associated with long-term environmental issues at the site, but he did not agree with DEC's decision to immediately begin excavation and transportation of ash to the R&B landfill in Homer, Georgia. Witness Garrett instead testified that DEC should have followed the recommendations of its consulting engineers, which recommended repair and maintenance on the IAB berm in 2014, rather than immediate excavation. Witness Garrett further stated that DEC failed to provide a regulatory or technical reason to substantiate immediate removal of the ash from the IAB. Witness Garrett therefore recommended that the Commission disallow approximately $27 million from DEC's request, which is the premium associated with the costs incurred by DEC to transport ash to Homer, Georgia, as opposed to excavating and landfilling on-site. Tr. Vol. 21, pp. 40-41.

Witness Garrett also took exception with DEC's plan to excavate and dispose of the coal ash material contained in the Structural Fill area at W.S. Lee, because the area was developed in accordance with all applicable environmental regulations, is not in close proximity to the Saluda River, has been effectively capped in place, and does not pose any environmental concerns in its present state. Id.

F. Public Staff Witness Junis' Equitable Sharing And Coal Ash Adjustment Testimony

Public Staff witness Junis listed three conceptual options for regulatory treatment of coal ash costs. The first option is to allow full recovery of coal-ash related costs on the grounds that the costs have been reasonably incurred to comply with CAMA and the CCR Rule. Tr. Vol. 26, p. 721. This is essentially the approach recommended by DEC, minus fines, penalties, and other specific costs listed in their federal criminal plea agreement as non-recoverable in rate proceedings. Id. The second option is to disallow recovery of costs to comply with CAMA on the grounds that CAMA is the direct consequence of imprudent DEC environmental violations. Tr. Vol. 26, pp. 721-22. The third option is to disallow the costs incurred to defend and remedy environmental violations, except to the extent that CAMA requirements increased the cost of remediation. Tr. Vol. 26, p. 722. Under this approach, which the Public Staff advocates in theory, disallowances would be based on the costs to remediate environmental violations rather than the costs flowing from CAMA compliance. Id.

While the Public Staff supports the third option in theory, witness Junis encountered "complicating factors" that led him to modify this preferred regulatory treatment for practical reasons. Id. He observed that, while some environmental violations are clearly due to Company negligence, others fall into a gray zone where they are neither clearly imprudent nor clearly reasonable. Tr. Vol. 26, p. 723. For instance, decisions to place coal ash in unlined impoundments could have been reasonable based on what DEC knew or should have known at the time the basins were constructed some decades in the past. Tr. Vol. 26, pp. 723-24. At the same time, Public Staff witness Junis explained that it can be unreasonable to impose on ratepayers the costs incurred because those impoundments leaked coal ash constituents and contaminated groundwater outside the compliance boundaries, in violation of state environmental laws and regulations. Tr. Vol. 26, p. 724. Witness Junis also noted that calculating the costs of many environmental violations would be too speculative as such calculations would involve estimations based on scenarios that did not occur (e.g., preventing violations through basin construction or modification some decades earlier, or remedying violations if CAMA had not been enacted). Tr. Vol. 26, p. 725.

Due to the complicating factors, witness Junis offered a more practical approach that would exclude certain coal ash costs from recovery in rates as follows:

(1) DEC litigation costs incurred during the test year in cases where there are environmental violations;
(2) costs to remedy environmental violations where the costs exceed what CAMA would have required in the absence of environmental violations;
(3) fines, penalties, and other costs associated with the federal criminal plea agreement involving the Dan River and Riverbend plants, payments to DEQ to settle the assessment of penalties involving the Dan River plant, and the penalty for groundwater violations at DEC and DEP plants including Belews Creek and Sutton;
(4) the adjustments and disallowances recommended by Garrett and Moore to the extent there is no double disallowance for the same item; and
(5) an equitable sharing of the remaining allowed costs of coal ash management through the deferral and amortization approach recommended by Public Staff witness Maness.

Tr. Vol. 26, pp. 727-28.

Witness Junis noted that DEC has removed the costs listed in item (3) above from its rate request. Tr. Vol. 26, p. 728. Thus, the regulatory treatment of those costs is not in dispute. The disallowances recommended by witnesses Garrett and Moore are discussed elsewhere in this order. The remaining cost exclusions listed by witness Junis include litigation-related expenses in cases of environmental violations. In this category, he recommended exclusion of $2,109,406 (total system, not just NC retail, as shown in Boswell Exhibit 1, Schedule 3-1(n), line 1) of test year outside legal fees for litigation of the state enforcement actions filed by DEQ alleging violations at all of DEC's North Carolina plants and, to any extent they have not already been excluded by DEC, for litigation of the penalties assessed by DEQ for violations at the Dan River plant. Tr. Vol.

26, pp. 730-31. Witness Junis asserted that there is compelling evidence of the environmental violations on which these legal actions were based. Tr. Vol. 26, p. 731. He referenced a number of the exhibits to his testimony detailing DEQ data in support of this assertion. Id.

For the category of costs to remedy environmental violations where the costs exceed what CAMA would have required in the absence of environmental violations, witness Junis identified, to date, $1,288,526 (total system) of expenditures incurred from January 1, 2016, through November 30, 2017, for extraction wells and treatment of groundwater at DEC's Belews Creek plant pursuant to the settlement agreement between DEQ and DEP in the Sutton penalty assessment case. Tr. Vol. 26, pp. 733-34. He took the position that these costs would not have been incurred but for unlawful contamination of groundwater by DEC's Belews Creek ash basins, and that these costs are over and above the lowest reasonable costs of CAMA compliance in the absence of violations. In addition to the costs associated with extraction wells and treatment of groundwater, witness Junis identified $857,350 of expenditures for selenium removal equipment at DEC's Riverbend plant on the grounds that this equipment had not been placed in operation at the time of his testimony. Tr. Vol. 26, p. 734. Witness Junis noted that there could be additional costs in this category in the future. Tr. Vol. 26, p. 732.

The final category for disallowance is based on an "equitable sharing" of all coal ash-related costs not otherwise disallowed. Tr. Vol. 26, p. 738. Witness Junis referred to witness Maness' testimony for description of how the equitable sharing should be implemented and the reasons for it. Id. Witness Junis further testified that "An equitable sharing is particularly appropriate in light of the extent of the Company's failure to prevent environmental contamination from its coal ash impoundments, in violation of state and federal laws." Tr. Vol. 26, p. 738. In support of his opinion, he noted the nature and extent of coal ash environmental problems addressed in the federal criminal plea agreement, unlawful discharges, dam safety deficiencies, and numerous groundwater violations. Tr. Vol. 26, p. 739. He added that the sheer number of legal actions against DEC for coal ash environmental violations, while not evidence of the Company's guilt, is suggestive of the extent of the problem. Tr. Vol. 26, pp. 739-40. Witness Junis asserted that the numerous lawsuits regarding DEC's non-compliance with N.C. Gen. Stat. § 143-215.1 and state groundwater rules would in all probability have led to environmental cleanup costs even if CAMA and the CCR Rule had not been adopted, and that the costs of impoundment closures under CAMA and the CCR Rule overlap what would otherwise have been coal ash cleanup costs under existing state and federal environmental laws and regulations. Tr. Vol. 26, p. 741. Based on DEC's culpability for environmental violations, witness Junis testified that an equitable sharing would be appropriate, whereas it would be unreasonable and unjust to burden ratepayers with all the coal ash-related costs when ratepayers were not culpable for the environmental violations. Tr. Vol. 26, pp. 741-42.

Witness Junis responded to DEC witness Kerin's assertion in his testimony that the EPA's 2015 Effluent Limitations Guidelines (ELG) Rule forced DEC to convert its coal-fired plants to dry ash handling. Tr. Vol. 26, p. 742. Witness Junis noted that conversion to dry ash handling or cessation of operations is a requirement of CAMA, which was enacted in 2014, and, thus, the ELG Rule, which was not promulgated until 2015, was not the driver of this outcome in North Carolina. Tr. Vol. 26, p. 743.

Witness Junis disagreed with Company witness Kerin's testimony that DEC had not done anything to cause it to incur any unjustified coal ash-related costs, and he disagreed with witness Wright's minimization in his testimony of the role of the Dan River spill on the enactment of CAMA. Tr. Vol. 26, pp. 743-44. He stated that Dan River spill "was a large contributing factor to the creation of CAMA, which forced the Company to take expensive corrective actions." Tr. Vol. 26, p. 744. He further noted that Senate President Pro Tem Phil Berger recommended that the spill be discussed in the General Assembly's next meeting in a press release issued four days after the spill, and that the first version of CAMA directly referenced the spill in its preamble. Tr. Vol. 26, p. 745.

Witness Junis also disagreed with Witness Wright's assertion that the Commission should treat DEC the same as it treated DNCP in its 2016 rate case, in which the Commission approved amortization with a return for DNCP's past deferred coal ash costs. Tr. Vol. 26, p. 747. Witness Junis stated that the volume of environmental regulatory action against Dominion was miniscule compared to that against DEC, and that this was borne out by the Company's own responses to Public Staff Data requests in which it failed to produce evidence of environmental violations by DNCP after 1993. Tr. Vol. 26, p. 748.

In supplemental testimony, witness Junis recommended disallowance of an additional $206,553 in expenditures for groundwater extraction and treatment at DEC's Belews Creek plant listed in DEC witness McManeus' second supplemental testimony, which updated coal ash costs through December 31, 2017. Tr. Vol. 26, pp. 752-53. This recommendation is based on the same grounds for the disallowance of groundwater extraction and treatment costs detailed in witness Junis' direct testimony.

In his initially filed and supplemental direct testimony, Public Staff witness Maness identified the following seven adjustments to the Company's proposed recovery of coal ash costs. Some of the adjustments incorporate recommendations from other Public Staff witnesses:

a. Witness Maness incorporated adjustments to reflect a prudent and reasonable level of coal ash expenditures as recommended by Public Staff witnesses Moore, Garrett, and Junis. Tr. Vol. 22, pp. 65-66, 147, 153-54.

b. Witness Maness recommended adjusting the N.C. retail jurisdictional allocation factors to (a) allocate the costs DEC has identified as "CAMA Only" costs by the comprehensive allocation factor, rather than a factor that does not allocate costs to South Carolina retail operations; and (b) allocate all coal ash expenditures by the energy allocation factor, rather than the demand-related production plant allocation factor.

c. Witness Maness recommended addition of a return on deferred coal ash expenditures from December 2017 through April 2018, to bring the total balance up to the expected effective date of the rates approved in this proceeding. Tr. Vol. 22, pp. 69-70. The Company accepted this approach in its Second Supplemental Filing, as noted above. However, the Company has calculated the 2018 net-of-tax debt carrying cost using a Federal income tax rate of 35%; witness Maness recommended using the updated 2018 rate of 21%. Tr. Vol. 22, pp. 149-50.

d. Witness Maness recommended calculation of the return on the deferred coal ash costs be made with a mid-month cash flow convention, rather than the beginning-of-month convention used by the Company. Tr. Vol. 22, p. 70. The Company accepted this approach in its Second Supplemental Filing, as noted above. However, the Company had continued to apply compounding at the end of January each year. Witness Maness continued to recommend compounding carrying costs at the beginning of January each year. Tr. Vol 22, p. 149.

e. In conjunction with the Public Staff's proposal for equitable sharing of coal ash costs between ratepayers and investors, witness Maness recommended amortization of the balance of deferred coal ash expenditures over a 25-year period, rather than the 5-year period proposed by the Company. Tr. Vol. 22, pp. 70-85, 153-54.

f. Also in conjunction with the Public Staff's proposal for equitable sharing of coal ash costs between ratepayers and investors, witness Maness recommended reversal of the Company's inclusion of the unamortized balance of coal ash expenditures in rate base; this reversal, in conjunction with the 25-year amortization period, would produce a 49% ratepayers / 51% investors sharing of the burden of deferred coal ash expenditures. Tr. Vol. 22, pp. 70-85, 153-54, 162.

g. Witness Maness recommended removal of the ongoing annual expense amount, or "run rate," proposed by DEC to recover additional coal ash management costs incurred from the date the rates approved in this proceeding become effective through the date rates become effective in DEC's next general rate case.

G. Company Witnesses – Rebuttal

Rebuttal testimony with respect to the reasonableness and prudence of the Company's coal ash basin closure costs was provided by Company witnesses Kerin, Wright, and Wells. Rebuttal testimony with respect to witness Maness' proposed adjustments was provided by witness McManeus. Rebuttal testimony with respect to the Company's entitlement to earn a return on the unamortized balance of coal ash costs, ARO accounting and the "used and useful" concept, was provided by witnesses Wright, McManeus, and Doss. Such testimony is summarized as follows.

1. Kerin

Company witness Kerin's rebuttal testimony responded to the direct testimony of Public Staff witnesses Garrett, Moore, and Junis, CUCA witness O'Donnell, AGO witness Wittliff, and Sierra Club witness Quarles. As in the DEP proceeding, witness Kerin testified that witnesses Garrett and Moore engaged in a robust analysis and investigation of the costs that DEC incurred to comply with the CCR Rule and CAMA, and he agreed with the majority of their conclusions. He also stated that based on a complete review of the applicable facts and real world conditions, he did not believe their suggested disallowances were warranted, and that they again missed or overlooked key facts in several of their recommendations. Tr. Vol. 24, pp. 90-92.

First, he disagreed with witness Moore's conclusion that it was imprudent and unreasonable for DEC to transport CCR material from Dan River to a landfill in Virginia until the on-site CCR landfill could be constructed, and with their recommended disallowance of $59,320,890, which represents the difference between the cost to transport the material off-site and the cost to dispose of it in what he classified as a hypothetical and impractical on-site landfill along the western property boundary. Witness Kerin stated that witness Moore conceded that the CAMA moratorium prohibited construction of new or expanded CCR landfills located wholly or partly on top of the Primary Ash Basin, Secondary Ash Basin, and the Ash Fill 1 and 2 areas. He also stated that, while witness Moore correctly asserted that the moratorium did not prohibit construction of landfills in other areas of the site, specifically near the western property boundary, based on the Company's exploration of off-site and on-site locations for a CCR landfill for the Dan River ash, locating the on-site landfill on the western property boundary was never a feasible option due to multiple factors that witness Moore did not consider. Tr. Vol. 24, pp. 92, 94-105, 131.

Witness Kerin explained that in June 2015, Duke Energy purchased two tracts of land near Dan River (the Hopkins Tracts), which together with the Dan River plant were subject to a City of Eden zoning ordinance that made landfill construction on those properties cost prohibitive. He explained further that, while DEC and the City of Eden entered into an agreement whereby the City amended its zoning ordinance to allow landfill construction on the Dan River property, several limitations were imposed on the location of an on-site landfill. The landfill could only be located on the Dan River Facility premises, not on the Hopkins Tracts. In addition, the on-site landfill needed to be located near the existing basins, and as remote from residential areas as feasible. Witness Kerin noted that the nearest location to the existing basins is within the footprint of the former ash stack, and that this is the location DEC chose for the landfill. This choice also minimized impacts to surrounding properties by ensuring that the landfill was located as far as feasibly possible from neighboring properties. He stated that, because witness Moore's proposed location, in contrast, was not closest to existing basins or as remote as feasible from residential areas, the City of Eden would not likely have approved the zoning required to construct the landfill in this location. Witness Kerin stated that, if witness Moore had considered the City of Eden agreement, he could not have concluded that his alternative landfill location was reasonable or prudent. Tr. Vol. 24, pp. 95-96.

Witness Kerin maintained further that construction of the landfill in witness Moore's proposed location would require complete excavation of a LCID Landfill on the site. He explained that DEQ had allowed Duke Energy to dispose of asbestos in the Dan River LCID Landfill, and stated his opinion that North Carolina regulators would not allow DEC to disturb a covered landfill containing asbestos. This is because, while asbestos that is covered and in a landfill poses little to no risk to environmental health or safety, when uncovered and disturbed through excavation, it becomes friable and will be released into the air, posing an unacceptable risk to workers and, potentially, neighbors. Witness Kerin also testified that, even if the Company were allowed to excavate the LCID Landfill, disposal of the fill material would have posed additional challenges. While witness Moore asserted that the Company could have disposed of the material at the Rockingham County Landfill, witness Kerin stated that it is not clear that that location would have accepted the volume of asbestos—at least 60,000 cubic yards—required to be excavated from the LCID Landfill. Even if Rockingham would accept the asbestos, because it imposes strict double-bagging requirements for asbestos waste, this requirement would prohibit pursuing this alternative from an operational and labor standpoint. Tr. Vol. 24, pp. 97-98.

Witness Kerin stated that DEC also located the on-site landfill so that it does not interfere with existing streams and wetlands on the Dan River Plant premises. He stated that witness Moore's alternative location would in contrast interfere with two streams and two wetlands and impact several others, which would have required the Company to apply for U.S. Army Corps of Engineers (USACE) and DEQ permits to address those impacts. He also stated that, in the Company's experience, it is not likely that USACE would have approved the requisite permits, or would not have done so in time for the Company to meet the closure deadline of August 2019, especially considering that another on-site location – the one chosen by DEC – would have no impacts to streams or wetlands. He contended that witness Moore's proposal neither avoids nor minimizes impacts to jurisdictional waters, and relies solely on cost as support for his location. He asserted that the location that DEC chose for the landfill allowed it to proceed without litigation or delay, and will allow it to meet its CAMA imposed excavation deadlines. Tr. Vol. 24, pp. 98-100.

Witness Kerin maintained in addition that witness Moore's alternative location did not consider elevation changes and other topographical features, such as the steep slopes on the alternative site that lead to and through streams and wetlands. He also asserted that the steep grading limits the airspace that can be realized for developing a lined landfill of the size needed, and the elevation of witness Moore's proposed location would result in the landfill being in neighbors' line of sight. Witness Kerin also asserted that the land along the western property boundary is not suitable for landfill construction, as the depth to bedrock is fairly shallow, leaving little room for excavation for fill volume, borrowing soil or buffering to groundwater. He asserted further that the slope to stream combination on the western and southern sides of witness Moore's proposed landfill location leaves no area for stormwater management on the low side of the landfill, and that significant borrow resources would be required to fill the toe of the slope to achieve enough buffer from the stream for landfill access and stormwater features, adding expense and time to the project. Further, he maintained that the Company would have needed to obtain a new construction permit and construct an industrial NPDES outfall through the service water pond in order to build witness Moore's proposed landfill, and that both the permit and the outfall would have required substantial time to obtain and construct and would have to be in place before construction on the landfill began. In addition, he maintained that the 100-year flood plain in this area intrudes into portions of witness Moore's proposed location, and would present additional permitting challenges and likely not leave sufficient space for required stormwater management features on the site. Tr. Vol. 24, pp. 100-02.

Finally, with regard to Dan River, witness Kerin maintained that, even if DEC could have overcome all of the obstacles to witness Moore's proposed site, the proposed disallowance was incorrectly calculated. He explained that witness Moore did not correctly calculate the Company's costs for excavating, transporting, and disposing of Ash Stack 1 off-site, and that his proposed $83,531,985 disallowed should be reduced by approximately $3.8 million that is actually attributable to excavation and transportation of ash from the Primary Ash Basin. Witness Kerin also asserted that witness Moore's cost estimates to construct his alternative landfill are too low. He explains that when the presence of asbestos and the need to relocate the warehouse building in the center of the alternative location are accounted for, the cost to build witness Moore's alternative location landfill jumps by $10,790,900 to $35,001,095, thereby reducing witness Moore's proposed disallowance further, to $44,742,265. Witness Kerin emphasized that, because witness Moore's proposed site was not a viable option and never considered by the Company for the myriad reasons he discussed, this recalculation is hypothetical, but that it shows that witness Moore's proposed disallowance is incorrect even if his suggested course of action were possible, which it was not. Tr. Vol. 24, pp. 103-05.

Witness Kerin also disagreed with witness Moore's contention that DEC should have chosen Weatherspoon over Buck as a beneficiation site, and with the recommendation that $10,612,592 associated with beneficiation costs at Buck be disallowed. N.C. Gen. Stat. § 130A-309-216 requires an impoundment owner to: (i) identify two sites by January 1, 2017 and an additional site by July 1, 2017; and (ii) enter into a binding agreement for the installation and operation of an ash beneficiation project at each site capable of annually processing 300,000 tons of ash to specifications appropriate for cementitious products, with all ash processed to be removed from the impoundments located at the sites. Witness Kerin maintained that in keeping with the timing requirements imposed by CAMA, Duke Energy identified Buck, H.F. Lee, and Cape Fear as the three beneficiation sites based on its conclusion that they offered the most feasible alternative and the best economic value to customers while complying with CAMA. While he agreed that reuse of ash at Weatherspoon is appropriate, and noted that the Company is selling Weatherspoon ash for reuse today, he disagreed that Weatherspoon was a possible choice for one of the three beneficiation sites required by CAMA. Tr. Vol. 24, pp. 93, 105-08, 131.

Witness Kerin explained that witness Moore mixes apples and oranges by contending that by selecting Buck as a beneficiation site and therefore supplying an additional 300,000 tons per year of CCR material to the concrete industry, the Company in turn reduced demand for the 70,000 tons per year of CCR material for the same purposes from Weatherspoon for which Duke Energy was unable to find a purchaser. He explained that Weatherspoon ash is sold under contract to cement manufacturers and is used as raw material or aggregate in the manufacture of cement, while beneficiated ash from Buck is used as a replacement for cement in concrete. Because these are separate products that are used for different purposes, the sale of beneficiated ash from Buck has no impact on the demand for ash from Weatherspoon. Tr. Vol. 24, pp. 105-06.

Witness Kerin maintained further that witness Moore's assertion that choosing Buck increased closure costs at that site compared to other closure options misses several key facts that support the decision to select Buck as the third beneficiation site. He noted that Weatherspoon contains only 2.4 million tons of ash, which is approximately one-third the 6.4 million tons at Buck, and that the Company reasonably considered the amount of ash available at the site, and the potential uses for the ash when making decision to invest in beneficiation at a particular location. Witness Kerin also maintained that Weatherspoon is in a poor geographic location in relation to the major markets for ash used in the cement industry. He explained that since trucking the ash is part of the cost of the sales, with its proximity to Charlotte and Greensboro, Buck is in a much better location for beneficiation, and has the highest revenue projection, followed by Cape Fear (Greensboro and Raleigh) and H.F. Lee (eastern North Carolina and Virginia). Witness Kerin noted further that, even after issuing an RFP, Duke Energy has only been able to secure a buyer willing to enter into a long-term contract for 230,000 tons of ash from Weatherspoon, but not the additional 70,000 tons to qualify the site for beneficiation. He also asserted that the statute's specific references to installation and operation of an ash beneficiation project and production indicates the General Assembly's intent that Duke Energy construct and operate technology such as carbon burn-out plants and STAR technology, rather than use the basic drying and screening operations occurring at Weatherspoon. Tr. Vol. 24, pp. 106-07.

Witness Kerin also disputed witness Moore's recommendation that the Commission disallow recovery of $2,000,100 related to DEC's purchase of nine adjacent parcels at Cliffside. He stated that witness Moore's conclusion ignores one of the Commission's and DEC's core policies, which is to encourage and promote harmony between public utilities, their users and the environment. He also noted that the cost of the Cliffside parcels was not included in the costs the Company is seeking to recover in this case, and has never been part of the Company's ARO and as such the recommended disallowance of these costs should not be granted. Tr. Vol. 24, pp. 93, 108.

Witness Kerin also objected to witness Moore's suggestion that the $489,000 in costs to ship ash from Riverbend to Homer, Georgia should be disallowed on the basis that the ash could have been shipped to DEC's Marshall Steam Station. Witness Kerin testified that shipping ash to Homer, Georgia was a reasonable, temporary solution that allowed DEC to begin required ash excavation within the mandatory time frame after Riverbend received its NPDES stormwater permit. He explained that the Company sent Riverbend ash to Marshall once that site became available, but that Marshall was not an available location in May 2015, when the Company began trucking ash from Riverbend pursuant to DEQ directives. Those directives, as contained in an August 13, 2014, letter from DEQ, requested that Duke Energy submit an excavation plan for Riverbend by November 15, 2014, and that it begin removing ash at Riverbend within 60 days of receiving DEQ approvals to do so, which included an NPDES Stormwater Permit. Since DEQ issued the permit on May 15, 2015, DEC had until July 15, 2015, to begin excavating Riverbend ash. He stated that while the Company was exploring long-term options to receive the Riverbend ash, it was still obligated to meet this deadline, and thus it was imperative that the Company find someone to haul and dispose of the Riverbend ash on a short turnaround. Waste Management National Services, Inc. (Waste Management) was able to meet that requirement, and began trucking ash from Riverbend on May 21, 2015, and transported the final load on September 18, 2015 (as opposed to February 2016, as asserted by witness Moore). DEQ approved Duke Energy's request to dispose Riverbend ash at Marshall on June 19, 2015, which did not allow enough time for the Company to accomplish all of the tasks required to utilize Marshall and still meet the 60-day deadline. Once those tasks were accomplished, DEC did begin transporting Riverbend ash to Marshall on July 22, 2015, seven days after DEQ's excavation deadline. Tr. Vol. 24, pp. 93, 108-10, 131-32.

Witness Kerin also clarified that DEC could not have stopped trucking Riverbend ash to the R&B Landfill once it began trucking to Marshall, as the Company was under contract with Waste Management to dispose of the ash at R&B for 17 weeks, or through September 18, 2015, and would have been in breach of contract if it had halted the ash transport before that date. He also stated that the Company's decision to enter into a 17-week contract was based on several factors, including the short turnaround needed for a contractor to truck and accept the ash, and the knowledge that this would be a temporary disposal site and resulting need to find a contractor willing to accept a limited tonnage of ash. Tr. Vol. 24, pp. 110-11.

Finally, witness Kerin noted that Public Staff witness Garrett agreed with the Company that the Inactive Ash Basin and the Old Ash Fill at W.S. Lee needed to be excavated. Witness Kerin disagreed, however, with witness Garrett's assertion that DEC should have delayed excavation of ash material from the Inactive Ash Basin (IAB) and Old Ash Fill at W.S. Lee in order to undertake a grading and slope stabilization project, excavate the overly steep sections of the IAB berm, and dispose of that ash on-site. Witness Kerin testified that this approach would not have been reasonable or prudent and therefore disagreed with witness Garrett's recommendation that the costs associated with transferring ash to Brickhaven ($27,275,192) should be disallowed. Tr. Vol. 24, pp. 93, 111-12, 132.

Witness Kerin testified that, consistent with a Consent Agreement entered into by Duke Energy and the SCDHEC in September 2014, which required excavation of the IAB, the Company excavated ash from this basin and trucked it to the solid waste landfill operated by Waste Management in Homer, Georgia. He explained that, based on available stability analysis, the IAB did not meet the required CCR Rule dam safety factors for maximum storage pool and liquefaction conditions. He concluded that it was therefore reasonable and prudent for DEC to begin excavation immediately. Witness Kerin also noted that at the time the Company was deciding how to manage the IAB, its priority was to address stability and erosion concerns on the river frontage along the IAB dike. He asserted that, due to the low safety factors of the IAB dike, the Company was already limiting equipment access on the dike crests, which limited work to the very narrow portion of downslope area that extended from the dike toe to the river's edge. Witness Kerin asserted further that the equipment necessary to implement witness Garrett's proposal could not have safety traversed the dike on the downslope, and that moving the heavy equipment to the downstream/river side of the downslope would have created undue risk