NORTH CAROLINA
PUBLIC STAFF
UTILITIES COMMISSION

December 4, 2020

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

Re: Docket No. E-2, Sub 1193 – Petition of Duke Energy Progress, LLC for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego; and Docket No. E-2, Sub 1219 – Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina

Dear Ms. Campbell:

Attached for filing are public and confidential versions of the Public Staff's Proposed Additional Findings, Evidence, and Conclusions (Coal Ash Related Issues) in the above-referenced docket.

By copy of this letter, I am forwarding a copy of the redacted version to all parties of record by electronic delivery. The confidential version will be provided to those parties that have entered into a confidentiality agreement.

Sincerely,

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

DWD/cla

Attachment

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219
DOCKET NO. E-2, SUB 1193

DOCKET NO. E-2, SUB 1219 In the Matter of 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 1193 In the Matter of Petition of Duke Energy Progress, LLC for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego	)	PUBLIC STAFF'S PROPOSED ADDITIONAL FINDINGS, EVIDENCE, AND CONCLUSIONS (COAL ASH ISSUES)

ADDITIONAL FINDINGS OF FACT

Recovery of CCR Costs

1. Duke Energy Progress, LLC (DEP) is subject to the federal Coal Combustion Residuals Rule (CCR Rule) and the North Carolina Coal Ash Management Act (CAMA). The CCR Rule and CAMA mandate the closure of the coal ash impoundments at the Company's coal-fired power plants.

2. The Company knew or should have known by the early 1980s that the wet storage of CCR in unlined impoundments had the potential to contaminate surrounding groundwater and surface water.

3. There is substantial evidence in light of the whole record showing that DEP's coal ash disposal practices, including its actions and omissions over the lives of the impoundments, have resulted in extensive violations of environmental laws and regulations for which DEP is culpable. These violations include groundwater contamination in violation of North Carolina's 2L rules and unauthorized seeps in violation of DEP's National Pollutant Discharge Elimination System (NPDES) permits and N.C. Gen. Stat. § 143-215.1.

4. Culpability is a relevant factor in determining what are "reasonable and just rates" under N.C.G.S § 62-133(d).

5. The Commission has historically approved cost sharing between shareholders and ratepayers for certain unusual costs of large magnitude, including the costs of abandoned nuclear plant construction and manufactured gas

plant remediation. Such cost sharing is reasonable and appropriate and within the Commission's discretion.

6. Due to the magnitude and extraordinary nature of the coal ash closure and remediation costs, as well as DEP's environmental violations and culpability for those violations, it is fair and reasonable to equitably share the coal ash remediation costs, net of disallowances, between ratepayers and investors pursuant to N.C.G.S. § 62-133(d).

CCR-Specific Disallowances

7. DEP's expenditures for groundwater extraction and treatment at the Asheville and Sutton plants are due solely to the Company's environmental violations and should be disallowed.

8. DEP's expenditures for the purchase of land at the Mayo plant were incurred to mitigate the risk of spreading groundwater contamination and should be disallowed.

9. DEP's expenditures for permanent replacement water supplies, through either the connection of eligible residential properties to public water supplies or the installation, operation, and maintenance of water filtration systems, are the direct result of the legislature deciding that coal ash constituents from DEP's impoundments created an unacceptable risk to people's groundwater wells in the vicinity of the coal ash impoundments, and should be disallowed.

10. DEBS, as agent for and on the behalf of Duke Energy Carolinas, LLC (DEC), and DEP (collectively, the Companies), entered into eMax Master Contract

Number 8323 with Charah, Inc. (Charah), for the disposal of coal ash from the DEC Riverbend and DEP Sutton Stations at the Brickhaven Mine (Charah Master Contract).

11. Pursuant to the Termination provisions of the Charah Master Contract, the Companies were required to pay Charah Prorated Costs calculated based on a Prorated Percentage. The method for calculating the Prorated Costs agreed to by DEBS on behalf of the Companies was fundamentally flawed due to the use of a Prorated Percentage that unreasonably inflated the Prorated Costs. Furthermore, DEBS failed to define key terms in the Charah Master Contract, and the resulting ambiguity exposed the Companies to an unreasonable and amount of risk, and resulted in DEP paying an unreasonable settlement, or “fulfillment fee,” to Charah.

12. DEBS’ decision, on behalf of the Companies, to execute the Charah Master Contract containing the flawed Prorated Percentage calculation and ambiguous terms rather than pursuing feasible alternatives resulted in costs that are not reasonable or prudent for recovery in rates from customers.

13. DEBS’ decision, as an agent for and on behalf of the Companies, to select the STAR beneficiation technology and to enter into a contract with The SEFA Group, Inc. (SEFA), for engineering and procurement services to comply with the coal ash beneficiation requirements of CAMA were reasonable and prudent.

14. After developing the engineering design and construction documents but before entering into a contract with Zachry Industrial Inc. (Zachry) for the engineering, procurement, and construction (EPC) of three coal ash beneficiation facilities, it would have been reasonable and prudent for DEBS to: (1) expand the bidder pool and rebid the construction of the three beneficiation projects, either before or after further developing the design with SEFA, (2) separate the three projects and possibly the components of the projects, (3) seek statutory relief, and (4) communicate with the regulator of the CAMA requirements, DEQ, regarding alternative options and compromise.

15. DEBS' decision, as an agent for and on behalf of the Companies, to enter into an EPC contract with Zachry for a substantially higher cost than estimated in the Request for Information (RFI) process, without first evaluating feasible options to reduce the cost to the Company and thereby ratepayers, was not reasonable or prudent.

16. After the enactment of CAMA, the CCR Rule, and the Mountain Energy Act (MEA), and prior to continuing to operate under the contract with Waste Management, Inc. (Waste Management), for the excavation, transportation, and placement of ash from the Asheville Station to the R&B Landfill in Homer, Georgia, it would have been reasonable and appropriate for DEP to properly evaluate an on-site landfill with a capacity of approximately 3 million tons.

17. DEP's continued reliance on evaluations of designs for landfills, capable of holding over 5 million tons of production ash and capping-in-place the

existing impoundments, performed before the establishment of the regulatory requirements set forth in CAMA, the CCR Rule, and MEA, was not reasonable.

18. DEP's mismanagement of the excavation of the basins at Asheville Station through its failure to properly evaluate an on-site landfill under the applicable regulations of the time and its decision to contract with Waste Management resulted in the Company incurring transportation costs that were not reasonable or prudent.

Coal Combustion Residuals Cost Deferral

19. Since its last rate case, DEP has incurred significant costs to comply with legal requirements applicable to its coal ash impoundments. DEP is entitled to recover the CCR costs established in this general rate case, in the manner and subject to the conditions set forth herein.

20. On a North Carolina retail jurisdictional basis, and after reflection of specific prudence disallowances found appropriate and reasonable by the Commission, the actual coal ash basin closure costs DEP has incurred during the period from September 1, 2017, to February 29, 2020 (Deferral Period), including carrying costs through the Deferral Period and further through August 31, 2021, amount to $293,101,000.

21. Continued deferral of certain CCR expenditures is appropriate.

22. It is appropriate to treat the CCR costs as deferred operating expenses and not as costs of property used and useful within the meaning and

scope of N.C.G.S. § 62-133 (b), and to disallow a return on the unamortized balance of the CCR costs.

23. Just and reasonable rates will be achieved by excluding from rate base the CCR costs and amortizing recovery of the CCR costs over a period of twenty-five (25) years.

24. DEP may recover its financing costs on the CCR costs incurred during the Deferral Period, up to the effective date of rates approved pursuant to this Order, calculated at the Company's previously authorized weighted average cost of capital.

25. The rates approved in this case will remain provisional until the Commission assesses any impact of the Supreme Court's decisions on the appeal of Docket No. E-2, Sub 1142, to the extent necessary to incorporate the results of that appeal into the revenue requirement approved herein.

26. The right to defer capital costs associated with CAMA or the CCR rule granted in the Commission's Order issued in Sub 1103 is modified and no longer applies to non-ARO projects. The deferral authorization granted in Sub 1103 is restricted to CCR-related costs directly related to an asset retirement obligation.

27. The Company should be allowed to continue, for regulatory accounting purposes, to defer ARO-related coal ash closure, disposal, and remediation costs from March 1, 2020, through the effective end-of-period date in

the Company's next general rate case. The amount of those costs actually allowed for recovery will be subject to review by the Commission in a general rate case.

CCR Insurance Claims

28. DEP shall vigorously prosecute lawsuits related to Coal Combustion Residual (CCR) insurance claims and the full amount of any recovery received under those insurance policies shall be credited to its ratepayers.

<u>ADDITIONAL EVIDENCE AND CONCLUSIONS</u>

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

The evidence supporting this finding of fact and conclusions is contained in the Application, Form E-1, and the testimony and exhibits of DEP witnesses Jessica L. Bednarcik, James Wells, and Marcia E. Williams, Public Staff witnesses Jay B. Lucas and Michael C. Maness, and AGO witness Steven C. Hart.

DEP has relied upon coal-fired power plants throughout its history, and depends upon coal-fired generation today. Coal ash, also known as coal combustion residuals, or CCRs, is a by-product of coal-fired generation. Since the 1950s, standard industry practice, at least in the Southeast, has been to deposit coal ash in coal ash impoundments, and such impoundments were constructed and were or are used at all of the Company's coal-fired generating units.

CCR surface impoundments contain certain elements, such as arsenic, boron, cadmium, sulfate, vanadium, and others that can, when present in sufficient concentrations, pollute surface water, groundwater, and drinking water. The United States Environmental Protection Agency (EPA) has studied CCRs and their proper management and handling since the 1970s. In 1993, it determined that regulation of coal combustion wastes as a hazardous waste was not warranted, and in 2000 determined that coal combustion wastes should instead be regulated as non-hazardous solid wastes under the Resource Conservation and Recovery Act (RCRA). The EPA first proposed specific regulations for the disposal of CCRs in 2010, and EPA's final rule – the CCR Rule – was promulgated on April 17, 2015. (Tr. vol. 15, 1449-50.) The CCR Rule has been subject to a number of legal challenges and modifications since its promulgation. (Id. at 1452-54.) North Carolina also enacted specific statutory requirements for coal ash management in CAMA, which became effective in 2014 and was amended in 2015 and 2016. (Tr. vol. 12, 35.)

The CCR Rule and CAMA introduced new requirements for the management of coal ash. The CCR Rule established location restrictions, design and operating requirements, groundwater monitoring, corrective action, and the closure of certain units, among other requirements. (Tr. vol. 15, 1451.) CAMA also established a number of requirements, including requirements for groundwater monitoring, corrective action, closure of all surface impoundments, and the provision of water supplies to households neighboring DEP's surface impoundments. (Tr. vol. 12, 37-40.) With regard to the closure of impoundments, CAMA created a risk classification process in order to determine a closure method and deadline for each impoundment. (Tr. vol. 12, 37.) DEP must comply with these new requirements under the CCR Rule and CAMA, which mandate closure of the Company's coal ash impoundments.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 2-6

The evidence supporting these findings of fact and conclusions is contained in the Company's Application, Form E-1, the testimony of public witnesses, and the testimony and exhibits of DEP witnesses Jessica L. Bednarcik, James Wells, and Marcia E. Williams, Public Staff witnesses Jay B. Lucas and Michael C. Maness, AGO witness Steven C. Hart, Sierra Club witness Mark Quarles, and CUCA witness Kevin W. O'Donnell.

Summary of the Evidence

DEP DIRECT TESTIMONY

DEP witness Bednarcik testified that DEP's CCR compliance actions and costs between September 1, 2017 and June 30, 2019, as well as those that were forecasted, had been reasonable, prudent, and cost-effective. (Tr. vol. 12, 33, 55-57.) She detailed key closure activities that the Company had undertaken at the Company's CCR sites. At the Mayo and Roxboro Plants, which earned low-risk classifications under CAMA, she stated that the Company developed Closure Options Analysis Reports, which demonstrated that cap-in place closure was environmentally protective and cost-effective. Witness Bednarcik explained that on April 1, 2019, DEQ ordered excavation of these impoundments, and that the Company has appealed the excavation order. She noted that until the appeal is resolved, DEP will execute activities at these sites that would be required for either excavation or cap-in-place closure. (Id. at 41-43.) These activities include acquiring permits and dewatering. (Id. at 44-45.) Witness Bednarcik concluded that each closure activity described in her testimony and "for which the Company is requesting cost recovery can be traced to a provision of the federal CCR rule, CAMA, or other state regulatory requirement." (Id. at 56.)

INTERVENOR TESTIMONY

Public Staff witness Lucas discussed in his testimony a set of historical documents that he testified showed "an evolving body of scientific knowledge over more than 50 years concerning the risks of environmental contamination resulting from storing coal ash in unlined impoundments, and alternative methods of coal ash management." (Tr. vol. 15, 1477-78.) According to witness Lucas, these documents demonstrated that, "by the early 1980s, the electric generating industry knew or should have known that the wet storage of CCR in unlined surface impoundments posed a serious risk to the quality of surrounding groundwater and surface water." (Id. at 1478.) In support of his argument, witness Lucas cited publications ranging from 1967 to 1988, including manuals published by the Electric Power Research Institute (EPRI) in 1981 and 1982, and a 1988 EPA Report. (Id. at 1476-80.)

Witness Lucas testified further that the Company had stated, in response to a Public Staff data request asking what evaluations or analyses DEP had conducted with respect to the 1979 Arthur D. Little Report, the 1981 and 1982 EPRI Manuals, the 1988 EPA Report, and the 2004 EPRI Decommissioning Handbook, that it "has not been able to locate a specific response to the document in question." (Id. at 1481.) Witness Lucas noted that the Company also referenced its response to a Sierra Club data request in which it provided a selection of pre-

2014 documents relating to the risks of storing coal ash in unlined impoundments. Witness Lucas discussed one of the documents provided, a 1979 evaluation conducted at the Mayo Plant by DEP and a contractor, Edwin Floyd (Mayo study). He explained that the report's conclusion that an adverse impact from an impoundment was "difficult to imagine" was contrary to Mr. Floyd's earlier suggestion for periodic groundwater sampling. He also testified that it would have been imprudent at the time to rely on an assumption that there would be no contamination rather than to actually test for contamination, and that groundwater monitoring wells were not installed at the Mayo facility until 2008. He added that the 1979 Arthur D. Little report, which was published a few months after the Mayo study, noted the risk of groundwater contamination from coal ash impoundments. (Id. at 1481-84.)

Witness Lucas testified that the publications cited in his testimony showed that: (1) storage of coal ash in unlined surface impoundments had the potential to contaminate groundwater and surface water, and (2) groundwater monitoring is necessary to show that coal ash has been disposed of safely. (Id. at 1478-79.) He stated that despite the available knowledge in the late 1970s and early 1980s with regard to the risks of disposing of coal ash in unlined impoundments, DEP failed to improve and modernize its practices. He argued that given the state of knowledge at the time, "DEP should have installed comprehensive groundwater monitoring well networks in the 1980s to determine if the risk was materializing." (Id. at 1480-81.) Witness Lucas stated that the Company continued to operate its coal ash impoundments at each of its coal-fired power plants until at least 2011.

He added that as a result of the adoption of air emission control technologies, constituents that were previously emitted into the air became part of the waste stream entering the Company's impoundments and landfills. (Id. at 1481.)

Witness Lucas testified that DEP has accumulated significant environmental violations associated with its coal ash impoundments, including unauthorized seeps in violation of its NPDES permits and 7,411 groundwater exceedances in violation of the state's 2L rules. With regard to seeps, he explained that while almost all earthen dams have seeps, DEP's dams impound coal ash wastewater, which cannot be lawfully discharged without a permit. (Id. at 1485-88.) He also explained that "engineered" or "constructed" seeps are those that were deliberately constructed. (Id. at 1485.) Witness Lucas described Special Orders by Consent (SOCs) entered into between DEP and DEQ for seeps at the Asheville, Cape Fear, H.F. Lee, Mayo, Roxboro, and Weatherspoon plants. These SOCs imposed upfront penalties of a total of $342,000 as settlement of all alleged violations due to seepage from 14 deliberately constructed seeps and 29 non-constructed seeps, and required the Company to undertake specific corrective actions. (Id. at 1485-87.) Witness Lucas testified that the deliberately constructed seeps have been included in the Company's renewed or modified NPDES permits, but argued that including these seeps in DEP's permits "does not retroactively condone them." (Id. at 1487.) He stated that their inclusion in a NPDES permit means the seeps must now be monitored, "affording a level of environmental protection that did not previously exist." (Id.)

Witness Lucas discussed the state's groundwater standards and explained that an exceedance of the standards at or beyond the compliance boundary that is not due to background levels constitutes a violation of the groundwater standards. (Id. at 1487-88.) He added that "such an exceedance is a violation regardless of whether corrective action is taken." (Id. at 1488.) In support of this interpretation of the 2L rules, witness Lucas cited an amicus brief filed at the North Carolina Supreme Court by DEQ. (Id. at fn. 58.) Witness Lucas stated that, based on DEP's own groundwater monitoring, the cumulative total of groundwater violations at DEP's coal ash impoundments in North Carolina has reached 7,411. He added that the Robinson Plant in South Carolina has reached 632 groundwater exceedances. (Id. at 1488.)

With respect to groundwater monitoring conducted pursuant to the federal CCR Rule, witness Lucas stated that the Company has identified 3,164 testing results determined to be statistically significant increases over background levels for Appendix III parameters, which are the first tier of parameters tested under the CCR Rule's prescribed procedures. (Id. at 1490.) He added that under the CCR Rule, DEP has been required to submit an assessment of corrective measures for all its coal-fired power plants, with the exception of Cape Fear, as a result of exceedances of background levels and groundwater protection standards. (Id.) Witness Lucas also testified that the Company has identified 277 testing results from groundwater downgradient of its coal ash impoundments that have exceeded background levels and groundwater protection standards for Appendix IV parameters. (Id. at 1491.)

Witness Lucas testified that DEP installed voluntary groundwater monitoring wells at Asheville, Cape Fear, H.F. Lee, and Mayo in 2007 and 2008, and that monitoring began at Roxboro, Sutton, and Weatherspoon in 1986, 1990, and 1990, respectively. He added that groundwater monitoring was first required at the Robinson plant in South Carolina in 1995. (Id. at 1491.) Witness Lucas stated that despite the adoption of the 2L rules in 1979 and the publication of the 1982 EPRI manual, which stated that groundwater monitoring is "necessary to provide convincing proof of a safe disposal practice," DEP did not begin groundwater monitoring at some of its facilities until three decades later. (Id. at 1491-92.) He added that the Company did not conduct comprehensive groundwater monitoring "until even later." (Id. at 1492.)

Witness Lucas testified that when asked in a data request what actions it took in response to each exceedance prior to 2009 at its voluntary groundwater monitoring wells, the Company discussed a 2004-2006 investigation conducted at the Sutton facility, which concluded that groundwater contamination was localized and minor and could be adequately controlled by administrative controls and land use restrictions. Witness Lucas noted that testing at the Sutton site in the 2010s showed elevated levels of boron, iron, manganese, thallium, selenium, cadmium, and total dissolved solids. He added that DEP's response to the data request "did not indicate any actions taken for any other exceedances at any other sites." (Id. at 1492-93.) Witness Lucas testified that when DEP detected exceedances of the groundwater standards at its coal ash sites, it should have installed sufficient monitoring wells to determine to what extent they were attributable to the impoundments, to what extent they were attributable to other sources or background levels, and the extent and nature of any potential environmental degradation. (Id. at 1493.)

Witness Lucas testified that DEP has incurred costs related to its noncompliance with environmental regulations, and that the Company will continue to incur substantial costs to remedy those violations and prevent risks of future violations. He argued that while the Company calls such costs "compliance costs" for meeting the requirements of CAMA and the CCR Rule, "they also reflect DEP's non-compliance with longstanding environmental regulations." (Id. at 1494.) Witness Lucas opined that the evidence shows DEP would have incurred substantial corrective action costs under the state's 2L rules even in the absence of CAMA and the CCR Rule. (Id.)

Witness Lucas next discussed his equitable sharing recommendation. He testified that "[c]ertain costs are so clearly and directly due to the Company's failure to comply with environmental regulations that none of those costs should be assigned to ratepayers." (Id. at 1506.) He explained that the Public Staff could not conduct a traditional prudence review of the Company's historical coal ash management, because even where some of the Company's action or omissions appear imprudent, the quantification of costs directly resulting from such acts or omissions would be speculative. He also stated that where DEP's coal ash management was arguably prudent, the Company bears some degree of responsibility for its extensive environmental violations. (Id.)

During the hearing, witness Lucas confirmed that the Public Staff's equitable sharing recommendation was not based on a prudence analysis, and that conducting a prudence evaluation for costs that DEP could have incurred in the past would have been too speculative. (Id. at 1819-20.) On redirect, witness Lucas referred to a DEP response to a Public Staff data request in which the Public Staff requested that DEP estimate costs for specific CCR-related actions such as groundwater monitoring, groundwater extraction and treatment, and dry fly ash handling, in 1974, 1984, 1988, and 2000. Witness Lucas read from the data request response,[1] in which DEP stated that:

> Estimates of the nature requested by the Public Staff would be speculative and therefore unreliable. Using 2020/hindsight to develop site-specific estimates for activities covering a four-decade span of time would, as Commissioner Clodfelter indicates, require the impossible construction and evaluation of several different alternative histories and realities."

Witness Lucas agreed that, from this response, it appeared that DEP also believed it would be too speculative to attempt to quantify costs related to historical coal ash management practices in this case. (Id. at 1821-23.)

Witness Lucas argued that an equitable sharing of the Company's coal ash costs is appropriate in light of the Company's failure to prevent environmental contamination from its coal ash impoundments, in violation of state and federal laws. In addition to the seeps and groundwater violations witness Lucas discussed earlier in his testimony, and in addition to the violations admitted in the Company's federal criminal negligence case, witness Lucas referred to "numerous dam safety

[1] Lucas/Maness Public Staff Redirect Exhibit Number 2.

issues” found at DEP’s coal ash impoundments immediately following the 2014 Dan River spill and again two years later. (Id. at 1507.) He added that the Company, in general, did not conduct comprehensive groundwater monitoring until DEQ required it to do so by letter in December 2009.[2] Witness Lucas testified that it is notable that the Company’s number of groundwater standard violations has increased by 4,554, or 159%, since his testimony in the last DEP rate case. (Id. at 1508.)

Witness Lucas testified that the Company’s failure to comply with environmental regulations with respect to its coal ash impoundments “undoubtedly” contributed to the adoption of both the CCR Rule and CAMA, “which in turn led to significant new compliance costs.” (Id. at 1508-09.) He noted that the Company’s non-compliance with its NPDES permits, the Clean Water Act, and the state’s 2L rules would have led to cleanup costs from litigation or enforcement actions even if the CCR Rule and CAMA had not been adopted. (Id. at 1509.) Witness Lucas concluded that “[d]ue to its environmental violations, DEP has a great deal of culpability for the compliance costs related to remediation and ash basin and storage unit closures, and would likely have incurred substantial coal ash corrective action costs even without the CCR Rule and CAMA, whereas ratepayers are not culpable at all for those costs.” (Id. at 1510.) He added that the equitable sharing of CCR management costs, as further discussed by Public Staff witness Maness, is reasonable. (Id.)

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[2] Lucas Exhibit 17.

Lastly, witness Lucas compared the Public Staff's equitable sharing recommendation in the DEP and DEC rate cases to that in Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina's (Dominion's) rate cases. He first explained that the extent of groundwater contamination at Dominion's plants was not known to the Public Staff at the time of the Public Staff's testimony in the 2016 Dominion rate case, in which the Public Staff did not recommend equitable sharing, or at the time of the 2017 DEP rate case. He also explained that in Dominion's recent 2019 rate case, Dominion's environmental compliance issues became more apparent, resulting in a recommended 40/60 sharing between ratepayers and shareholders. (Id. at 1512-17.) Witness Lucas explained the difference in its 40/60 recommendation for Dominion and its 50/50 recommendation for DEP by stating that "the Public Staff believes that Dominion has a poor environmental compliance record, yet one that is better than that of DEP." (Id. at 1517.) He stated that, among other things, there is evidence of thousands of groundwater violations for DEP, while the number of groundwater exceedances at Dominion's facilities is lower. He also stated that the evidence of violations by Dominion is less clear because of a different regulatory framework and poor recordkeeping on the part of Dominion. (Id.)

Witness Lucas testified that in the 2019 Dominion rate case, the Commission set a ten-year amortization period for Dominion's coal ash costs, with no return on the unamortized balance, resulting in a sharing that allocated approximately 26% of costs to shareholders and 74% of costs to ratepayers. (Id. at 1518-19.) He stated that in the present case, the Public Staff is recommending a 50/50 sharing, and that the recommendation to allocate a higher percentage of coal ash costs to DEP shareholders than to Dominion shareholders is "due to the fact that evidence of environmental violations and environmental contamination is much more extensive for DEP than it was for Dominion," and because DEP is seeking to recover a higher amount of CCR costs. (Id. at 1520-21.)

At the hearing, witness Lucas[3] explained that the Public Staff had recommended that Dominion shareholders be apportioned 40% of coal ash costs, while in the present case, it was recommending that DEP shareholders be apportioned 50% of coal ash costs, because of the comparison of the records of the utilities. (Id. at 1640.) He acknowledged that Dominion had unauthorized seeps at its facilities, and that Dominion had self-reported groundwater seepage at the Chesterfield Power Station in 2018. (Id. at 1641, 1647.) He also acknowledged that Dominion had been faced with allegations of violations with respect to a hazardous substance release. (Id. at 1643-44.) In addition, he acknowledged that Dominion had entered into a consent decree that provided for injunctive relief and

[3] The live testimony of witnesses Bednarcik, Wells, Williams, Hart, Quarles, Wilson, Garrett, Moore, Riley, Junis, and Maness in Docket No. E-7, Sub 1214 was copied into the record in the current docket as if given orally from the stand, pursuant to the September 28, 2020 Amended Joint Stipulation Regarding Admission of Certain Live Testimony and Exhibits (Amended Stipulation) entered into by DEP, the Attorney General's Office, the Sierra Club, and the Public Staff.

The Amended Stipulation stated the following: "The Stipulating Parties recognize that Public Staff witness Junis appeared in the DE Carolinas case, but is not appearing in the DE Progress case, and that his place in the DE Progress case is being assumed by Public Staff witness Jay Lucas. Accordingly, in this instance, the "same" witness as Charles Junis in the DE Progress case is understood to be Public Staff witness Lucas." Amended Stipulation at 3, n 2.

Therefore, during the hearing, witness Lucas adopted the live testimony of Public Staff witness Junis in Docket No. E-7, Sub 1214, and witness Maness' live testimony in Docket No. E-7, Sub 1214 was likewise copied into the record. (Tr. vol. 15, 1633-34.) Citations in this Order to Tr. vol. 15, pages 1639-1817 reference the stipulated live testimony from Docket No. E-7, Sub 1214 of witnesses Junis and Maness.

pursuant to which Dominion was to pay a $1,400,000 civil penalty. (Id. at 1645-46.) Witness Lucas noted, however, that the complaint and consent decree pertaining to the seeps and hazardous substance release were filed in March of 2020, well after the completion of the 2019 Dominion rate case, and were therefore not before the Public Staff or the Commission for consideration in that proceeding. (Id. at 1646.) He also confirmed that Dominion had groundwater exceedances at its coal ash sites. He stated that the Public Staff had asked Dominion's regulators for information regarding Dominion's groundwater monitoring data, and testified that while both Dominion and DEP are subject to the same monitoring requirements under the CCR Rule, they are subject to different requirements under their respective state laws. (Id. at 1651-53.)

Witness Lucas testified that the Public Staff conducted a thorough investigation of Dominion, and that the Public Staff relies heavily on both the utility being investigated and the regulators to provide information. (Id. at 1647.) He indicated that the Public Staff had been unable to obtain a number of documents that it had requested during the Dominion rate case. (Id. at 1655.) He further stated that the Public Staff and the Commission are reliant on the facts before them. (Id. at 1649.) Witness Lucas testified that the Public Staff had asked Dominion about seeps, environmental compliance, and their groundwater monitoring data, and that the investigation "was exhaustive and very much replicated our investigation of Duke in their prior rate cases." (Id. at 1648.) He reiterated that, based on the available evidence, the opinion of the Public Staff is that Dominion has a better environmental record than DEP. (Id. at 1655.) On redirect, witness Lucas, having refreshed his recollection with regard to the Dominion rate case, stated that the Public Staff's testimony in that case did detail the Public Staff's knowledge of the seeps at the Chesterfield Power Plant. (Id. at 1737-39.) He further stated that in comparison to the areas of seepage at the Chesterfield Power Station, DEP and DEC together identified nearly 200 seeps. (Id. at 1739.) In addition, witness Lucas discussed in more detail the investigation that took place with regard to Dominion's environmental compliance record during the 2019 Dominion rate case, emphasizing that the Public Staff had sent follow-up discovery requests and had followed up with the Virginia DEQ. (Id. at 1741-42.) Lastly, witness Lucas characterized the comparison between the environmental compliance records of DEP and Dominion as qualitative rather than quantitative. (Id. at 1742-43.)

During cross-examination, witness Lucas was also asked about the cumulative total of exceedances that had occurred at the Company's coal ash basins, which had increased from the number of exceedances reported as of the last rate case. (Id. at 1660-61.) He was presented with a hypothetical in which DEP is required to install 49 additional wells at one of its retired, dewatered ash basins, and to sample those wells weekly over the course of a year. He was asked whether the plume was basically exactly the same as it had been, despite the significant increase in the number of exceedances because of the additional wells and increased testing frequency. (Id. at 1661-65.) Witness Lucas stated that because not all the wells would be placed on top of each other, you would now have better defined the extent of the plume in terms of shape, size, and the severity of the concentration of contaminants. He also added that because groundwater is constantly moving, you would be sampling new contaminants, rather than sampling the same column of water. (Id. at 1665-66.) He reiterated that the testing that has been conducted at DEP's facilities since the last rate case has been intended to define the extent and severity of the pollution. (Id. at 1667.) On redirect, witness Lucas stated that it would not be typical for DEQ to require testing on a weekly basis as posed in the cross-examination hypothetical. (Id. at 1745.)

During cross-examination, witness Lucas also explained his use of the term "serious risk," which he had used when he testified that the Company knew or should have known that unlined coal ash impoundments "posed a serious risk to the quality of surrounding groundwater and surface water." (Id. at 1699.) He explained that the Public Staff understands "serious" as "having important or dangerous possible consequences and risk as the possibility of loss or injury." (Id.) He added that, in the context of his testimony, serious risk means that unlined impoundments "presented a strong possibility of degrading the quality of surrounding groundwater and surface water." (Id. at 1699-1700.) With respect to the term "dangerous," he referred to the potential health impacts of exceeding the 2L standards, many of which are based on drinking water standards. (Id. at 1700.)

With respect to industry standards, witness Lucas testified on cross-examination that "given its prominence, DEC and DEP and their historic companies basically helped set industry standard," and that it is a "cyclical defense" to say that you are using the industry standard while also setting the industry standard. (Id. at 1700-01.)

Witness Lucas testified that his only recommendation regarding what DEP should have done differently is that they should have conducted comprehensive groundwater monitoring in the 1980s. (Id. at 1702.) He stated that "you cannot make any other decisions without that information." (Id.) On redirect, he added that it would have been reasonable, as a responsible utility and based on the information available, to begin groundwater monitoring earlier. (Id. at 1748.) He also testified that, although there was no strict guidance from DEQ on how to close coal ash impoundments in the 1980s, there were laws and regulations in place, such as the 2L rule, the Clean Water Act, and RCRA, that had to be adhered to and that would have likely been the guiding principles when determining proper closure. (Id. at 1708-17.)

When asked about the conclusion in the 1988 EPA report that "current waste management practices are adequate to protect the environment," witness Lucas stated that this conclusion was based on the information the EPA had at the time, and that the report stated how little groundwater monitoring was occurring at the sites that were surveyed. (Id. at 1725.) He testified that the EPA recognized this deficiency, and that is why it continued to study the issue. (Id. at 1726.)

In response to Commission questions, witness Lucas explained that culpability is based on the Company's duty to comply with environmental regulations and its failure to do so, as evidenced by groundwater violations, unpermitted discharges, and the federal plea agreement for criminal negligence, among other things. (Id. at 1749.) He stated that a prudence analysis is "nearly impossible" with the amount of time that has passed and because of the lack of information necessary to determine what the feasible alternative to any imprudent or unreasonable actions would have been. (Id. at 1749-50.) He also indicated that during discovery, DEP agreed that it would be too speculative to attempt to quantify historical costs.[4] (Id. at 1750.) He confirmed that even with unlimited time and resources, other feasible alternatives could not be determined. (Id. at 1750-51.) Witness Lucas testified that an equitable sharing is appropriate to balance the costs between shareholders and ratepayers, and that doing so is within the discretion of the Commission under N.C.G.S. § 62-133(d). (Id. at 1750.)

Witness Lucas also confirmed that the recommended 50/50 sharing was a qualitative determination based on both witness Maness' testimony and the Company's culpability for environmental noncompliance. (Id. at 1761-62.) Witness Maness added that in past Commission orders dealing with nuclear abandonment costs, the Commission imposed roughly a 30/70 sharing via a 10-year amortization with no return on rate base. He stated that the level of sharing can differ from case to case, depending on the facts and circumstances in each case. (Id. at 1762-63.) Witness Maness added that the Commission has in the past effectuated a sharing of costs between shareholders and ratepayers without a finding of imprudence on the part of the Companies. (Id. at 1773.)

In discussing the equitable sharing recommendation further, witness Lucas explained that another factor in this case is that if the Company had done something differently in the past, the costs associated with those actions would

[4] Lucas/Maness Public Staff Redirect Exhibit Number 2.

have been recovered through rates and tied to customers who actually benefitted from the electric generation. Here, however, he testified that a majority of the costs being requested for recovery are tied to previous customers but will be paid for by present and future customers. (Id. at 1811.) Witness Maness added that the costs being incurred now are the result of DEP's past actions or inactions. (Id. at 1812.)

Public Staff witness Maness testified that the Public Staff believes that an equitable sharing is appropriate and reasonable for the reasons set forth by witness Lucas, and because there is a history of approval for sharing of extremely large costs that do not result in any new generation of electricity for customers. He noted that such sharing between ratepayers and shareholders has been approved for costs of abandoned nuclear construction and for environmental cleanup of manufactured gas plant facilities. Witness Maness stated that even if the reasons for equitable sharing set forth by witness Lucas were not present, the Public Staff still believes that some level of sharing, perhaps comparable to that previously used for abandonment losses on cancelled nuclear generation facilities, would be appropriate and reasonable for DEP's CCR costs. (Id. at 1560-65.)

Witness Maness opined that there were several reasons why, independent of culpability, the magnitude and general nature of the CCR costs in this case justified equitable sharing, including the following: (1) the total amount of costs incurred during the Deferral Period ($404,684,000, on a system basis, after removal of the adjustments recommended by other Public Staff witnesses) is extraordinarily large; (2) DEP will be incurring significant additional costs in the future, in the billions of dollars; (3) much like the equitable sharings that have been approved by the Commission with regard to plant abandonments over the years, the incurrence of these costs will not provide any benefits to customers in terms of additional electric service or improvements in service; (4) unlike some situations in recent years in which plants have been retired early due to economic reasons, the incurrence of CCR costs has not been the result of an economic analysis that pointed toward an action that would be economically advantageous to ratepayers; and (5) equitable sharing helps mitigate the intergenerational inequity of present and future customers paying for costs caused by service to customers in past decades. (Id. at 1563-65.)

AGO Witness Hart discussed in detail the regulatory framework applicable to coal ash, including the CCR Rule, CAMA, the 2L rule, and regulatory determinations issued by the EPA. (Tr. vol. 13, 548-66, 571-72.) He testified that in many cases, the Company had either no background wells, the alleged background wells were too close to the waste facility, or the alleged background wells were not upgradient of the basin. He cited to a 2009 DEQ letter that identified deficiencies with regard to several background and upgradient wells at the Asheville, H.F. Lee, Cape Fear, and Roxboro facilities, and stated that no additional background wells were installed at those facilities until 2010 and 2011. He also testified that "[i]n some cases, DEP did not reliably establish or evaluate background conditions, but indicated that concentrations of metals in downgradient wells were believed to be naturally occurring when in fact they were not." (Id. at 569-70.) He also testified that the best way to determine compliance with the 2L groundwater standards is to sample at or beyond the compliance boundary, and that monitoring within the compliance boundary is intended to provide a warning. (Id. at 570.)

Witness Hart discussed the general history of coal ash impoundments and related environmental contamination. (Id. at 573-74.) He stated that coal ash has high concentrations of toxic metals and other inorganics, and that if toxic compounds such as metals are released into the environment in sufficiently high concentrations, they can pose a risk to human health and ecological receptors. (Id. at 574.) Witness Hart testified concerning the fate and transport of metals in the environment, and provided a number of factors that affect the fate and transport of metals, including the concentration and form of metal, soil properties, and properties of the groundwater. (Id. at 575-79.) He stated that "[i]n general, after a metal is released to the environment, it will accumulate in soil until the capacity of the soil to retain it is exceeded." (Id. at 576.) Once the capacity of the soil to retain the constituent is exceeded, the metal becomes mobile, migration takes place, and it enters the groundwater. Witness Hart stated that once a metal becomes soluble and mobile in groundwater, it can migrate downgradient and potentially impact receptors such as drinking water supply wells and surface waters. (Id. at 576-77.)

Witness Hart also testified regarding the types of waste streams and materials that were disposed of in DEP's coal ash impoundments over time, and the potential effects waste streams other than coal ash, such as FGD scrubber wastewater and pyrites, can have on impoundments. (Id. at 579-83, 586-88.) For example, he testified that adding other waste streams can have an effect on the "complex geochemical interactions" in the impoundments by adding other chemicals and changing pH, and that “these actions can impact contaminant loading and the fate and transport of other metals and inorganics.” (Id. at 586.) He noted an industry study that found that “pyrite can form acidic leachates (sulfuric acid) as a result of pyrite oxidation in the basins which results in higher concentrations of sulfates, and metals such as iron, nickel, and arsenic.” (Id. at 587.)

Witness Hart testified regarding the process that occurs when coal ash is placed into an impoundment and leaches into the groundwater. (Id. at 583-86.) He stated that “[o]ver time, more leachate entering the groundwater system can lead to higher groundwater concentrations and further migration distances in groundwater.” (Id. at 584-85.) Witness Hart discussed several primary factors that contribute to groundwater contamination from coal ash impoundments, including: the mass of ash and concentration of metals and other organics present in the ash, the length of time the impoundment has been in operation, the hydraulic head, and the composition of the soil underlying the impoundment. (Id. at 585-86.)

Witness Hart testified that the electric industry, including DEP, was “generally aware of the reasonable potential for leaching of metals from coal ash and associated actual or potential groundwater contamination,” citing to publications ranging from 1978 to 2009, including a 1980 report published by the EPA and the Tennessee Valley Authority, the 1988 EPA Report, and a 1991 EPRI report. (Id. at 588-95.) Witness Hart also reviewed a number of internal DEP documents with regard to actual or potential groundwater contamination from its coal ash basins and DEP’s concerns, and summarized a set of such documents ranging from 1978 to 2014. (Id. at 595-618.) For example, he discussed a 1978 letter from DEQ to the Wilmington District of the Army Corps of Engineers regarding the Draft Environmental Impact Statement conducted for the Mayo facility. According to witness Hart, the letter expressed concern with regard to groundwater contamination and the discharge of pollutants into a nearby surface water. (Id. at 596.)

Witness Hart also discussed the 1979 Mayo study, which he stated concluded that the soil at the proposed impoundment location would prevent significant leakage to groundwater and reduce concentrations of metals as the leachate traveled through the underlying soil, despite the fact that leachate tests showed increases in concentration of iron, chromium, lead, and zinc in the leachate. He added that the report recommended measures to minimize the potential for groundwater impacts and for early detection of contamination, such as periodic sampling and sealing possible leakage paths with clay, but that it is unknown whether those measures were taken. Witness Hart testified that it does not appear that any groundwater monitoring was initiated at the Mayo site until 2008, "approximately 30 years after groundwater monitoring was recommended by both DEQ in 1978 and DEP's own study in 1979." (Id. at 596-98.)

In addition, Witness Hart testified concerning correspondence regarding the Sutton facility, with documents ranging from 1984 to 1987. Specifically, in 1984, DEQ indicated to DEP that it had "very significant concerns" about groundwater impacts from a coal ash impoundment at the Sutton facility and a proposed expansion of the impoundment, and thereby requested that DEP conduct groundwater monitoring at the site. In 1986, following a review of the groundwater data that had been collected at the Sutton facility, DEQ required DEP to conduct additional groundwater assessments, and in 1987, as a result of the additional groundwater monitoring, DEQ issued a Notice of Non-Compliance to the Company for exceedances of Total Dissolved Solids and chlorides at and beyond the compliance boundary. According to witness Hart, this correspondence and the issues at the Sutton facility made it apparent that by the mid-1980s, DEP was aware that "DEQ had significant concerns about the presence of groundwater contamination from coal ash basins," that bottom liners were a potential method for minimizing groundwater contamination, and that elevated concentrations of compounds from a coal ash impoundment were a concern to DEQ and required further evaluation, even if those concentrations did not exceed groundwater standards. (Id. at 598-600.) Witness Hart testified that steps can be taken to minimize groundwater contamination at active coal ash impoundments, including: converting the facility to dry fly ash and bottom ash handling, frequently removing coal ash from the impoundment, eliminating wastewater streams and hydraulic loading from other sources, installing a liner, lowering the water level or dewatering the impoundment to reduce hydraulic load, and ultimately closing the impoundment. He indicated that all these options take time to complete and have significant costs associated with them. (Id. at 618.) Witness Hart testified that prior to CAMA and the CCR Rule, DEP had considered dry ash handling for those facilities that had not already converted to dry ash handling, and that DEP had also considered closure of its ash basins. (Id. at 619.)

Witness Hart provided a summary of groundwater monitoring data for each of DEP's facilities. (Id. at 624-85.) He concluded that by the late 1980s, as a result of groundwater concerns at the Sutton plant, DEP was aware that DEQ had concerns regarding coal ash impoundments, that liners had the potential to minimize groundwater impacts, and that groundwater impacts at or beyond the compliance boundary did occur. He also concluded that groundwater monitoring at the Robinson, Roxboro, and Weatherspoon facilities indicated contamination from the coal ash impoundments as early as the mid-1990s. He testified that by the early 1990s, DEP knew that it could decrease contamination by modifying its coal ash facilities. Witness Hart also testified that by the early 2000s, it was clear to the electric industry that EPA's documentation of damage cases and assessment of environmental impacts would lead to increased scrutiny and potential closure of impoundments. He stated that although DEP began voluntary groundwater monitoring in the mid-2000s, it did not follow the Utility Solid Waste Activities Group action plan for responding to data where groundwater impacts were detected, and that DEP submitted the data to DEQ without evaluation or responsive action. (Id. at 686-88.) Witness Hart also testified that there is evidence that the addition of FGD wastewaters to coal ash impoundments contributed to additional groundwater contamination, and that DEP was aware of this issue, but that DEP did not address the increased contamination. (Id. at 691-92.)

According to Witness Hart, exceedances of the 2L standards within or beyond the compliance boundary at the Company's North Carolina facilities, and exceedances of the maximum contaminant levels (MCLs) at the Robinson facility in South Carolina, should have triggered additional actions, such as the installation of monitoring wells at the compliance boundary, the installation of additional monitoring wells to determine the extent of impacts, and corrective action, if appropriate. He stated that the Company had instead waited for regulatory agencies to identify concerns. (Id. at 690-91.) He stated that DEP should have taken responsive action sooner and addressed its impoundments by closing out-of-use basins and converting operational facilities to dry ash handling, eliminating other wastewater streams, engaging in closure planning, and evaluating methods to reduce environmental impacts. (Id. at 692-93.) He added that it wasn't until the 2014 Dan River spill, and resulting pressure from the public and regulators, that DEP committed to full assessments, closure evaluations, dry ash handling conversions, and other closure activities on an expedited basis. (Id. at 692.) He further testified that DEP's delay in addressing groundwater contamination and closing certain out-of-use impoundments increased the costs it is seeking for CCR-related activities today. (Id. at 693-95.)

Witness Hart then discussed his proposed disallowance for the costs of providing alternate water supplies, as well as his proposed disallowance for costs for basins that he contended "should have been taken out of service long ago" at the Asheville, Cape Fear, H.F. Lee, Roxboro, and Sutton facilities. (Id. at 695-99.) He also explained his recommended adjustment in which he estimated the reduction in costs if DEP had responded earlier to the presence of groundwater impacts at its coal ash impoundments with remediation and closure activities similar to those it started in 2014 and that continue today. He further explained that his calculated costs were based on the time value of money starting at different points in time, 1992, 1996, and 2009, and that they were likely an underestimation of the potential cost reductions. (Id. at 699-702.)

Sierra Club witness Quarles testified regarding the Company's historical knowledge. With respect to the scientific community, he stated that "[t]he risks of groundwater contamination from unlined coal ash ponds were understood as early as the late 1970s," citing to a 1976 Argonne National Laboratory Report, a 1979 report by Arthur D. Little and the EPA, and a 1979 Los Alamos Report. (Tr. vol. 14, 598.) With respect to the EPA, he stated that the agency has recognized the risks to groundwater associated with coal ash disposal and the importance of groundwater monitoring since 1979, pointing to solid waste regulations under the Resource Conservation and Recovery Act (RCRA). He also cited the 1980 and 1988 EPA Reports. (Id. at 598-99.) Lastly, witness Quarles testified that the electric utility industry understood the environmental risks associated with the disposal of coal ash in unlined impoundments in the late 1970s and early 1980s, citing to the 1981 and 1982 EPRI Manuals. (Id. at 594, 600-02.)

On cross-examination, when asked if it was appropriate to take "snippets" from a historical document and present it as supporting a proposition "on which the study came to a contrary conclusion," witness Quarles responded that such "snippets . . . are important sentences that are included in the documents related to the risks associated with coal combustion waste disposal." (Id. at 638.) He further testified that context is important when reviewing such documents, stating that, for example, some of the studies cited by Company witness Williams in her testimony looked at the use of surface impoundments related to oil and gas, or municipal wastewater, and that such documents would also have language discussing areas more relevant to the surface impoundments typical of the Company. (Id. at 639-40.) He also testified on cross-examination that the 1982 EPRI Manual was meant, in part, to enable a utility to determine whether or not it was contaminating the groundwater and whether it should upgrade a facility. (Id. at 650-51.)

Witness Quarles testified that the Company's continued operation of unlined surface impoundments without adequate groundwater monitoring for decades after the industry recognized the risks associated with such operation was unreasonable and could be expected to result in the introduction of coal ash constituents in surface water and groundwater. (Id. at 594, 615-16.) He stated that disposal options that could lessen the risks associated with coal ash disposal, such as dry ash handling systems, conversion of impoundments to landfills, and the use of liners, were available in the 1980s, and that liners were the rule by the 1990s. (Id. at 602-03.)

Witness Quarles discussed soil attenuation and explained that it does not protect against the migration of coal ash constituents over the long term, as soil attenuation capacity can be exceeded. He also explained why information about the ability of soil to attenuate contaminants at one site does not support a conclusion at a different site, as "[t]he ability of soil to attenuate contaminants is based upon numerous waste and site-specific geologic, hydrogeologic, and geochemical factors." (Id. at 610-12.)

Witness Quarles testified that the Company first became aware of impacts from its coal ash impoundments when investigations took place in the 1970s. He discussed the 1979 Mayo study, which concluded that a one-foot clay liner would be necessary for the proposed coal ash impoundment in order to protect groundwater. He explained, however, that the report concluded that even with such a liner, "not all metals would be filtered, and the duration of the filtering would be limited." (Id. at 607-08.) Witness Quarles also testified that a facility located near the coal ash impoundment at the Sutton plant reported elevated concentrations of chloride in groundwater, and that in response, DEP performed groundwater sampling and determined that its new impoundment should be constructed with a liner. (Id.)

With regard to the 1985 Arthur D. Little Report, witness Quarles testified that the testing showed that arsenic concentrations in groundwater beneath DEC's Allen site exceeded drinking water standards. He stated that the report "[n]evertheless" concluded that "impacts were expected to be 'insignificant,' apparently looking only at impacts to the adjacent surface waterbody but not to groundwater quality." (Id. at 608-09.) Witness Quarles noted several reasons why the 1985 Arthur D. Little Report did not support a decision to not conduct groundwater monitoring at DEP's coal ash sites. For example, he stated that the report "acknowledged that steady-state groundwater conditions at the Allen site had not yet been reached in downgradient groundwater monitoring wells—meaning that the full contaminant plume had not yet reached downgradient wells and contamination concentrations could get much worse." (Id. at 609.) In addition, he stated that "the report concluded that increasing constituent concentrations in downgradient wells 'would be expected,'" and that "available data 'cannot support a precise estimate of future groundwater quality.'" (Id.) Witness Quarles added that the report did highlight the potential threat to groundwater from coal ash impoundments and document existing contamination and the risk of downgradient contamination increasing over time. (Id.)

Witness Quarles explained that the Company began voluntary monitoring of groundwater at the Cape Fear and H.F. Lee facilities in 2007 and at the Mayo facility in 2008. He also testified that DEQ first required monitoring at Sutton in 1984, Roxboro in 1986, and Weatherspoon in 1989. He stated that it was unreasonable for the Company to operate unlined coal ash impoundments for decades without monitoring groundwater quality, as the industry was well aware of the risk of environmental contamination, and the Company was aware of leaching at the Sutton site in the early 1980s. He stated that "[t]he only prudent option for learning whether a given ash basin was causing contamination of water resources was to install and sample monitoring wells." (Id. at 605-06.)

According to witness Quarles, "[t]he only prudent option for learning whether a given ash basin was causing contamination of water resources was to install and sample monitoring wells." (Id. at 606.) He testified that the construction or expansion of unlined coal ash impoundments after the mid-1970s was unreasonable. Witness Quarles also testified that the continued operation of unlined coal ash impoundments after the 1980s was unreasonable. He argued that "[t]he ample information available to the Company regarding the risks associated with unlined disposal unit operations should have led the Company to begin to transition away from wet handling and disposal of coal ash much sooner," and that "at the very least," the Company should have begun groundwater monitoring much sooner than it did. (Id. at 615-16.) He stated that the Company did not operate adequate groundwater monitoring systems until the 2000s. (Id. at 615.)

With regard to the impacts of DEP's unlined impoundments, witness Quarles testified that coal ash is impacting the groundwater at each of the Company's facilities, and that contamination has migrated off-site at several facilities. He stated that in numerous cases, rather than taking action to eliminate or mitigate the contamination, DEP has instead purchased affected properties or provided alternative drinking water sources. (Id. at 616-20.) Witness Quarles then discussed in detail groundwater contamination at the Company's Sutton facility. (Id. at 616-20.) He also testified that the costs associated with excavation and groundwater monitoring would have been lower if DEP had converted its facilities to dry disposal in lined landfills sooner. (Id. at 621.) Witness Quarles summarized his testimony by stating that DEP's "inaction resulted in more widespread contamination of the state's groundwater resources, jeopardy to present and future drinking water sources, the need for alternative drinking water supplies, and millions of tons more ash to be dewatered, excavated, and redisposed of, all driving higher cleanup and risk reduction costs." (Id. at 627.)

CUCA witness O'Donnell testified that the North Carolina legislature passed CAMA in 2014 in response to the Dan River Spill. (Tr. vol. 14, 168-69, 171-73.) He stated that on May 14, 2015, DEC, DEP, and Duke Energy Business Services pled guilty to nine violations of the Clean Water Act, including unauthorized discharges of pollutants from its coal ash basins via seeps into adjacent surface waters. (Id. at 169-70.) Witness O'Donnell also testified that CAMA is more stringent than the CCR rule. (Id. at 173.) He stated that he disagreed with Duke's position that consumers should pay all the costs of coal ash cleanup, and stated that "Duke management made specific decisions that resulted in the coal ash spill in North Carolina that, in turn, led to the creation of [CAMA]." (Id. at 176.) He recommended that DEP not be allowed to recover coal ash costs associated with any plant that is not subject to the federal CCR Rule but is subject to CAMA. He further recommended that to the extent any site is no longer receiving coal ash, remediation costs should not be paid for by ratepayers in this case or any future cases. (Id. at 178.) In summary, witness O'Donnell testified that the Commission should disallow the incremental costs associated with CAMA versus the federal CCR Rule. (Id. at 133.)

DEP REBUTTAL TESTIMONY

In her rebuttal testimony, witness Bednarcik updated her direct testimony to note that on December 31, 2019, the Company entered into a settlement agreement (Settlement Agreement) with DEQ and a number of environmental groups. She explained that the Settlement Agreement provides for closure of the nine remaining CCR basins owned by DEP and DEC. Seven of the nine basins—including one at the Mayo Plant and one at the Roxboro Plant—will be excavated and the ash moved to on-site lined landfills. For the other two basins, including one at the Roxboro Plant, uncapped basin ash will be excavated and moved to lined landfills. Witness Bednarcik noted that the Settlement Agreement calls for expedited state permit approvals, keeping projects on a rapid timeline and reducing the total estimated cost to close the remaining basins by roughly $1.5 billion as compared to the April 1, 2019 DEQ order requiring full excavation at all sites. (Tr. vol. 17, 84.)

In response to the Public Staff's recommended 50/50 equitable sharing disallowance, witness Bednarcik pointed out that the recommendation is not tied to any finding of unreasonableness or imprudence, but to culpability for environmental degradation requiring expensive remediation and the enormity of the costs. (Id. at 136.) She noted Public Staff witness Lucas' admission of the impossibility of conducting a prudency audit of the Company's historical CCR activities. (Id.) Witness Bednarcik stated that the Commission has rejected this equitable sharing approach three times, and that in the 2017 rate case, as in this case, the Public Staff was unable to quantify any discrete cost throughout the Company’s history managing CCR that was deemed to be imprudent or connected to an imprudent action. (Id. at 137-38.)

Witness Bednarcik also responded to the contentions of witnesses Lucas, Hart, and Quarles that the Company's CCR practices lagged behind those of industry, contending that the Company’s historical CCR practices were in line with those of industry and similarly situated utilities in neighboring states. (Id. at 138-39.) In response to the historical documents cited by witnesses Lucas, Hart, and Quarles, witness Bednarcik argued that this “small handful of papers” would not have given a utility adequate reason to change its CCR practices. (Id. at 138.) She testified that “[i]n an apparent attempt to cast doubt over DE Progress’ use of unlined basins, Mr. Lucas, Mr. Hart, and Mr. Quarles cite a small handful of papers published between 1967 and 1985 which discuss potential issues associated with coal ash disposal and the importance of developing and implementing appropriate controls.” (Id.) She further testified that “the publications do not provide sufficient, if any, conclusions or certainty to prompt a utility to undertake the costly effort of changing its storage practices.” (Id.)

In response to witness Lucas' statistics on the use of lined impoundments in the 1988 EPA Report, witness Bednarcik noted that DEP last constructed a new ash basin in 1985. She noted that witness Lucas failed to account for site-specific conditions, which is an essential consideration, and she argued that he presented no credible evidence to show that DEP’s engineering and design of its impoundments was not consistent with industry practice and regulatory requirements at the time. Witness Bednarcik contended that the intervenor witnesses were viewing these issues “through the filter of a 21st century lens when no such clarity existed in real time.” (Id. at 138-39.)

Witness Bednarcik also disagreed with the assertion that the Company should have constructed lined units instead of expanding the existing unlined impoundments, pointing to the expense, the need to maintain the existing unlined ponds, the inconsistency with then current industry practices, and the risk of disallowance of the cost. (Id. at 140, 146.) Based on a review of the report and materials presented by DEP witness Bonaparte analyzing coal-fired plants in South Carolina, Virginia, and Georgia, witness Bednarcik indicated that only six of the 63 CCR impoundments identified in the report were lined. (Id. at 139.) In addition, she stated that of the 58 impoundments constructed in or before 1985, the year that a basin was constructed at Cape Fear, only two were lined. Thus, witness Bednarcik concluded that the Company's practices were similar to those of utilities in neighboring states. (Id.)

Witness Bednarcik testified that she did not believe the costs to build new lined impoundments to retire existing coal ash impoundments would have been recoverable in rates before the enactment of the CCR Rule and CAMA. (Id. at 140.) She contended that before the CCR Rule or CAMA, there was no justification for the Company to change its practices, which had "always been in compliance with existing state and federal laws." (Id. at 140, 143.) She also noted that no regulator or intervenor had suggested a change in the Company's historical practices. (Id. at 140-41.)

With respect to the testimony of CUCA witness O'Donnell, witness Bednarcik noted that the arguments made in his testimony were the same offered by him in the 2017 rate case. Witness Bednarcik adopted and incorporated by reference the rebuttal testimony of DEP witness John Kerin in that proceeding on the issues and arguments made by witness O'Donnell, stating that "[b]ecause [witness O'Donnell's] arguments are unchanged from the 2017 case, the Company's response to it is likewise unchanged." (Id. at 145.)

Witness Bednarcik addressed the recommended disallowance of AGO witness Hart and argued against his suggestion that the Company could have reduced costs by beginning closure at an earlier date. According to witness

Bednarcik, it is impossible to predict with any certainty what type of approach DEP would have pursued historically with respect to its coal ash basins given the then-existing regulatory landscape, available technology, evolving industry best practices, and other factors. (Id. at 142-45.)

Witness Bednarcik also filed supplemental testimony responding to the Commission's July 23, 2020 Order Requiring Duke Energy Carolinas, LLC and Duke Energy Progress, LLC to File Additional Testimony on Grid Improvement Plans and Coal Combustion Residual Costs. In addition to providing additional information regarding costs associated with closure of the Company's coal ash impoundments, witness Bednarcik discussed the Settlement Agreement the Company reached with DEQ and environmental groups on December 31, 2019. She explained that a key premise of the Settlement Agreement was that the parties agree that "closing the CCR impoundments at the Allen, Belews Creek, Cliffside, Marshall, Mayo, and Roxboro Steam Stations in accord with this Agreement . . . is reasonable, prudent, in the public interest, and consistent with law." (Id. 148-54.)

Witness Bednarcik also responded to the Commission's question regarding the Company's ability to estimate the incremental costs of excavating, rather than capping-in-place, remaining ash at the Company's designated "low-risk" CCR impoundments. She explained that the Company did not incur any incremental cost as a result of the Settlement Agreement with respect to the costs it is seeking to recover in the instant rate case, except that "the costs the Company incurred to prepare plans for closure by excavation were approximately $140,000 to $480,000 more per site than the costs it incurred to prepare plans for closure by cap-in-place.” (Id. at 155.) She noted that all of the site work performed for which costs are included as part of this rate case would also be required for closure by excavation. According to witness Bednarcik, “[i]t is impossible to identify with any degree of certainty the incremental costs that the Company is likely to incur as it proceeds to excavate, rather than cap-in-place, the CCR basins at Mayo and Roxboro” under the terms of the Settlement Agreement. (Id.)

DEP witness Wells testified with regard to whether the Company knew or should have known about the risks of coal ash impoundments to groundwater. He stated that unlined coal ash impoundments were the accepted approach when DEP constructed its basins, and that the construction of and continued use of the basins was reasonable and prudent. In support of his argument, witness Wells cited to Commission orders in the last DEP and DENC rate cases that found that unlined basins were a generally accepted method of disposal in the past. (Tr. vol. 19, 141-42.)

Witness Wells testified that “[c]ertainly, the Company and its environmental regulators were aware that surface impoundments, whether lined or unlined, had the potential to impact surrounding groundwater and surface water in the 1980s.” (Id. at 144.) He added, however, that he did not believe that the general knowledge of potential for impacts equates to whether the impoundments actually posed a significant risk to human health or the environment. He stated that “[w]hat was also widely accepted at the time was that most impacts were insignificant, if they had materialized at all, and largely depended on regional and other factors.” (Id.) Witness Wells testified that measures such as removing unlined basins from service, constructing alternate wastewater treatments systems, converting to dry fly ash and bottom ash handling, building solid waste landfills, installing groundwater monitoring well networks at all sites, and immediately taking corrective action would not have been a "proportionate" response to a potential risk, especially given the "evolving body of scientific knowledge." (Id. at 144-45.)

Witness Wells argued that the intervenors "cherry-pick[ed]" statements from historical documents to advance their arguments, and that their testimony lacked context. (Id. at 146.) For example, witnesses Lucas, Quarles, and Hart cited to the 1979 report written by Arthur D. Little and the EPA. While witness Wells conceded that the report identifies potential risks associated with CCR impoundments, he asserted that the paper is clear in its conclusion that environmental impacts should be evaluated on a case-by-case basis and are dependent on site-specific factors. He also testified that the follow-up to the 1979 report, the site-specific evaluation at DEC's Allen facility and other non-DEP sites known as the 1985 Arthur D. Little Study, found that no "major" environmental effects had occurred at any of the sites. (Id. at 146-47.)

When asked about the 1985 Arthur D. Little Study on cross-examination, witness Wells stated that the testing showed that "[t]here are some values that exceed what were the background -- what were the published standards for various contaminants, including manganese and iron, which have a naturally occurring contribution." (Id. at 376.) He added that at the time, background levels had not been established. He stated that the report was concluding that there was no downgradient migration of those contaminants above the drinking water level standard, “with a real focus on the primary MCLs, and even more specific to arsenic.” (Id.) He also testified that the report was trying to determine whether the contaminants could reach a receptor or present a risk to public health or the environment. (Id.) He added that “we’re not in violation of the [groundwater standards] until we begin to see an impact outside the compliance boundary.” (Id. at 385.)

Witness Wells was also asked about the findings in the 1985 Arthur D. Little Study that certain tracer constituents were at elevated concentrations versus background concentrations at the downgradient wells. (Id. at 378.) Witness Wells responded that those were naturally occurring elements that were not being regulated in the early 1980s for potential to impact public health, but rather for aesthetic reasons and other concerns. (Id. at 379-80.)

With respect to the 1981 EPRI Manual discussed by intervenors, witness Wells stated that the document was designed to aid with the development of new CCR facilities, and that it did not call for the removal or closure of existing, unlined coal ash impoundments. He added that DEP’s practices were consistent with the 1981 EPRI Manual because the Company did not construct unlined ash basins after the early 1980s. With respect to the 1982 EPRI manual referenced by intervenors, witness Wells argued that “[w]hile the 1982 manual does provide alternatives to the use of surface impoundments, it does not recommend immediate changes to site waste disposal practices.” (Id. at 148.)

DEP witness Wells testified that the Public Staff took a similar position in the DEP 2017 Rate Case when it proposed an equitable sharing of CCR costs, which would have resulted in a 50% disallowance of deferred CCR costs. (Id. at 137.) He noted that the Commission, however, did not accept the Public Staff's argument in that case. (Id., citing 2017 DEP Rate Case Order at 178-83.) Witness Wells also testified that the Public Staff offered a similar argument for equitable sharing proffered by witness Lucas in the DENC 2019 Rate Case and the Commission similarly did not adopt the Public Staff's argument in that case. (Id. at 138, citing 2019 DENC Rate Case Order at 94-95.)

Witness Wells asserted that intervenors have relied on "hindsight bias" to state that either (a) the Company knew or should have known about the risks of unlined impoundments, or (b) the Company should have conducted more comprehensive groundwater monitoring, should not have used ash basins to treat other site-generated wastewaters, should have converted to dry ash handling, should have ceased using the unlined ash basins, or should have taken some other unspecified corrective action in response to environmental impacts. (Id. at 140-41.)

Witness Wells asserted that even before CCR impoundments were regulated by the EPA and state environmental regulators, state utility regulators "were well aware of, and allowed, the continued use of unlined ash basins to store CCR." (Id. at 143.) He further asserted that, "[f]rom 1967 until 2009, the Commission had the sole authority to regulate utility dams, including all of the dams that formed DE Progress' ash basins." (Id.) In support of his assertion that the Commission actively allowed the operation of CCR impoundments, witness

Wells cited to Docket No. E-100, Sub 23, in which the Commission received and reviewed inspection reports of the ash basins every five years. (Id.)

Witness Wells argued that the Company took measured steps to assess risks. State-level regulations regarding groundwater did not come into effect in South Carolina until 1977 and in North Carolina until 1979. (Id. at 160.) In 1978, the Company initiated a groundwater study at Roxboro to evaluate impacts to groundwater from its 12-year-old coal ash impoundment. Witness Wells testified that "[w]ith the exception of zinc and copper, all tested constituents were below the limits of detection," and that the results of the testing showed that the naturally-occurring clay soils in the region "can give essentially complete protection against the trace elements that occur in ash pond sludge." (Id. at 152.)

In addition, in 1979, DEP commissioned a study to evaluate potential groundwater impacts from a proposed impoundment at the Mayo plant. Witness Wells disagreed with the intervenors' assertion that the 1979 investigation at the Mayo facility should have alerted the Company to the fact that its coal ash impoundments posed a significant risk that would have justified "aggressive actions." He stated that the 1979 report supported DEP's decision to construct an unlined coal ash impoundment at Mayo in 1983. He further stated that "[d]ue to the nature of the soils in the region, the engineering firm hired to conduct the study concluded that the proposed ash basin at Mayo would have no significant adverse impact on groundwater." (Id. at 149-50.) He added that, contrary to witness Hart's testimony that it was unknown whether the Company followed the recommended measures in the Mayo report, publicly available records show that design and construction documents for the impoundment included a specification for sealing rock outcrops with impervious soil. Witness Wells stated that this "demonstrates that DE Progress was responsive to DEQ's concerns and devoted the necessary resources to investigate a site before constructing the ash basin at Mayo." (Id. at 151.)

In summary, witness Wells testified that the studies at Roxboro and Mayo in the late 1970s indicated to the Company that its unlined coal ash impoundments "did not pose a substantial threat to groundwater quality or human health." (Id. at 160.) He also stated that the Company would have been aware of the monitoring conducted at DEC's Allen facility, which was representative of the Piedmont region. (Id. at 161.) He testified that based on the Company's internal studies, the Arthur D. Little study, which included DEC's Allen plant, the 1988 EPA Report to Congress, and the 1991 EPRI Study, "it was reasonable for the Company to conclude that continuing wet disposal of coal ash would have no significant impact on groundwater at DE Progress sites." (Id. at 162.). Witness Wells stated that the environmental regulators at DEQ and DHEC issued NPDES permits and, consistent with DEQ's phased approach to implementing groundwater monitoring assessments, groundwater monitoring was not required at all sites at the same time. (Id. at 159-60.)

During the hearing, witness Wells was asked about the studies at the Roxboro and Mayo facilities. He confirmed that the Roxboro study consisted of "two or three" downgradient wells, "some upgradient monitoring," and off-site monitoring, and that the coal ash impoundments at the Roxboro facility had been in operation for approximately 12 years and 5 years, respectively, at the time the testing took place. (Id. at 667-71.) With respect to the Mayo study, he acknowledged that the report stated that 12 test holes were finished as observation wells so that periodic sampling of the groundwater could take place. He further acknowledged that the report stated that "[t]his was to allow for the detection of trace elements in the groundwater if contamination should occur in the future." (Id. at 672-73.) When asked if any testing was conducted subsequent to the study to test for trace elements, witness Wells stated that he did not know, but that surface water sampling did take place as required under the facility's NPDES permit since 1982. (Id. at 674-75.) Lastly, with respect to the Mayo study, witness Wells was asked about the study's statement that when testing was conducted to determine where the water table was, the water table was at its lowest or near its lowest levels of the year. He responded that he did not know if that was the case, but that he was "sure it would vary by year." (Id. at 676.)

Witness Wells disagreed with witness Hart's testimony that, based on correspondence concerning the Sutton facility, the Company was aware by the mid-1980s that DEQ had significant concerns about groundwater contamination. He stated that he disagreed with the "implication that DEQ viewed the unique facts that faced the Company at Sutton as being representative of the entire fleet," and that witness Hart had overstated DEQ's concerns. (Id. at 152-53.) He also disagreed with witness Hart's testimony that, based on the same correspondence, DEQ was aware by the mid-1980s that liners were a potential method for minimizing the potential for groundwater contamination, and that elevated concentrations of compounds that did not exceed groundwater standards were still of concern to DEQ and needed to be evaluated further. (Id. at 152-57.)

Witness Wells provided a history of groundwater monitoring requirements and findings from DEQ regulators starting in the 1980s through the passage of CAMA. DEP began groundwater monitoring at the Sutton facility in 1984, and was required in its NPDES permits to conduct groundwater monitoring at Sutton and Weatherspoon beginning in 1990. In 2000, DEQ allowed DEP to “temporar[ily]” cease groundwater monitoring at the Weatherspoon facility. The Company also began voluntary groundwater monitoring at its Roxboro facility in 1987. Witness Wells testified that for the remaining sites, the Company began voluntary groundwater monitoring around 2006. He stated that the monitoring indicated exceedances of groundwater standards, but that the exceedances were primarily of “standards associated with naturally occurring conditions—iron, manganese, and pH.” (Id. at 162-63.) He also stated that following the Tennessee Valley Authority dam failure in 2008, DEQ began adding groundwater monitoring requirements to NPDES permits as they were reissued or modified. In 2011, DEQ issued a policy memo for identifying exceedances and developing corrective action plans. (Id. at 163-64.)

Witness Wells asserted that DEQ, which possessed the authority to require groundwater monitoring at any time after 1984, first added monitoring requirements to the Company’s NPDES permits in 1990, and did not require groundwater monitoring in all the Company’s NPDES permits until 2010. He argued that it is not reasonable for Public Staff witness Lucas to assert that the

Company should have implemented groundwater monitoring at all of its sites in the 1980s. (Id. 165-66.) He added that the intervening witnesses' "hindsight positions are flawed because they do not provide sufficient standards or guidelines with which to establish what type of monitoring program should have been established." (Id. at 167.)

Witness Wells further asserted that no intervenor identified with enough specificity discrete actions or omissions that constitute mismanagement by the Company. Instead, witness Wells argued that the intervenor witnesses were attempting to substitute hindsight for the judgment of environmental regulators specifically charged with such oversight. (Id. at 172-74.) Witness Wells asserted that it would not have been reasonable to take drastic remedial measures in the past. In response to whether the Company should have converted to dry ash handling earlier, witness Wells cited to the EPA effluent limitations guidelines developed in November 1982, with regard to which the EPA had stated that "the high cost of retrofitting [did] not justify the additional pollutant reductions." (Id. at 177.) Witness Wells stated, however, that in one instance, the evidence warranted conversion to dry ash handling prior to the promulgation of EPA regulations in 2015: Roxboro converted to dry ash handling in the late 1980s as part of an effort to address surface water quality impacts at Hyco Lake. (Id. at 178.)

With regard to whether the Company should have ceased using or closed its unlined basins at an earlier date, witness Wells stated that there was no environmental impetus to do so. He asserted that "the regulatory uncertainty created by the EPA's draft CCR Rule in 2010 meant that closure before 2014 would have been premature and financially irresponsible." (Id. at 180.) Witness Wells further asserted that neither DEQ nor DHEC ordered DEP to cease using or close any impoundments prior to 2014, nor did they require DEP to retrofit any existing impoundments with liners, close any impoundments no longer receiving CCR, or excavate CCR from existing impoundments. (Id. at 181.)

Witness Wells disagreed with witness Lucas' conclusion that the existence of groundwater exceedances beyond the compliance boundary are the result of the Company's mismanagement of its coal ash basins. Witness Wells asserted that the Company has taken every action required by state environmental regulators to address groundwater impacts as they have been identified. (Id. at 183-84.) Additionally, with regard to seeps, witness Wells stated that seepage is common, expected, and necessary to maintain the stability of an earthen dam. Witness Wells testified that DEQ and the Commission were aware of seeps from the Company's impoundments since well before the CCR Rule and the passage of CAMA, and that DEQ did not consider them to be a priority for NPDES permitting. (Id. at 186-87.)

With regard to witness Lucas' testimony that the number of violations for groundwater exceedances has increased since the 2017 Rate Case, witness Wells stated that the number of exceedances, even if they constitute violations of the 2L rules, are not indicative of mismanagement or imprudence. Witness Wells testified that the closure of all its coal ash basins was triggered before the 2017 Rate Case and that the triggering factor was not groundwater impacts. Witness Wells argued further that witness Lucas' testimony that DEP's compliance record has gotten worse since 2017 and that there is more evidence of violations is misleading because the violations he cites are the result of more intensive monitoring, the installation of new wells, and changed compliance boundaries since 2017. (Id. at 191.) Witness Wells asserted that by quantifying the groundwater violations as a representation of groundwater contamination, "[witness Lucas] seeks to punish the Company for prudently meeting its CCR Rule and CAMA obligations to collect groundwater samples to characterize groundwater impacts." (Id. at 192.) With regard to witness Lucas' comparison of the compliance records of DEP and DENC, witness Wells argued that "DE Progress' compliance record could have been improved if DE Progress had done a poorer job with recordkeeping or performed less comprehensive monitoring." (Id. at 193.) He continued by asserting that a direct comparison of environmental records is "clearly inappropriate" and fails to justify that DENC has a better compliance record. (Id. at 194.)

Witness Wells stated that since 2017, DEP has made substantial progress to address seeps and groundwater impacts around its coal ash impoundments. For example, it has addressed seeps through NPDES permits and Special Orders by Consent with DEQ, and has submitted closure plans and corrective action plans and entered a settlement agreement with DEQ and environmental groups. (Id. at 194-95.) Witness Wells stated that "[a]fter the passage of CAMA and even with decades of earlier data, it took DE Progress and DEQ over five years of sustained effort to decide what kinds of information were necessary to support decision-making, and to collect the information and present it in the form of corrective action plans." (Id. at 197.) He added that DEP has been successful in its efforts toward closure of its coal ash impoundments and groundwater assessment and corrective action because "it had a clear mandate in the CCR Rule and CAMA, dedicated and skilled employees, effective regulators in DEQ and DHEC, and financeable and regulatory stability." (Id.)

During the evidentiary hearing, witness Wells was asked about the conclusion in his pre-filed rebuttal testimony that the Company did not have evidence in the 1980s of significant impacts resulting from its unlined ash ponds. He confirmed that there was no groundwater monitoring at Asheville, Cape Fear, Mayo, or H.F. Lee until the 2000s. He asserted, however, that studies were performed at Roxboro in 1978, followed by the Mayo study and the installation of groundwater monitoring wells at the Sutton plant in the 1980s. He added that the Company in the 1980s was conducting surface water monitoring pursuant to its NPDES permits, which would have captured some impacts to groundwater and surface water. He added that geological considerations came into play as well, and that the conclusions in the Allen study that were associated with the Piedmont region would have been relevant to sites that did not have early monitoring. (Id. at 664-67.)

At the hearing, Witness Wells also testified that the installation of pollution control devices such as scrubbers changed the nature of the waste stream being disposed of in the basins. (Id. at 446-47.) Witness Wells further testified that any changes in the waste stream would have been looked at continuously, and reviewed and approved by regulators on a five-year cycle consistent with the water discharge permit. (Id. at 447-48.)

Witness Wells was asked at the hearing about the Commission's authority over dam inspection reports from 1967 to 2009. In response to questions about the nature of the reports made to the Commission, witness Wells conceded that they were intended to assess dam safety and integrity, and that they were not intended to be water quality inspections. He acknowledged that the authority to regulate water quality during this time remained the purview of DEQ. (Id. at 450-51.)

With regard to constructed seeps and toe drains, witness Wells was asked whether state law prohibited discharges into waters of the state without a permit and whether the engineered seeps constructed as part of the dam were authorized in any of the Company's NPDES permits. Witness Wells opined on whether seeps were point sources carrying pollutants to waters of the United States, and stated that from the 1970s until today, there has been an evolution of what a point source is under the Clean Water Act. (Id. at 453-54.) He asserted that when the EPA's 2010 Hanlon memo indicated that the seeps may be subject to permitting, Duke invited DEQ to its sites and told DEQ that permitting the seeps would be an appropriate step, and that the agency disagreed. (Id. at 454-55.) He further stated that DEQ believed at that time that permitting seeps was not a priority and revisited that decision in 2014. (Id. at 456.)

With regard to their non-constructed seeps, witness Wells testified that in 2014, when DEC and DEP admitted to having over 200 seeps, as detailed in the 2015 Joint Factual Statement (Hart Exhibit 3), there was no regulatory clarity on the permissibility of those types of seeps. Witness Wells stated that DEC and DEP took steps to survey the sites and identify areas of wetness, and that those areas of wetness may not actually be seeps, and could be seasonal, stormwater, or wetlands, or may not contain constituents from the impoundments. (Id. at 459-61.) Witness Wells conceded that even if seeps are seasonal, they can still be unauthorized discharges if they are unpermitted. (Id. at 464.)

At the hearing, witness Wells was asked about the assertion in his pre-filed rebuttal testimony that during the period from 1967 to 2009, when the Commission had authority to regulate dam safety, "[n]ot once during that time did the Commission or the Public Staff ever determine or opine that the continued use of surface impoundments to store CCR was imprudent." Witness Wells was asked specifically whether he understood the role of the Public Staff to investigate the reasonableness of rates charged by public utilities. Witness Wells replied: "I'm not familiar with the Public Staff's specific role. I would agree with that. But I understand they look at a lot of things to understand whether they agree with the costs and the rates that the Company has applied for." (Id. at 466.) He stated that, from a dam safety perspective, the Commission was involved, regulators were involved, and Duke was not operating in a vacuum. (Id. at 467-68.) However, witness Wells conceded that the Company is ultimately responsible for management of coal ash and the Company's environmental compliance. (Id. at 469.)

The rebuttal testimony of DEP witness Williams provided an overview of the federal government's study and regulation of CCRs, as well as an overview of North Carolina laws and regulations pertaining to CCRs. She started with an overview of coal ash regulation prior to the passage of RCRA and proceeded to explain the evolution of coal ash regulation after RCRA had been enacted. She also discussed effluent guidelines under the Clean Water Act, the Water Infrastructure Improvements for the Nation Act, CAMA, and the 2L rules. (Id. at 217-33.)

Witness Williams testified regarding historical knowledge about the environmental impacts of coal ash storage in unlined impoundments. She stated that in order to assess the level of knowledge at a particular point in time, one must evaluate the "weight of evidence" available at the time, "not only a limited number of isolated reports, or parts of those reports, that discuss some 'potential' for risk." (Id. at 279-80.) She defined the "weight of evidence" as "the integrated assessment of available information and data on a given topic." (Id. at 275, fn 95.) Witness Williams testified that, "[w]hen considering available knowledge, it is important to include not only the knowledge of [DEP] but also the knowledge and actions of government public health and environmental officials . . . ." (Id. at 274.) She stated that in her opinion, the intervenors selectively referred to various documents without weighing the broader set of available knowledge at the time. She also stated that the intervenors appeared to downplay or overlook the role of regulations, and that the fact that neither the use of liners nor the installation of groundwater monitoring systems was mandated by state or federal regulations was an important factor in assessing the reasonableness of DEP's historic activities. In addition, witness Williams testified that the intervenors failed to assess the state of industry practices at the time. (Id. at 274-76.)

According to witness Williams, the EPA in 1993 determined that the risk from coal ash management did not warrant the establishment of regulations that would have modified the manner in which DEP was managing its coal ash. She added that the EPA based this determination on its review of available information, including the reports from the late 1970s to early 1980s that were cited by intervenors. She testified that the EPA's 1993 determination was made after a review of state regulatory authorities, and with the knowledge that most surface impoundments were unlined and did not have groundwater monitoring. She added that if the knowledge about potential groundwater contamination was as well understood as intervenors contended by the early 1980s, there would not have been such a high percentage of industrial surface impoundments and oil and gas waste impoundments operating without liners and groundwater monitoring as of the mid-1980s. (Id. at 281.) Similarly, she testified that the use of liners and groundwater monitoring was not common for coal ash impoundments and other industrial surface impoundments, citing the 1988 EPA Report, a 2001 EPA report entitled "Industrial Surface Impoundments in the United States," and the 2010 Proposed CCR Rule. (Id. at 282-83.)

Witness Williams also provided testimony specifically addressing the historical documents cited by the intervenors. (Id. at 284-91, 299-303.) For example, she discussed the 1979 Arthur D. Little Report and asserted that it "does not conclude that all ash ponds should be lined or that all ash ponds require groundwater monitoring to prevent environmental harm to groundwater." (Id. at 285.) She also discussed the 1981 EPRI manual, stating that intervenors' use of the document as a basis to argue that leachate from coal ash impoundments is of concern due to the possibility that heavy metals can enter the groundwater and contaminate drinking water "is a relatively weak statement, indicating the absence of data and knowledge, not the certainty of it." (Id. at 286.) She added, in addition to other critiques, that the document was written as guidance for new disposal facilities and was not applicable to existing operating facilities. (Id.) She also disagreed with the intervenors' assessment of the 1982 EPRI Manual, stating that it found that it may be premature for any utility to update its existing disposal facilities, and that the manual relied heavily on federal documents that were mis-cited. (Id. at 287-88.) With respect to the 1985 Arthur D. Little Study, witness Williams stated that the report concluded that no major environmental effects had occurred at any of the six sites in the study, including DEC's Allen facility. (Id. at 288.)

Witness Williams testified that "[v]irtually any waste management unit, regardless of its design or operational practices, has the 'potential' to release constituents to groundwater under some circumstances." (Id. at 297.) She added that "asserting that DE Progress knew ash ponds generally had the 'reasonable potential,' however defined, to contaminate groundwater, even if true, does not tell you anything about what DE Progress did or did not know about the likelihood for any particular ash pond it operated to contaminate groundwater at levels that were understood, at the time, to equate to environmental harm." (Id. at 297-98.) Witness Williams contended that "despite the existence of some literature that may point to a 'potential' for land disposal of waste to result in environmental harm, there was not a general awareness that most unlined ash ponds would result in environmental harm to groundwater." (Id. at 304.) She then discussed a general lack of information about industrial waste management and the subsurface environment "well into the 1980s." (Id. at 305-06.)

On cross-examination, witness Williams stated that "the knowledge at the time was not sufficient to say those coal ash basins were understood that they were going to result in contamination of groundwater above 2L standards or above health protective levels." (Id. at 352.) She further disagreed that the EPRI manuals represented the state of industry knowledge at the time. (Id. at 358-62.) She added, with regard to both the 1981 and 1982 EPRI Manuals, that EPRI was "just trying to share the information as to what could potentially be happening," and that while the manuals did state that groundwater monitoring was "necessary to provide convincing proof of a safe disposal practice," groundwater monitoring was not required by federal regulations or any of the Company's permits. (Id. at 360, 363.) Witness Williams testified that the EPRI manuals "didn't represent either industry standards or what ultimately was deemed necessary to happen to protect groundwater at that time based on information at that time." (Id. at 362-63.) She also stated that after the 1981 EPRI manual was issued with guidance on groundwater monitoring, the EPA realized the guidance was "naïve" and not capable of easily being translated in complex situations. (Id. at 366-67.) She added that the EPA released its own guidance manual for groundwater monitoring in 1986, which it updated in 1992. (Id. at 367-68.)

Witness Williams argued that DEP acted properly in its management of coal combustion residuals. She stated that until the passage of CAMA and the promulgation of the CCR Rule, operators of coal ash basins faced uncertainty with regard to what actions needed to be taken. She testified that even after a rule becomes final, the cost of compliance is uncertain. She asserted that site-specific clarity was not achieved until court approval on February 5, 2020 of the settlement dated December 31, 2019 pertaining to the Company's challenge to DEQ's April 2019 excavation order. (Id. at 234.) According to witness Williams, because of the uncertainty surrounding the regulation of coal ash, the owners and operators of coal ash impoundments acted prudently in waiting until after CAMA and the CCR Rule became law to take specific actions in upgrading or closing the impoundments as long as they were working with environmental regulators to address any site-specific environmental issues. (Id. at 235.) She then discussed seven factors that she testified "compound uncertainty in predicting the ultimate shape of EPA regulation," and further discussed regulatory uncertainty. (Id. at 238-64.)

Witness Williams also discussed damage cases identified by the EPA from CCR disposal in landfills and coal ash impoundments. She stated that EPA's 2007 Notice of Data Availability had identified 24 damage cases and 43 potential damage cases. She explained that:

> With regard to groundwater, seventeen of the damage cases were to groundwater and five or six of those were determined to be from unlined ash ponds. That is against a universe of approximately 600 ash ponds, the large majority of which were over 25 years old. And, as of 2000, EPA estimated that 62 percent of ash ponds were

> unlined. Against this number of unlined ash ponds, the number of confirmed pond damage cases to groundwater from these units was quite small.

(Id. at 262.) On cross-examination, however, witness Williams conceded that out of the "universe" of approximately 600 coal ash units, some of which were lined, and some of which were unlined, there were 135 potential damage cases on which the EPA actually gathered or received information. She further conceded that the EPA only evaluated 85 of those cases. Out of those, 24 were determined to be proven damage cases, and 43 were determined to be potential damage cases. Witness Williams, however, testified that she did not consider that to be a significant number of cases, arguing that the "proper way to analyze it is to look at how many damage cases they found and compare it to the universe, not compare it to other damage cases." (Id. at 417-25.)

Witness Williams testified regarding the 1979 Mayo study, which included data from the Roxboro facility and the 1975 Radian study. She stated that the Mayo study concluded that the soil conditions at Mayo were "adequate to provide excellent protection to the groundwater" and that "it is difficult to imagine that any significant adverse impact on the groundwater aquifer could be caused by ponding of the ash wastes at the proposed site." (Id. at 264-66.) She added that North Carolina completed screening assessments of DEP's coal ash facilities under RCRA by the mid-1980s and determined that they were considered low priority for site inspection to evaluate whether there were concerns about potentially significant environmental impacts. (Id. at 267.)

Witness Williams testified that at the Sutton facility, for which North Carolina suggested to EPA that additional groundwater investigations be performed, DEP voluntarily began detailed groundwater investigations in the early 2000s. (Id. at 265-68.) She disagreed with witness Quarles' testimony regarding the Sutton facility, stating that the "soil and groundwater conditions at Sutton were nothing like the conditions at many of the other DE Progress sites, including those in Piedmont soils." (Id. at 291.) She added that the installation of a new lined pond at Sutton was not relevant to a determination that the continued operation of existing unlined impoundments at other sites was not prudent. (Id.)

She stated that based on the Mayo study and EPA's 1988 Report to Congress, "DE Progress reasonably and prudently would have believed that its ash basins would not result in groundwater contamination at levels that would result in damage." (Id. at 266-67.) Witness Williams added that it is likely that DEP would have been aware of the 1985 Arthur D. Little Report, which concluded that no major environmental effects had occurred at any of the six sites, including DEC's Allen facility, and that groundwater wells downgradient of the coal ash disposal sites were "typically less than primary drinking water standards." (Id. at 267, fn 88.)

With regard to witness Lucas' argument that DEP should have installed comprehensive groundwater monitoring systems in the early 1980s, witness Williams argued that the knowledge wasn't available at the time. (Id. at 366-68.) She stated that there was very limited groundwater monitoring at waste management units, including coal ash impoundments, and that research was just beginning on effective and protective ways to monitor groundwater. (Id. at 266.) According to witness Williams, groundwater monitoring "was at a very early stage of sophistication." (Id. at 394-95.) She stated that "it's not clear, in that early time frame, that punching tons of additional wells would have provided the kind of information that you're hoping that Duke could have gotten from that." (Id. at 402.) Likewise, she testified that "there wasn't a tremendous effort to get people to go punch holes in the ground everywhere to get information that at the time was still not entirely helpful to regulatory decision-making." (Id. at 401-02.)

Witness Williams contended that the intervenors appeared to downplay or overlook the role of regulations and permits, and that the fact that neither the use of liners nor the installation of groundwater monitoring systems was mandated by state or federal regulations is an important factor in assessing the reasonableness of DEP's historic activities. In addition, witness Williams testified that the intervenors failed to assess the state of industry practices at the time. (Id. at 275.) She asserted that "[i]n my almost 50 years of environmental experience, even in the absence of regulations, it is very unusual to see large parts of an industry continue to handle waste in a manner likely to lead to environmental harm once knowledge of that environmental harm is generally confirmed." (Id. at 276.)

Witness Williams testified that DEQ had regulatory authority over DEP's coal ash impoundments for decades. She argued that the fact that DEQ did not require liners, closure of the impoundments, or groundwater monitoring earlier than it did was a strong indication that the Company's operations were considered to be reasonable and protective by DEQ. (Id. at 276-77.) She also argued that if

EPA's information had demonstrated a risk that was generally not being addressed by the states, EPA would have moved forward with a recommendation for national minimum standards requiring liners and groundwater monitoring well before it promulgated the final CCR Rule in 2015. (Id. at 280.) She further testified that in evaluating whether a company operated reasonably, it is appropriate to compare it to others in the same or similar industries, citing the 1988 EPA Report to show that the majority of coal ash surface impoundments in the United States were unlined at the time, and that the EPA stated in its 2010 proposed CCR Rule that 62 percent of surface impoundments at that time were unlined. She also cited to 1988 Report to show that 65% of surface impoundments at the time did not have groundwater monitoring. Witness Williams stated that state agencies such as DEQ were in the best position to determine situations in which existing impoundments needed to upgrade to liners or install groundwater monitoring systems. (Id. at 282-83.)

Witness Williams testified that an assessment of whether a particular coal ash impoundment was likely to contaminate groundwater at levels understood at the time to equate to environmental harm was "necessarily site-specific as a host of factors including the permeability of soils, the vertical distance between the waste and the aquifer, the amount and type of waste being managed, the depth and direction of groundwater can all affect the potential of an ash pond to leach to groundwater." (Id. at 297-98.)

Witness Williams testified that beginning around 1980, the EPA began collecting information on instances of environmental damage from industrial waste management, including groundwater contamination. (Id. at 306.) She stated that in its 1988 Report to Congress, the EPA detailed a "relatively small number of damage cases and even a smaller number of damage cases that involve contamination of groundwater from coal ash ponds." (Id. at 306-07.) She added that where the damage cases involved the exceedance of a drinking water standard, the EPA noted that "the total number of exceedances is quite small compared to the total number of monitoring wells and samples gathered." (Id. at 307, quoting the 1988 EPA Report to Congress at 5-67.) She also testified that the EPA concluded in its report that the "actual potential for exposure to human and ecological populations was likely to be limited because ground water in the vicinity of utility waste disposal sites is not typically used for drinking water and the contaminants tend to be diluted in nearby surface water bodies." (Id. at 307.) She concluded that this led to the EPA's conclusion that "current waste management practices appear to be adequate for protecting human health and the environment," and its decision in 1993 not to regulate CCR as a hazardous waste. (Id. at 307, quoting the 1988 EPA Report to Congress at 7-11.)

Witness Williams next addressed witness Hart's estimation of the costs DEP would have incurred if it had taken earlier action with respect to its coal ash impoundments, and discussed why she believed his estimation of costs "relies on faulty assumptions and is entirely speculative." With regard to witness Hart's contention that actions on an accelerated schedule almost always cost more, she stated that he offered no evidence to support his contention and that it was her experience that "tighter timeframes for projects sometimes lead to efficiencies, including expedited regulatory review times, that reduce project costs." (Id. at 318-26.)

Witness Williams discussed the 2L rule, describing it as a remedial requirement and explaining that while compliance laws and regulations "seek to prevent . . . activities from resulting in harm to the environment," remedial laws and regulations "seek to address environmental harm that is resulting from past or ongoing activities." (Id. at 328-29.) She stated that punishing or penalizing a party for an exceedance under the 2L rules "would be very problematic." (Id. at 333.) Instead, she argued that such exceedances are used to trigger the investigation and potential remediation required under the rule. She testified that the number of DEP's exceedances, as discussed by witness Lucas in his testimony, is "entirely dependent on how frequently the Company conducted groundwater sampling," and that the number of exceedances would be significantly higher if the company sampled daily than if it sampled weekly. She stated that treating exceedances as violations with associated penalties would create a disincentive for parties to sample frequently or comprehensively. (Id. at 333-34.)

During the hearing, witness Williams disagreed that once the 2L rule was adopted in 1979 and groundwater standards were in place, the Company had a responsibility to assess whether or not it was meeting those groundwater standards and to take action based upon that knowledge. She testified that it was a joint responsibility, and that, "in fact, it was a responsibility of the regulatory agency." She added that if the regulatory agency believed the design and operational requirements of existing facilities were inadequate to meet the groundwater standards, the permits should have included additional requirements. Witness Williams stated that in her experience, if groundwater monitoring was an expected requirement, it would be written into the regulations or individual permits. (Id. at 347-49.)

Witness Williams was also asked whether it was her position that the absence of regulatory action on the part of DEQ is an endorsement of the Company's practices. She testified that she believed it was an indication of what the knowledge base was at the time, and that the knowledge at that time was not sufficient to say that the Company's coal ash basins were going to result in contamination of groundwater above the state groundwater standards or health protective levels. She added that the states, Congress, and EPA had higher priorities, including identifying and addressing hazardous waste facilities and open dumps. (Id. at 351-53.) Witness Williams conceded that whether or not coal ash impoundments were a priority with DEQ, the Company still had to comply with regulations and permits that were specific to their facilities. She stated that "clearly, if they violated those standards, . . . working with the regulator, they would have had to address what needed to be done . . . ." (Id. at 354.) She added, however, that "addressing an exceedance is different than saying they were required to monitor the groundwater." (Id.)

During the hearing, witness Williams conceded that waste does not have to be a hazardous waste in order to have a potential impact on groundwater. (Id. at 370.) She also confirmed that her testimony indicated that the impacts of coal ash disposal are site-specific. She testified that Piedmont soils "fit within a certain class of materials," and that many of the factors relevant to the impacts of coal ash disposal are similar between "facilities that were all located in similar geology." (Id. at 372-73.)

Witness Williams was also asked about her testimony that "in the absence of site-specific information to the contrary, it is my opinion that it would be reasonable and prudent in this pre-2000 period for an owner of an existing ash pond without liners or without an ongoing groundwater monitoring system to continue to operate the ash ponds." Specifically, she was asked how the Company would have discovered site-specific environmental issues such as groundwater contamination without monitoring at each site. Witness Williams testified that you may see impacts on fish health in surface water, vegetation impacts, or a nearby or on-site drinking water well with taste and odor problems. She added that if there was a pattern of what was being identified, that the regulatory agency would typically then require that groundwater monitoring wells be installed. (Id. at 399-401.)

DISCUSSION AND CONCLUSIONS

Historical Knowledge

First, the Commission acknowledges the Company's assertion that unlined coal ash impoundments were an accepted approach when DEP constructed its impoundments. The Commission agrees, and accepts that the Company's approach to coal ash basin construction was reasonable and consistent with that of other electric utilities in the 1950s, 1960s, and perhaps even the 1970s. This fact, however, does not address the question of whether DEP knew or should have known, by the early 1980s, that unlined coal ash impoundments had the potential to contaminate groundwater and surface water. Likewise, while both witnesses Wells and Williams assert that DEQ and the EPA allowed the continued use of unlined ash basins until promulgation of CAMA and the CCR Rule, this assertion does not bear on whether or not the Company knew or should have known that unlined impoundments had the potential to contaminate the surrounding environment. Nevertheless, the usage and prospects of unlined impoundments declined with the promulgation of environmental laws and regulations in the 1970s, such as the Clean Water Act in 1972, the Steam Electric Power Generating Effluent Guidelines and Standards in 1974, the Resource Conservation and Recovery Act in 1976, and the 2L Rules in 1979.

The Commission is persuaded that the historical documents cited by the intervening parties, many of which were industry publications, academic publications, and governmental reports, represent an awareness that began to accumulate as early as the late 1970s that unlined coal ash impoundments had the potential to contaminate groundwater and surface water. It is evident that by the early 1980s, this awareness was not merely speculation or on the fringes of academia or industry. Rather, the knowledge regarding the potential risks associated with coal ash disposal had grown to such an extent that EPRI, an electric utility industry group, published two manuals with guidance for assessing, addressing, and preventing such risks—the 1981 EPRI Manual and the 1982 EPRI Manual. The Commission disagrees with the assertion of witness Wells that intervenors "cherry-picked" statements from historical documents. The Commission agrees with witness Quarles that context is important when reviewing such documents, and is of the opinion that important information can be found throughout a report, manual, or study.

Witness Williams argued that the EPRI manuals were not representative of industry knowledge at the time, and that they were "just trying to share the information as to what could potentially be happening." The Commission does not find this argument persuasive, as the publication of a manual by an industry group would necessarily represent the information the Company had available to it at the time. Furthermore, the other documents cited by the intervening parties likewise showed the potential for contamination from unlined impoundments—the EPRI manuals were not the lone sources of such knowledge at the time. The Commission also notes that "shar[ing] the information as to what could potentially be happening" with respect to coal ash disposal appears to be precisely what the intervenors contend the EPRI manuals were intended to do.

Witness Williams testified that, in her opinion, the intervenors selectively referred to various documents without weighing the broader set of available knowledge at the time. She did not, however, provide any documents or publications from the late 1970s or early 1980s that contradicted the idea that unlined coal ash impoundments had the *potential* to contaminate groundwater and surface water. Witness Wells conceded in his testimony that the Company "certainly" was aware that its impoundments had the potential to impact the environment, but that he did not believe that the general knowledge of potential for impacts resolved the question of whether the Company's impoundments actually posed a significant risk to human health or the environment. Likewise, witness Williams argued that "asserting that DE Progress knew ash ponds generally had the 'reasonable potential' . . . to contaminate groundwater, even if true, does not tell you anything about what DE Progress did or did not know about the likelihood for any particular ash pond it operated to contaminate groundwater at levels that were understood, at the time, to equate to environmental harm." The question of what the Company knew about actual contamination at its impoundments is discussed in the Equitable Sharing section below.

Based on the foregoing and the entire record, the Commission finds and concludes that the Company knew or should have known by the early 1980s that the wet storage of CCR in unlined impoundments had the potential to contaminate surrounding groundwater and surface water.

Equitable Sharing

The Commission also concludes that, contrary to the testimony of DEP witness Bednarcik, the Company's operation of its coal ash impoundments prior to the CCR Rule and CAMA was not "always in compliance with" existing law.

It is clear that North Carolina through its 2L rules prohibited exceedances of the groundwater standards beginning in 1979, and while the rules were indeed revised to include remedial measures, they are not solely remedial, as contended by DEP witness Williams. A straightforward reading of the rules, as presented in Hart Exhibits 8 and 10, shows that the 2L rules both prohibit exceedances and provide requirements for corrective action. Furthermore, the testimony and evidence provided by witnesses Lucas, Hart, and Quarles demonstrate that DEP was aware of exceedances at its Sutton facility in the mid-1980s, and at other sites as it implemented groundwater monitoring in the late-1980s, 1990s, and 2000s, yet failed to initiate comprehensive groundwater monitoring at any of its coal ash sites until many years later. As provided in witness Lucas' testimony and Lucas Exhibits 11 and 12, the Company has accumulated a total of 7,411 exceedances at its North Carolina sites and a total of 632 exceedances at its Robinson site in South Carolina. The Commission is persuaded that these exceedances represent mounting evidence of the extent of the contamination caused by DEP's coal ash impoundments. As explained by witness Lucas, these exceedances do not represent sampling of the same water over and over—rather, the Company is detecting different contaminants as the groundwater flows, and is defining the extent and severity of the contamination plumes at each site. Furthermore, although Company witness Wells frequently emphasizes the exceedances of naturally occurring substances such as pH, iron, and manganese in his testimony, it is apparent in the record that background levels have been exceeded and that many other constituents account for the Company's exceedances as well, including arsenic, chromium, cobalt, lead, and vanadium.[5] The Company has also identified exceedances during its detection and assessment monitoring pursuant to the federal CCR Rule. Furthermore, the extent and severity of groundwater contamination is confirmed by the robust groundwater remediation approach,

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[5] Lucas Exhibit 11.

including extraction and treatment and clean water infiltration, proposed to DEQ in the Company's updated Corrective Action Plans.[6]

With respect to the 2L rules, the Commission agrees with witness Lucas that an exceedance of the 2L standards at or beyond the compliance boundary and above background levels constitutes a violation of the 2L rules. The Commission notes that this is also DEQ's interpretation of the rules, as provided in DEQ's recent amicus brief before the North Carolina Supreme court.[7] As the state agency tasked with regulatory oversight over the 2L rules, DEQ's interpretation of the regulations should be given great weight.

Likewise of concern to the Commission, witness Wells testified that DEP has taken every action required by DEQ to address groundwater impacts. In fact, DEP litigated for years against the DEQ efforts to obtain corrective action through its state court enforcement action brought in 2013. Moreover, the 2L regulations require first and foremost that groundwater exceedances be prevented, whereas witness Wells touted the virtue of the Company's efforts to clean up its violations. The Commission finds that the large extent of groundwater violations is not a model of compliance as the Company witnesses claim; rather, it shows a widespread failure to comply.

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[6] For example, the December 31, 2019 Corrective Action Plan Update for the Roxboro facility describes the following groundwater remediation measures: 5 extraction wells in the area of the unnamed pond north of the East Ash Basin (EAB) compliance boundary; 15 extraction wells on the northeast side of the EAB compliance boundary; 12 extraction wells near the north of the EAB compliance boundary adjacent to the Dry Fly Ash silos, transport, and handling area; and 18 extraction wells and 27 clean water infiltration wells adjacent to the Intake Canal. December 31, 2019 Corrective Action Plan Update for the Roxboro Steam Electric Plant at ES-4.

[7] Lucas Exhibit 10.

The record is also clear that the Company was not in compliance with its NPDES permits, as evidenced by unauthorized discharges, or seeps, from its coal ash impoundments, in violation of N.C.G.S. § 143-215.1. There is substantial evidence in the record of both deliberately constructed seeps and non-engineered seeps at DEP's facilities. Such evidence includes the lawsuits filed by DEQ in 2013 for unlawful discharges at DEP's impoundments,[8] the Joint Factual Statement in the federal criminal case against DEP and DEC,[9] the SOCs entered into between DEP and DEQ for the seeps at the Asheville, Cape Fear, H.F. Lee, Mayo, Roxboro, and Weatherspoon plants,[10] and the independent audits conducted at each facility.[11] The enforcement actions filed by DEQ in 2013 gave clear warning to DEP that it must correct its illegal seeps, yet most of its coal ash sites were still out of compliance five years later, as shown by the Final Audit Reports.

The Commission next considers whether the Company is "culpable" for the violations of environmental laws and regulations discussed above. The Commission understands the term "culpable" in this context to mean that the Company had a responsibility or duty to comply with environmental laws and regulations, and failed to do so. As established earlier in this Order, the Company knew or should have known of the risks of unlined surface impoundments by the

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[8] On August 16, 2013, DEQ filed a lawsuit against DEP in the Wake County Superior Court for environmental violations at Cape Fear, H.F. Lee, Mayo, Roxboro, Sutton, and Weatherspoon. Likewise, on March 22, 2013, DEQ filed a lawsuit against DEP in Wake County Superior Court for environmental violations at the Asheville facility. See Lucas Exhibit 8, Docket No. E-2, Sub 1142.

[9] Hart Exhibit 3.

[10] Lucas Exhibits 7-9.

[11] Lucas Exhibit 14.

early 1980s. The Commission is persuaded that despite its knowledge of this potential risk, the Company failed to practice adequate risk management. The Company argues that knowledge of the potential risk of contamination did not equate to knowledge of any actual risk at its facilities, but that is precisely the point. A responsible utility would have assessed the risk of contamination at its facilities. As discussed in the testimonies of witnesses Lucas, Hart, and Quarles, industry manuals in 1981 and 1982 specifically noted the importance of conducting groundwater monitoring at coal ash impoundments. The Commission notes that this is true of the 1981 EPRI manual even though it was aimed at new facilities, as that particular guidance was logically applicable to all impoundments, not just new impoundments.

The Company points to the testing conducted at Roxboro in 1978 and Mayo in 1979, as well as the Company's awareness of the 1985 Arthur D. Little study, to argue that the Company properly concluded that DEP's coal ash impoundments would have no significant impact on groundwater or surface water. The Commission notes that Company witnesses Wells and Williams stated numerous times in their testimony that assessing the impacts of coal ash impoundments on groundwater and surface water is a site-specific determination, with factors such as soil permeability, the vertical distance between the waste and the aquifer, and the depth and direction of groundwater potentially affecting the potential for coal ash to leach into groundwater. Yet, the Company argues that groundwater monitoring conducted at the Roxboro and Mayo facilities was sufficient to make a conclusion about the impacts of its impoundments at each of its facilities. The

Commission is in accord with witness Lucas' testimony that such evaluations are necessarily site-specific, and that the Company should have conducted an assessment at each site.

Importantly, the Commission notes that the Company chose to use as its representative facilities (1) Roxboro, which had impoundments that had only been in operation for 12 years and five years, respectively, and (2) Mayo, at which a coal ash impoundment was not yet constructed or in operation. Likewise, the testing at DEC's Allen facility that would form the basis for conclusions in the 1985 Arthur D. Little study was conducted from 1979-1982, while the impoundment at Allen had only begun operation in 1972.[12]

Intervenors pointed to a number of deficiencies with respect to the Company's reliance on the Roxboro and Mayo studies and the 1985 Arthur D. Little report, as detailed herein and in the record. For example, witness Quarles testified that the testing showed that arsenic concentrations in groundwater beneath the Allen site exceeded drinking water standards, but that the report's conclusions appeared to look only at impacts to the adjacent surface waterbody and not to groundwater quality. He also testified that the report concluded that increasing concentrations of constituent concentrations downgradient of the coal ash impoundments "would be expected."

Because of the numerous deficiencies identified by intervenors with respect to the Company's reliance on these studies, and the importance of site-specific

[12] Lucas Exhibit 4.

evaluations as acknowledged by the Company, the Commission concludes that it was not reasonable for DEP to rely on the Roxboro, Mayo, and Arthur D. Little studies to support a conclusion that there would be no significant impact to groundwater or surface water from coal ash impoundments at any of its eight facilities.

The Commission also notes that despite Company witness Williams' testimony that the knowledge and development of groundwater monitoring techniques were inadequate in the early 1980s, the Company continued to rely for decades on the results of its testing at Roxboro in 1978 and Mayo in 1979 (before the coal ash impoundment at Mayo was constructed), as well as testing conducted at DEC's Allen site between 1979 and 1982, which provided the data used in the 1985 Arthur D. Little study. In sum, the Commission is persuaded by the testimony of the parties and the entire record that the Company was not reasonable in relying on the Roxboro and Mayo studies or the 1985 Arthur D. Little study for its decision to not conduct groundwater monitoring at each of its facilities.

Further, with respect to witness Williams' testimony regarding the state of knowledge of groundwater monitoring in the early 1980s, the Commission is of the opinion that a responsible utility would have conducted groundwater monitoring as best as it was able with the knowledge it had available to it at the time, including working with Arthur D. Little, EPRI, and regulators. The Commission notes that the Company, however, seemed to historically over-rely on testing conducted at only one site, only to argue now that groundwater monitoring techniques were not understood or developed enough to justify even attempting to test at its other sites.

The record shows that although the Company continued to collect evidence of exceedances at its coal ash impoundments in the late 1980s and throughout the 1990s, it did not begin comprehensively monitoring the groundwater at its facilities until the mid to late 2000s.[13] The Commission further notes that, as presented in the testimony and exhibits of intervenors and as discussed later in this Order, the Company had not fully established reliable background levels at all of its plants until the 2010s. The Commission is of the opinion that the failure of the Company to conduct monitoring at each facility at a much earlier date, given the knowledge it had of potential impacts in the early 1980s, was unreasonable.

It is also evident, as testified to by intervenor witnesses and confirmed by witness Wells during the hearing, that the nature of the waste stream changed over time as the Company installed air pollution control devices, thereby diverting new and different types of waste into the coal ash impoundments. Although these new waste streams contributed to constituent loading and had the potential to change the pH within the impoundments, thereby mobilizing metals, the Company continued to operate its coal ash impoundments in the same manner as it had before.

The Company raised several defenses with respect to its inaction, particularly in the 1980s. First, it argued that its coal ash management practices were consistent with industry practice at the time. Industry practice, however, does not relieve DEP of its responsibility to practice adequate risk management at its

[13] Lucas Exhibit 18.

coal ash impoundments. The record clearly shows that there was some understanding of groundwater risk well before industry standards changed. Furthermore, the salient fact is that once 2L regulations were adopted in 1979, the Company had a legal duty to prevent groundwater contamination, and also a duty after 1984 to take corrective action where contamination did occur. Following standard industry practice did not relieve DEP of its legal duty to comply with North Carolina's 2L groundwater standards or act responsibly with respect to its ash basins, and as a prominent utility in the Southeast, the Company would have been among those setting the industry standard.

The Company implied that its historical inaction with respect to its coal ash management practices is partially attributable to other parties. For example, Company witness Wells stated that "intervenors downplay that DE Progress' environmental regulators, utility regulators, and intervenors themselves were participants in the Company's long history of coal-fired generation in the Carolinas." The Company asserted that DEQ only began adding monitoring requirements to the Company's NPDES permits in 1990, and that DEQ did not require groundwater monitoring in all the Company's NPDES permits until 2010. The Commission is persuaded, however, that inaction on the part of a regulator does not relieve DEP of its duty to comply with the 2L regulations and practice adequate risk management. DEP witness Wells admitted during cross-examination that the Company is ultimately responsible for its management of coal ash and compliance with environmental regulations, and the Commission concludes that the Company had the responsibility to assess the risk of contamination at its coal ash sites, rather than wait for a directive to do so by DEQ.

Likewise, Company witness Wells referred to the Commission's authority over dam safety inspection reports between 1967 and 2009 to argue that DEQ and the Commission were aware of seeps from the Company's basins well before the CCR Rule and CAMA. During cross-examination, however, he conceded that the reports were intended to assess dam safety and integrity, and that they were not intended to be water quality inspections. Again, the Commission emphasizes that the Company alone was ultimately responsible for compliance with environmental regulations and for the management of its coal ash impoundments.

Witness Williams also contended that the Company acted prudently in waiting until after CAMA and the CCR Rule became law to take specific actions in upgrading or closing the impoundments as long as they were working with environmental regulators to address any site-specific environmental issues. The Commission, however, emphasizes that the Company has had a duty to comply with the 2L rules since 1979—that requirement, indeed, had been quite certain for more than three decades before CAMA and the CCR Rule were enacted and promulgated, respectively. While CAMA and the CCR Rule did undoubtedly provide the Company with certainty regarding methods of closure and corrective action, the Commission is of the opinion that regulatory requirements are ever changing, and that waiting decades to take action with respect to the Company's coal ash impoundments even though the Company was already obligated to comply with the 2L rule and was aware of potential and actual contamination at its coal ash sites was unreasonable.

The Company also accused intervenors of using “hindsight bias” to unfairly judge and criticize the Company’s historical coal ash management practices. Upon a review of the entire record, however, the Commission is of the opinion that the Company failed to provide any specific examples of the intervenors’ reliance on hindsight. Rather, it appears that intervenors were careful to only apply the knowledge that was available at the time to their assessments of the Company’s actions and inactions. In the absence of evidence to the contrary, the Commission concludes that the intervenors’ assessment of the Company’s historical coal ash management practices was appropriate and did not rely on hindsight.

The Company’s position that its coal ash costs were necessary to comply with the CCR Rule and CAMA misses an essential point. The Company’s extensive environmental violations, occurring at all its former and current coal-fired power plants across the Carolinas, would have required remediation at considerable expense even without the CCR Rule and CAMA. The CCR Rule and CAMA were simply responses to the extensive environmental damage caused by the storage of coal ash in impoundments, including structural collapses and groundwater contamination. It would be inequitable and poor public policy to conclude that enactment of the CCR Rule and CAMA should shield DEP from cost responsibility for its violations. Certainly, there is no indication that the EPA or the General Assembly intended to shield the Company from this cost responsibility.

With regard to the question of culpability, and as discussed herein, the Commission concludes that the Company had a duty to comply with the state's 2L rules and its NPDES permits pursuant to N.C.G.S. § 143-215.1, and that it failed that duty. Furthermore, the Commission concludes that the Company's historical inactions—namely, its failure to conduct groundwater monitoring at each of its facilities and take appropriate action based on the results obtained—render the Company culpable for its extensive environmental violations. These environmental violations have directly and indirectly led to significant costs for remediation and closure, for which the Company is requesting recovery from ratepayers.

With respect to the Public Staff's equitable sharing argument, the Commission finds and concludes that it is fair and reasonable to share coal ash-related costs between shareholders and ratepayers. The Commission agrees with the Public Staff that a traditional prudence review is precluded in the case of the Company's coal ash costs due to the virtual impossibility of conducting a comprehensive review of Company records over the 1970s to early 2000s timeframe, the difficulty in determining alternative actions, and the difficulty in quantifying historical costs. Aside from the specific prudence disallowances recommended by the Public Staff, the Commission concludes that it is appropriate to apply equitable sharing to the remaining coal ash costs incurred by the Company from September 1, 2017 through February 29, 2020.

The Commission further agrees with the Public Staff's position that culpability is a relevant factor that the Commission has the discretion to consider in setting rates, pursuant to N.C.G.S. § 62-133(d). Culpability is fact and case-specific, and, in the present case, is due to the Company's failure to comply with longstanding legal and regulatory requirements, resulting in costly remediation and closure requirements. As explained by witnesses Lucas and Maness, the Public Staff's equitable sharing recommendation is based in part on the Company's culpability for its failure to comply with environmental laws and regulations for the protection of groundwater and surface water, and in part on the magnitude and nature of the costs. Witness Maness explained that equitable sharing is reasonable and appropriate in light of the Commission's history of cost sharing between shareholders and ratepayers for certain unusual costs of large magnitude, including the costs of abandoned nuclear construction and manufactured gas plant remediation. As such, he testified that some percentage of equitable sharing would be appropriate even in the absence of culpability.

The Company's challenge to the Public Staff was framed in terms of a prudence analysis, which is different from the Public Staff's equitable sharing position. Imprudent acts or omissions would give rise to a 100% disallowance of specific costs under N.C.G.S. 62-133(b). The equitable sharing of coal ash costs is instead based on DEP's failure to comply with environmental laws and regulations, which shows Company culpability without regard to imprudence. It is also based on the magnitude and extraordinary nature of the costs, which are factors underlying previous equitable sharing decisions of the Commission. For equitable sharing, as opposed to prudence, the applicable statute is N.C.G.S. 62-133(d).

The role of the Commission in general rate case proceedings is to set rates that are fair and reasonable for the utility and its customers, within the parameters set forth in the North Carolina General Statutes. These parameters include the provisions of N.C.G.S. § 62-133(a), which provides that "the Commission shall fix such rates as shall be fair both to the public utilities and the consumer," and also N.C.G.S. § 62-133(d), which provides "[t]he Commission shall consider all other material facts of record that will enable it to determine what are just and reasonable rates." These statutory provisions are in addition to the ratemaking formula in N.C.G.S. § 62-133(b). A total disallowance of certain costs under N.C.G.S. § 62-133(b), on the grounds that those costs are unreasonable, is subject to the prudence standard. The prudence standard examines whether the utility's actions and decisions were reasonable based on what it knew or should have known at the time of decisions, actions, or omissions that led to the costs in question.

In contrast, the exercise of Commission discretion under N.C.G.S. § 62-133(d), including a decision for equitable sharing, is lawful where "other material facts of record" justify an adjustment necessary to achieve "reasonable and just rates." Unlike the cost-oriented prudence standard under N.C.G.S. § 62-133(b), a rate-oriented equitable sharing decision under N.C.G.S. § 62-133(d) does not require the identification of particular or specific costs as resulting from an imprudent decision or act of the utility. N.C.G.S. § 62-133(d) allows for an equitable sharing when otherwise prudent costs would be unreasonable or unjust to include in rates. Because the equitable sharing option alters the normal practice of allowing prudent and reasonable costs into rates, it should be applied only in unusual circumstances where material facts of record support equitable sharing as the way to achieve reasonable and just rates. For purposes of this proceeding, the Commission finds that “other material facts of record” justify an equitable sharing of CCR expenditures.

Based on the foregoing and the entire record, the Commission finds and concludes that equitable sharing of the coal ash remediation costs, net of disallowances, between ratepayers and investors is fair and reasonable pursuant to N.C.G.S. § 62-133(d), which provides that “[t]he Commission shall consider all other material facts of record that will enable it to determine what are reasonable and just rates.” The Commission agrees that culpability is a relevant factor in determining what are “reasonable and just rates” for the recovery of CCR-related costs, and concludes that it would be unjust to require ratepayers to bear the entirety of the deferred coal ash costs where those costs include corrective actions to remedy the Company’s environmental violations. The Commission also finds and concludes that, even in the absence of culpability, some level of sharing would be appropriate and reasonable in this proceeding due to the magnitude and extraordinary nature of the coal ash closure and remediation costs.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7-8

The evidence supporting these findings of fact and conclusions is contained in the Application, Form E-1, and the testimony and exhibits of DEP witnesses Jessica L. Bednarcik and James Wells, Public Staff witnesses Jay B. Lucas, Michelle M. Boswell, and Michael C. Maness, and AGO witness Steven C. Hart.

Summary of the Evidence

DEC DIRECT TESTIMONY

In her direct testimony, DEP witness Bednarcik testified that DEP is seeking recovery of CCR expenses incurred from September 1, 2017 through June 30, 2019, and costs to be incurred through February 29, 2020, related to reasonable, prudent, and cost-effective approaches to comply with applicable regulatory requirements. (Tr. vol. 12, 33.) Witness Bednarcik testified that pursuant to CAMA, the impoundments at Asheville and Sutton were designated as "high priority" sites with closure by excavation required at Sutton by August 1, 2019, and at Asheville by August 1, 2022. (Id. at 37.)

Witness Bednarcik provided site details and a description of the work performed at the Asheville site in Bednarcik Exhibit 7. Likewise, she provided site details and a description of the work performed at the Sutton site in Bednarcik Exhibit 10. Both exhibits state, in part, that "[t]he tasks that DE Progress has performed and will perform from September 1, 2017 through February 29, 2020 are a continuation of the activities for which costs were approved in the prior DE Progress rate case" and that "[t]hese activities and associated costs continue to be necessary, appropriate, and consistent with applicable regulatory requirements." (Bednarcik Exhibits 7 and 10.)

Witness Bednarcik concluded that the closure activities described in her testimony for each site were necessary to comply with regulatory obligations, that processes are utilized to ensure costs "are not exorbitant, unnecessary, wasteful, or extravagant," and that the Company has properly managed the activities to ensure compliance with schedules and deadlines. (Id. at 56-58.)

INTERVENOR TESTIMONY

Public Staff witness Lucas recommended the disallowance of costs incurred at the Asheville and Sutton plants for groundwater extraction and treatment and for the purchase of land at the Mayo plant. He testified that costs to remedy environmental violations where the costs exceeded what CAMA would have required in the absence of violations should be disallowed from recovery in rates, which is consistent with the Public Staff's position in the Sub 1142 rate case and the pending appeal before the North Carolina Supreme Court. DEP installed and operated wells and appurtenances for the extraction and treatment of groundwater at the Asheville and Sutton plants, and purchased land at the Mayo plant to mitigate the risk of spreading groundwater contamination. The total costs incurred amounted to $1,240,328. Witness Lucas testified that groundwater extraction and treatment would not be required by CAMA or prior regulations, nor would it be necessary, if DEP had not caused violations of the state's groundwater quality standards. (Tr. vol. 15, errata 6-7.)

In his testimony in the present rate case, Public Staff witness Lucas incorporated by reference his testimony from the Sub 1142 rate case regarding the groundwater quality at the Asheville, H.F. Lee, Mayo, and Sutton plants, groundwater extraction and treatment performed by DEP, and associated costs. In the Sub 1142 rate case, witness Lucas testified that DEQ had assessed a $25.1 million penalty for violations of 2L groundwater standards at the Sutton plant, and that DEP had contested the findings of the assessment in a petition filed at the Office of Administrative Hearings. On September 29, 2015, DEP's petition for a contested case was dismissed pursuant to a settlement agreement between Duke Energy and DEQ. In the settlement agreement, Duke Energy admitted no wrongdoing, but agreed to pay a $7 million penalty to DEQ and to accelerate the remediation of coal ash at DEP's Sutton, Asheville, and H.F. Lee plants and DEC's Belews Creek plant. The remediation work for Sutton included extraction wells to pump groundwater in an effort to slow offsite migration from the ash basins. (Docket No. E-2, Sub 1142, Tr. vol. 18, 262-64.)

Witness Lucas summarized that DEP contaminated the groundwater at the Asheville, H.F. Lee, Mayo, and Sutton plants in violation of the 2L rules. The settlement signed by the Company states in part: "data show constituents associated with the ash basins at concentrations over the 2L standards . . . have migrated off site," and "[e]xtraction wells will be used to pump the groundwater to arrest the offsite extent of the migration." He also stated that DEP has purchased land near the Asheville and H.F. Lee plants to "mitigate the risk of groundwater contamination from reaching off-site property owners." (Tr. vol. 15, errata 63-64.)

Witness Lucas explained that in the present rate case, the Company is seeking recovery of costs incurred at Asheville and Sutton for groundwater extraction and treatment, and for the land purchase at Mayo. He added that the costs for groundwater extraction and treatment at H.F. Lee and the land purchases at Asheville and H.F. Lee are not included in the present rate case. (Id. at errata 64.)

Witness Lucas testified that DEP is extracting and treating groundwater at the Asheville and Sutton plants because it is responsible for contaminating the groundwater with coal ash constituents such as arsenic, boron, chromium, manganese, selenium, and others. He stated that the Public Staff's position is that DEP should not place these costs on ratepayers. Witness Lucas also testified that DEP witness James Wells admitted during the Sub 1142 rate case that DEP would not have had to install extraction wells if there had been no exceedances. (Id. at errata 65.)

Witness Lucas noted that in its Sub 1142 Order, the Commission stated that "there is insufficient evidence that the Company would have had to have engaged in any groundwater extraction and treatment activities absent the obligations imposed upon it by CAMA and/or the CCR Rule." Witness Lucas asked that the Commission take a fresh look at the treatment of groundwater extraction and treatment costs in this case. (Id. at errata 66.)

Witness Lucas stated that DEP has a cumulative total of 1,685 groundwater violations at the Asheville plant, 1,402 groundwater violations at the H.F. Lee plant, 328 groundwater violations at the Mayo plant, and 1,778 groundwater violations at the Sutton plant.[14] He testified that from a factual standpoint, there was no reason for DEP to extract and treat groundwater unless the Company was responsible for the contamination, and that the exceedance reports show that the groundwater was contaminated by DEP's coal ash impoundments. From a legal standpoint, witness Lucas testified that counsel advised him that it is an error to conclude that

[14] Lucas Exhibit 11.

CAMA or the CCR Rule would have required extraction and treatment of the groundwater at Asheville and Sutton if there were no violations of groundwater quality standards. (Id. at errata 66-67.)

Witness Lucas recommended that the expenditures for groundwater extraction and treatment at the Asheville and Sutton plants not be included in DEP's pro forma adjustment set forth in the E-1, Item 10, NC-1103. He recommended that these costs be disallowed because they are due solely to environmental violations and they exceed the amount of costs required for CAMA compliance in the absence of environmental violations. He also recommended that the costs for the land purchase at the Mayo plant to mitigate the risk of spreading groundwater contamination be disallowed. Witness Lucas testified that these costs should be disallowed because they are due solely to environmental violations and they exceed the amount of costs required for CAMA compliance in the absence of environmental violations. (Id. at errata 67-68.)

AGO witness Hart testified that exceedances of the 2L standard for boron, selenium, and manganese were detected downgradient in a groundwater monitoring well in bedrock at the Asheville site in 2006, and that in addition to those compounds, exceedances of sulfate and total dissolved solids were detected within the compliance boundary in 2007. Manganese was detected above the 2L standard at the compliance boundary in 2007. He noted that in 2010, groundwater monitoring began at and outside of the compliance boundary, and exceedances above the 2L standards and Interim Maximum Allowable Concentrations (IMACs) and above background levels were detected for boron, total dissolved solids, manganese, iron, sulfate, and thallium. He added that exceedances of cobalt were detected in 2015 when the analyte list was expanded, and that there were significant increases in boron concentrations downgradient of the 1964 impoundment in the 2016 timeframe. (Tr. vol. 13, 627-28.)

With respect to the Mayo plant, AGO witness Hart testified that groundwater monitoring that was initiated in 2008 detected exceedances of manganese and iron above the 2L standards in downgradient wells, but that there were anomalously high concentrations in the background well in early monitoring that were not confirmed in later sampling. In 2010, additional monitoring wells along the compliance boundary cross-gradient and downgradient of the ash basin detected exceedances of the 2L standard or IMAC and background concentrations for boron, manganese, and total dissolved solids. He stated that concentrations of boron in downgradient wells increased over time until they were above the 2L standards in the 2014 to 2015 timeframe. (Id. at 651-52.)

With respect to the Sutton plant, AGO witness Hart testified that groundwater monitoring indicated impacts of Total Dissolved Solids and chlorides both inside and outside the compliance boundary in the mid-1980s. By 1990, exceedances of the 2L standard for iron were detected outside the compliance boundary and along the property boundary. In 2006, concentrations of arsenic, boron, iron, and manganese were detected above 2L standards around the former ash disposal area, also known as the lay of land area. In 2011, groundwater monitoring began at and outside the compliance boundary and detected exceedances above the 2L standards, IMACs, and background levels for iron, manganese, thallium, total dissolved solids, and boron. He added that exceedances of cobalt and vanadium were detected in 2015 when the analyte list was expanded. (Id. at 671-73.)

DEP REBUTTAL TESTIMONY

In her rebuttal testimony, DEP witness Bednarcik testified that the Company has incurred $1,240,328 related to its extraction well system at the Asheville and Sutton facilities and its "land purchase to mitigate groundwater risks at Mayo." (Tr. vol. 17, 130.) stated that the Public Staff recommended disallowance of rate recovery for the cost of extraction wells and groundwater treatment in the 2017 rate case, and that the Commission "rightly rejected the proposed disallowance, finding that the Company's CCR expenses, including those related to the Asheville and Sutton extraction wells, were reasonably and prudently incurred." She added that in the 2017 rate case, the Company had sought recovery of land acquisition costs at Cape Fear and H.F. Lee, that the Public Staff did not recommend a disallowance of those costs, and that those costs were approved by the Commission. (Id. at 130-31.)

She disagreed with Public Staff witness Lucas' contention that the cost of extraction wells and treatment at Asheville and Sutton should be disallowed because such costs would not have been necessary under CAMA without violations of the state groundwater standards. (Id. at 131.) Witness Bednarcik testified that "[b]ecause the measures undertaken at the DEP sites were reflected in the Sutton Settlement Agreement, they were moved up in time from when they would have otherwise been required, but DE Progress would have installed extraction wells to comply with CAMA even without the Sutton Settlement Agreement." (Id.) She also referenced language from the Sub 1142 Order that stated, "the assertion that DE Progress' 'violations' resulted in the [Sutton Settlement Agreement] and in groundwater extraction and treatment costs that would not otherwise have been incurred is incorrect and not supported by the evidence." (Id. at 132.) Witness Bednarcik further asserted that witness Lucas' reliance on the fact that groundwater exceedances measured at the DEP sites have increased since the late case was "indicative of a basic misunderstanding of the 2L exceedance/violation process." (Id.) Witness Bednarcik concluded that an increase in 2L exceedances does not suggest an increase in groundwater contamination around the DEP plants, but rather is to be expected and shows ongoing sampling and compliance with CAMA. (Id. at 132-33.)

On cross-examination, witness Bednarcik was asked whether CAMA or the CCR rule would have required groundwater extraction and treatment at the Asheville and Sutton plants if the Company did not have exceedances at or beyond the compliance boundary at those sites. Witness Bednarcik conceded that the extraction wells and treatment were "because of the exceedances beyond the compliance boundary." (Id. at 412.) Furthermore, witness Bednarcik agreed that, in general, groundwater and the constituents carried in groundwater flow through and past monitoring wells over time. When asked to confirm that sampling groundwater at the same well over time does not equate to sampling the same water over and over again, she responded that "it depends on when you do the sampling and the flow rate of that specific site." (Id. at 168.)

Witness Bednarcik was also asked about the land acquisition costs at the Mayo plant. She confirmed that a data request response provided by DEP to the Public Staff discussed the purchase of approximately 56 acres of property bordering the Mayo plant.[15] Witness Bednarcik was asked, with regard to the following passage, what specific risks the Company wanted to manage: "The property purchase allows Duke Energy to control activities on the property, thereby managing risks to property users downgradient of the Mayo ash basin to the North Carolina-Virginia state line." (Id. at 413-14.) Witness Bednarcik responded that the land purchase "allowed us to have a little bit more room on our compliance boundary," and "allowed just a little bit more distance between where other people who owned different property in proximity to our ash basin." (Id. at 414.) She stated that the risks were not related to groundwater, but rather to access and making sure DEP had a buffer around the basins. (Id. at 415.)

DISCUSSION AND CONCLUSION

With regard to groundwater extraction and treatment costs at Asheville and Sutton, the Commission is persuaded by the arguments made by the Public Staff in support of a disallowance. There is sufficient evidence to show that there were and continue to be exceedances of the 2L groundwater quality standards at or beyond the compliance boundary at both sites. There is also sufficient evidence to show that there were exceedances of the 2L groundwater quality standards at or beyond the compliance boundary at DEP's Mayo facility, where the Company

[15] Bednarcik Rebuttal Public Staff Cross Examination Exhibit 6.

purchased land to mitigate risks from its coal ash impoundment. For example, the Company's groundwater monitoring reports show exceedances of 2L groundwater quality standards at or beyond the compliance boundaries.[16] As shown in Lucas Exhibit 11, DEP has violated the regulatory limits for constituents listed in 2L and IMAC standards and federal maximum contaminant levels at the Asheville plant 1,685 times, at the Sutton plant 1,778 times, and at the Mayo plant 328 times. No party, including DEP, contested the number of groundwater exceedances presented by witness Lucas.

In addition, groundwater detection and assessment monitoring results submitted by DEP pursuant to the CCR Rule show exceedances of the groundwater protection standards.[17] The 2016, 2017, 2018, and 2019 Environmental Audit reports, summarized in Lucas Exhibit 13, also show groundwater exceedances at the Asheville, Sutton, and Mayo facilities, and indicate that the exceedances are due to the ash basins.[18] The Environmental Audit reports indicate exceedances of the following constituents at or beyond the compliance boundary: arsenic, boron, chromium, cobalt, iron, manganese, pH, selenium, sulfate, thallium, total dissolved solids, and vanadium. The Environmental Audits were conducted by independent consultants, reporting to Duke Energy and the Court Appointed Monitor, as a condition of the Company's federal probation. Furthermore, the Sutton Settlement Agreement stated that the Asheville and Sutton plants demonstrated off-site groundwater impacts.[19]

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[16] Lucas Exhibit 11.
[17] Lucas Exhibits 15-16.
[18] Lucas Exhibit 13.
[19] Bednarcik Direct DEP Redirect Examination Exhibit 2.

Importantly, the Commission notes that, as discussed earlier in this Order, DEQ has confirmed its position that an exceedance of the 2L standard at or beyond the compliance boundary constitutes a violation of the 2L rules.[20]

The wording in the Sutton Settlement Agreement makes clear the need to mitigate the impacts of contaminated groundwater coming from Duke Energy ash basins and impacting property adjacent to Duke Energy's plant sites:[21]

II. DUKE ENERGY'S OBLIGATIONS

A. Consistent with 15A NCAC 2L .0106 Duke Energy shall implement accelerated remediation at the Sutton Plant on the following terms and conditions:

(1) Duke Energy will commence installation of extraction wells on the eastern portion of the Sutton Plant property where data show constituents associated with the ash basins at concentrations over the 2L standards ("Constituents of Interest") have migrated off site.

(2) Extraction wells will be used to pump the groundwater to arrest the off-site extent of the migration. The pumped groundwater will be treated as needed to meet standards and returned either to the ash basin or the discharge canal.

(3) This extraction and treatment system will be installed as soon as practicable following receipt of all permits and approvals from DEQ, the issuance of which will occur as soon as practicable. This accelerated groundwater remediation is in addition to and shall be performed concurrent with the coal ash impoundment closure obligations set forth in CAMA.

(4) The extraction wells shall remain operational until such time as Duke Energy demonstrates through sampling, analysis, and appropriate modeling, and subject to DEQ's written concurrence, that off-property constituents of interest have been remediated to 2L Standards and there is no reasonable potential for future off-site migration.

(5) As part of accelerated remediation, DEQ agrees that dry ash can be removed from the head of the ash basins under a construction storm water permit and shall expedite such

[20] Lucas Exhibit 10.
[21] Bednarcik Direct DEP Redirect Examination Exhibit 2.

construction storm water permit in order for Duke Energy to commence the removal of ash which is the source of the constituents of interest from the Sutton Plant. DEQ will issue construction storm water permits for Sutton plant within 10 days of receiving Duke Energy's complete application. Only dry ash from the head of the ash basins will be removed with no impact to wastewater treatment or water levels in the basins. DEQ shall use its best efforts to complete the process of the issuance of the NPDES permit modification at the Sutton Plant to allow for the removal of water and ash beyond the areas covered under the construction storm water permit from the Sutton Plant.

B. Consistent with 15A NCAC 2L .0106 Duke Energy shall implement accelerated remediation at the Asheville Plant, Belews Creek Plant, and H.F. Lee Plant, which are the only three other Duke Energy facilities that demonstrated offsite groundwater impacts in isolated areas that are not impacting private wells in the Comprehensive Site Assessments conducted pursuant to CAMA. Such accelerated remediation shall be tailored to each facility's unique characteristics.

(Emphasis added.) The purpose of the extraction wells is to arrest the off-site spread of coal ash constituents, in exceedance of 2L standards, coming from the Asheville and Sutton plants, and DEP witness Bednarcik admitted during cross-examination that the extraction wells were needed because of groundwater contamination beyond the compliance boundary.

The Commission also agrees with the Public Staff that the land acquisition costs at Mayo should not be borne by ratepayers. As shown in Bednarcik Rebuttal Public Staff Cross Examination Exhibit 6, DEP has described its purchase of approximately 56 acres of property as "allow[ing] Duke Energy to control activities on the property, thereby managing risks to property users downgradient of the Mayo ash basin to the North Carolina/Virginia state line." The document further states that "Duke Energy's ownership of property mitigates potential future risk by controlling or eliminating potential exposure pathways associated with Site-related constituents of interest," and that, as a result of the land purchase, the compliance boundary for the Mayo impoundment was extended.[22] It is evident, despite witness Bednarcik's testimony to the contrary during the evidentiary hearing, that the risks contemplated by DEP were related to groundwater concerns stemming from the Company's coal ash basins. Indeed, witness Bednarcik's hearing testimony contradicted her rebuttal testimony, in which she stated that the land purchase was "to mitigate groundwater risks at Mayo." The costs incurred for the land acquisition at the Mayo plant were incurred to mitigate the risk of spreading groundwater contamination, and are attributable solely to DEP's violation of the state's groundwater standards. The Commission therefore concludes that such costs should be disallowed.

Based on the entire record, the Commission finds and concludes that the costs incurred of $1,240,328 at the Asheville and Sutton plants for groundwater extraction and treatment and at the Mayo plant for land purchases should be disallowed. There is clear evidence of violations of the state's groundwater quality standards at Asheville, Sutton, and Mayo, and DEP has admitted that the

[22] Likewise, the December 31, 2019 Corrective Action Plan Update for the Mayo facility describes the land purchase as a "proactive corrective action measure," and states the following: "Duke Energy owns the property downgradient from the Mayo ash basin dam to the North Carolina/Virginia state line. Ownership of the property allows Duke Energy to control activities, thereby managing risks for future property use. As a proactive corrective action measure, on August 23, 2019, Duke Energy purchased the approximately 56-acre parcel positioned on the north side of Mayo Lake Road. Duke Energy-owned property bordered the acquired parcel on the west, south, and east sides. As a result of this acquisition, the ash basin compliance boundary has been revised. The compliance boundary now extends further to the north beyond Mayo Lake Road and 500 feet from the entire waste boundary (Figure ES-1)." December 31, 2019 Corrective Action Plan Update for the Mayo Steam Electric Plant at ES-12.

groundwater extraction wells were installed because of exceedances beyond the compliance boundary. Furthermore, these violations resulted in costs that would not otherwise have occurred under CAMA or the CCR Rule. Likewise, the costs incurred for the land acquisition at Mayo are due solely to DEP's violation of the state's groundwater standards, and would not have been incurred if DEP had not violated those standards. The Commission is persuaded that it would be unreasonable to charge ratepayers for costs of environmental violations over and above the costs required to comply with CAMA in the absence of environmental violations.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence supporting this finding of fact and conclusions is contained in the Application, Form E-1, the testimony of public witnesses, and the testimony and exhibits of DEP witnesses Jessica L. Bednarcik, James Wells, and Marcia E. Williams, Public Staff witnesses Jay B. Lucas, Michelle M. Boswell, and Michael C. Maness, AGO witness Steven C. Hart, Sierra Club witness Mark Quarles, and CUCA witness Kevin W. O'Donnell.

Summary of the Evidence

DEP DIRECT TESTIMONY

In her direct testimony, DEP witness Jessica Bednarcik testified that from September 2016 to July 2018, she held the position of Special Assignment Leader in the Environmental, Health and Safety department and managed the provision of permanent water required by CAMA. (Tr. vol. 12, 32.) She testified that DEP is seeking recovery of CCR expenses incurred from September 1, 2017 through June 30, 2019, and costs to be incurred through February 29, 2020, related to reasonable, prudent, and cost-effective approaches to complying with applicable regulatory requirements. (Id. at 33.) Witness Bednarcik testified that the 2016 CAMA amendments required the Company to provide permanent replacement water supplies to all homeowners with drinking water supply wells located within a one-half mile radius of the compliance boundaries of each of the Company's coal ash impoundments. She added that CAMA provided a preference for permanent replacement water supplies by connection to public water systems, as opposed to the installation of filtration systems. CAMA provided, however, that homeowners may elect to receive filtration systems, and that DEQ may determine that connection to a public water supply to a particular household would be cost prohibitive, resulting in the installation of a filtration system. (Id. at 39.)

Witness Bednarcik testified that to comply with CAMA, DEP has incurred costs for permanent water supplies, including costs for "the planning, design, and installation of municipal water mains and/or service lines, the planning, design and installation of water treatment systems, taxes and fees for permitting and connection of the water lines and water treatment systems, and delivery of bottled water." (Id. at 45.) Costs also included communications to homeowners and the development of reports required by DEQ to certify completion of the provision of permanent water supplies. (Id.)

INTERVENOR TESTIMONY

Public Staff witness Lucas recommended disallowance of recovery in rates for the costs to provide bottled water and permanent alternative water supplies to neighboring properties. Witness Lucas first testified that the Public Staff had confirmed that the expenditures for bottled water provided to households in the vicinity of DEP plants during the period of September 2017 through December 2019, in the amount of $395,005 on a system basis, including the bottled water itself, the delivery company, personnel associated with the delivery, and the consulting firm that managed the overall bottled water delivery program, had been excluded by DEP in its pro forma adjustment set forth in the E-1, Item 10, NC-1103. He stated that the adjustment aligned with the Commission's decision to disallow such costs in the Sub 1142 rate case. (Tr. vol. 15, 1503.)

With regard to permanent alternative water supplies, witness Lucas testified that the Company was required to connect eligible residential properties to municipal water systems per N.C.G.S. §130A-309.211(c1). He recommended that the costs for the period of September 2017 through December 2019, in the amount of $1,087,612 on a system basis, be disallowed by exclusion from DEP's pro forma adjustment set forth in the E-1, Item 10, NC-1103. (Id. at 1503-04.) In his supplemental testimony, witness Lucas explained that additional costs of $18,016 were incurred by the Company for connections to municipal water systems in January and February of 2020, and recommended that those costs likewise be disallowed. (Id. at 1529-30.)

Witness Lucas further testified that as an alternative to connections to municipal water systems, N.C.G.S. §130A-309.211(c1) allowed for the installation, operation, and maintenance of water treatment systems. Witness Lucas recommended that the costs for the period of September 2017 through December 2019, in the amount of $2,774,583 on a system basis be disallowed. (Id. at 1504-05.) In his supplemental testimony, witness Lucas explained that additional costs of $72,390 were incurred by the Company for water filtration systems in January and February of 2020, and recommended that those costs likewise be disallowed. (Id. at 1529-30.)

Lastly, witness Lucas testified that the Company had voluntarily connected businesses and residential properties that were otherwise not eligible under CAMA to permanent alternative water supplies. Witness Lucas explained that the Company had excluded the voluntary costs from the rate request, and he therefore stated that no adjustments with regard to those voluntary connections were necessary. (Id. at 1504.)

Witness Lucas asserted that the costs for permanent alternative water supplies—both the public water supply connections and the filtration systems—and bottled water supplies were the direct result of the legislature deciding that coal ash constituents from DEP's impoundments created an unacceptable risk to people's groundwater wells in the vicinity of the coal ash impoundments. He noted that in the last rate case, the Commission had determined that the costs for bottled water supplies should be disallowed. He further referenced Commissioner Clodfelter's dissent in the Order in DEC's 2017 rate case, in which Commissioner

Clodfelter stated that, like the bottled water costs, costs for permanent alternative water supplies should be disallowed. (Id. at 1504.)

As discussed in greater detail earlier in this Order, witness Lucas provided evidence in his testimony of violations of state and federal laws and regulations that have resulted from DEP's management of its impoundments, including, but not limited to, federal criminal negligence, unlawful surface water discharges in violation of N.C.G.S. § 143-215.1, and exceedances of groundwater quality standards at all of DEP's coal ash sites. (Id. at 1485-93.)

Witness Lucas testified in summary that the costs to connect eligible residential properties to permanent alternative water supplies and, alternatively, the installation, operation, and maintenance of water treatment systems, as required by CAMA, should be excluded from rate recovery. He stated that these costs are the direct result of the legislature deciding that DEP's coal ash management had created an unacceptable risk to people's groundwater wells in the vicinity of the impoundments. He testified that the permanent alternative water supplies serve the same purpose as bottled water—protecting neighbors surrounding the coal ash impoundments from contamination risks—and therefore should be excluded from cost recovery just as bottled water costs have been excluded. (Id. at 1536.)

AGO witness Hart testified that the requirement under CAMA to connect all households to alternate water supplies was likely a result of DEP's delay in addressing groundwater impacts. He asserted that it is "unheard of for a company to have to connect properties to alternate water when those water supplies are not impacted." (Tr. vol. 13, 694.) Witness Hart stated that he believed the water supplies were "warranted by law because DEP, once it knew it had groundwater issues, had failed to determine the extent of groundwater impacts, reliably establish background concentrations, and perform adequate receptor evaluations." (Id. at 694-95.) He testified that, DEP instead "contended that there were few if any water supply well receptors in the area of its facilities and maintained that position despite there being no indication that it performed comprehensive receptor surveys until required to do so under CAMA." (Id. at 695.) Witness Hart concluded that the permanent water supply costs were directly related to DEP's delay in evaluating groundwater impacts and, therefore, recommended that the related costs in the amount of $3,481,096be disallowed. (Id.)

Sierra Club witness Quarles testified that "[i]n numerous cases, rather than initiating corrective actions to eliminate or mitigate the [groundwater] contamination, Duke Energy companies have responded by purchasing affected properties or providing alternative drinking water sources." (Tr. vol. 14, 612.) He then provided several examples:

> At the Sutton site, [DEP] removed four public drinking water wells from service and provided an alternative supply. At the H.F. Lee site, [DEP] purchased some of the land within 500 feet of the site because of migrating contamination. At the Mayo site, [DEP] purchased property immediately downgradient of its ash basin. . . . Both DEC and DEP have provided bottled water to residents near ash sites.

(Id. at 612-13.)

Witness Quarles testified in summary that DEP's "inaction resulted in more widespread contamination of the state's groundwater resources, jeopardy to present and future drinking water sources, the need for alternative drinking water supplies, and millions of tons more ash to be dewatered, excavated, and redisposed of, all driving higher cleanup and risk reduction costs." (Id. at 627.)

CUCA witness O'Donnell testified that the Commission should disallow the incremental costs associated with CAMA versus the federal CCR Rule. (Tr. vol. 14, 133.)

DEP REBUTTAL TESTIMONY

In her rebuttal testimony, DEP witness Bednarcik testified that N.C.G.S. § 130A-309.211(c1) required DEP to establish permanent replacement water supplies for each household that has a drinking water supply well located within a one-half mile radius of the established compliance boundary of a coal ash impoundment, and that the replacement water supply can be achieved either through a connection to public water supplies or, in certain circumstances, through the installation of a filtration system. Witness Bednarcik further testified that this requirement exists even absent the existence of a 2L exceedance for qualifying households, and that it also applies to households outside the half-mile radius where exceedances are identified. (Tr. vol. 17, 133-34.)

Witness Bednarcik noted that Public Staff witness Lucas "argues that the permanent alternative water supply expenses are analogous to the costs the Company incurred to provide temporary bottled water supplies to customers and should, therefore, be disallowed." (Id. at 134.) She contended that the Commission had the opportunity to deny recovery of the permanent water supply costs in the 2017 rate case on the same grounds as the temporary bottled water costs, but that the Commission's decision to grant rate recovery of such costs in that case shows that the expenses were incurred to comply with CAMA and are equally appropriate for recovery in the present rate case. (Id. at 134-35.)

In response to AGO witness Hart's testimony that the permanent replacement water supply requirements under N.C.G.S. § 130A-309.211(c1) were likely enacted in response to DEP's delay in addressing groundwater impacts, witness Bednarcik testified that subsection (c1) was enacted as an amendment to CAMA in July 2016, less than two years after the General Assembly passed CAMA. She added that it was "nonsensical to suggest that the Company delayed taking action following the passage of CAMA," because CAMA contains detailed provisions for corrective action, including addressing any groundwater impacts, and requires that any such action must first be reviewed and approved by DEQ. (Id. at 135.) Witness Bednarcik testified that "history demonstrates that the environmental regulatory regime is an ever-evolving body of law, and it would be impossible to connect CAMA or any of its provisions to any singular underlying act." (Id.)

On cross-examination, witness Bednarcik testified that the provision of permanent water supplies pursuant to CAMA is not contingent upon an exceedance at the homeowner's well. (Id. at 170.) Regarding the groundwater quality of neighboring homeowners, she stated that the groundwater models and data do not indicate a risk. (Id. at 172.) Witness Bednarcik testified that there was a lot of groundwater data being collected and shared with DEQ prior to the CAMA amendments in 2016, and that background levels at each of the sites were being evaluated by DEQ “during the 2014/2015 time period,” but that she did not know if or when background concentration levels were established and approved. (Id. at 173.)

In his rebuttal testimony, DEP witness Wells testified that groundwater contamination at the DEP sites “does not threaten human health and safety.” (Tr. vol. 19, 185.) He further testified that “exceedances are almost entirely confined to DE Progress’ property, close to the basins.” (Id. at 185.)

In her rebuttal testimony, DEP witness Marcia Williams testified that AGO witness Hart “without justification” recommended removal of the costs for permanent water supply connections. (Id. at 322.) She further contended that it was “speculative and not supported by evidence or experience” for witness Hart to conclude that “earlier action by DE Progress would have led to a different remedial outcome, including the requirement to provide alternative water supply.” (Id. at 322-23.)

Discussion and Conclusions

With regard to the permanent alternative water supply and treatment system costs, the Commission is persuaded by the arguments made by intervenors in support of a disallowance. As discussed in greater detail in the Evidence and Conclusions for Findings of Fact Nos. 7 and 8, there is sufficient evidence to show that there were and continue to be exceedances of the 2L groundwater quality standards at or beyond the compliance boundary at DEP's active and retired coal-fired power plants. The requirement to provide permanent alternative water supplies to neighboring households is meant to protect those neighbors from risks presented by the groundwater contamination stemming from DEP's coal ash impoundments, which is expected to take years to remediate.

The Commission is persuaded that the North Carolina legislature passed the CAMA amendment requiring the provision of alternative water supplies in order to protect neighboring homeowners from the risks posed by the groundwater contamination caused by DEP's coal ash impoundments. Regardless of whether such contamination has or will reach nearby groundwater wells, the fact remains that a requirement to provide permanent alternative water supplies would not exist were it not for the Company's groundwater contamination, which extends beyond the compliance boundary in violation of the state's 2L rules at all but one of the Company's active and retired coal-fired power plants. The exception is the Mayo plant, which did have exceedances beyond the compliance boundary prior to its August 2019 purchase of additional land and the resulting extension of its compliance boundary.[23] The Commission is also of the opinion that its rationale behind disallowing the costs of bottled water in the last rate case applies in the same manner to the permanent alternative water supply costs recommended for disallowance in the current proceeding, and that, just as bottled water costs were

[23] Lucas Exhibits 11 and 13.

disallowed, permanent alternative water supply costs should be disallowed, as well.

Based on the entire record, the Commission finds and concludes that it would be unreasonable to charge ratepayers for the costs of permanent alternative water supplies and treatment systems. The specific costs identified in this case are $1,105,628[24] for public water supply connections and $2,846,973[25] for water filtration systems, for a total of $3,952,601 on a system basis, and the Commission finds that these costs should be disallowed. These costs have been incurred as a result of the North Carolina legislature mandating the provision of alternative water supplies in order to protect neighboring homeowners from the groundwater contamination from DEP's coal ash impoundments, and it would be unreasonable to place these water supply costs on ratepayers. Just as the Commission denied cost recovery for bottled water costs in the last rate case proceeding, the Commission now denies recovery of the costs associated with the provision of permanent alternative water supplies.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10-12

The evidence for these findings of fact and conclusions is found in the Company's Application, Form E-1, and the testimony and exhibits of DEP witness Bednarcik and Public Staff witnesses Garrett and Maness.

[24] This amount represents the $1,087,612 presented in the direct testimony of witness Lucas for the period of September 2017 through December 2019, in addition to the $18,016 presented in the supplemental testimony of witness Lucas for the period of January and February 2020.

[25] This amount represents the $2,774,583 presented in the direct testimony of witness Lucas for the period of September 2017 through December 2019, in addition to the $72,390 presented in the supplemental testimony of witness Lucas for the period of January and February 2020.

Summary of the Evidence

DEP DIRECT TESTIMONY

DEP witness Bednarcik is the Vice President of Coal Combustion Products, Operations, Maintenance and Governance for DEBS. She has held the position since 2019. (Tr. vol. 12, 31-32.) Witness Bednarcik testified on cross-examination that she did not have any first-hand experience with the negotiation of the Charah Master Contract. (Id. at 65-66.)

In her direct testimony, witness Bednarcik stated that in 2014 Duke Energy executed a contract with Charah to dispose of coal ash from DEC's Riverbend site and DEP's Sutton, Cape Fear, H.F. Lee, and Weatherspoon sites. According to witness Bednarcik, the contract required Duke Energy to provide a "minimum amount" of coal ash to be disposed of by Charah. Witness Bednarcik further testified that, as a result of amendments to the CAMA, Duke Energy altered its closure strategy after entering into the Charah Master Contract and, therefore, did not send the amount of ash contracted for. Witness Bednarcik testified that this resulted in the termination of the Charah Master Contract which, in turn, led Duke Energy to incur a fulfillment fee of $80 million, $33,670,054 of which was allocated to DEP for costs incurred and anticipated to be incurred by Charah associated with ash from its Cape Fear, H.F. Lee, and Weatherspoon sites. (Id. at 51-52.)

Witness Bednarcik opined that it was reasonable and prudent for DEP to enter into a contract with Charah that could result in the imposition of a fulfillment fee. She testified that, it is "common and reasonable" to require a "minimum investment from the company receiving the service" where an agreement requires a contractor to develop large infrastructure and that Charah's "infrastructure arrangements" in the context of the Charah Master Contract included purchasing land, permitting, rail construction, and landfill and leachate system construction. (Id. at 52.)

INTERVENOR TESTIMONY

Public Staff witness L. Bernard Garrett is a licensed professional engineer. He has 30 years of experience engineering coal ash management projects and has performed services such as landfill design, permitting, and construction, and landfill closure design, permitting, and construction. (Tr. vol. 15, 1217.)

On behalf of the Public Staff, witness Garrett investigated the prudence and reasonableness of the costs DEP incurred at its two high-priority sites, Sutton and Asheville, by reviewing the testimony and work papers of DEP witnesses Bednarcik, Smith, and Turner, conducting discovery regarding the actions taken and costs incurred by the Company at its high-priority sites, and participating in site visits and conference calls with DEP personnel. Based on his investigation, witness Garrett recommended that the Commission disallow $33,670,054 in costs DEP seeks to recover related to the fulfillment fee the Company paid to Charah. (Id. at 1219-22.)

In his testimony, witness Garrett engaged in an in-depth analysis of the Charah Master Contract. He opined that Duke Energy was not financially committed to Charah at the time it executed the contract and cited several excerpts from the contract in support, including the following excerpts from page one of the contract and Section 2.2 on page B-6 of Exhibit B to the contract, respectively:

[BEGIN CONFIDENTIAL]

[redacted]

[redacted]

[END CONFIDENTIAL]

(Id. at 1225; emphasis in original.)

Witness Garrett testified that it was not until Duke Energy issued Purchase Order **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]. **[END CONFIDENTIAL]** Witness Garrett testified that the Company was not financially committed for ash to be disposed of at the Sanford Mine, because no purchase order was issued for ash to be disposed of there. (Id. at 1226-27.)

Witness Garrett explained that the Termination provisions of the Charah Master Contract became effective on May 29, 2019, and that as of that date, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** were delivered. (Id. at 1228-29.)

[BEGIN CONFIDENTIAL] [redacted]

[END CONFIDENTIAL] (Ex. vol. 15, Confidential Garrett Exhibit 1.) Witness Garrett testified that the Prorated Costs referenced in the Termination provisions were calculated using two components: **[BEGIN CONFIDENTIAL]** [redacted]

[redacted].

[END CONFIDENTIAL] (Tr. vol. 15, 1230-31.)

Witness Garrett testified that the part of the definition of **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]. **[END CONFIDENTIAL]** (Id. at 1233-34.)

When asked on cross-examination during the E-7, Sub 1214, Rate Case hearing whether the sentence in **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[redacted]

[redacted] **[END CONFIDENTIAL]** (Id. at 1353-59.)

Witness Garrett opined that in order for the calculation of the Prorated Percentage to "achieve the intended and reasonable purpose" of compensating Charah for the costs it incurred to perform under the contract the denominator used to calculate the Prorated Percentage should be the quantity of ash authorized by purchase orders. Based on this opinion and the quantity of ash authorized to be disposed of by actual purchase orders, witness Garrett performed the following alternative Prorated Percentage calculation: **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Applying his alternative Prorated Percentage calculation to development costs[26] which he calculated to be **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** (Id. at 1234-35.) Witness Garrett testified that he would allocate all of the Prorated Costs to the DEC's Riverbend Station because **[BEGIN CONFIDENTIAL]** [redacted]

[26] See Ex. vol. 20, Confidential Garrett Exhibit 2.

[redacted]. **[END CONFIDENTIAL]** He noted that no purchase orders were issued for ash to be delivered from DEP's Cape Fear, H.F. Lee, or Weatherspoon Stations. Witness Garrett recommended that the fulfillment fee included in the ARO costs be reduced from $33,670,054, the portion of the fulfillment fee allocated to DEP, to $0.00. (Id. at 1235-36.)

Witness Garrett testified that upon termination of the Charah Master Contract, Duke Energy did not follow the pricing methodology established in the Charah Master Contract. Rather, Duke Energy asked Charah to supply the land acquisition, development, closure, post-closure monitoring, and leachate collection and disposal costs, if any, for which it sought reimbursement, which Charah asserted totaled **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** Witness Garrett further testified that it appeared Duke Energy had reviewed and excluded some of the costs supplied by Charah on the basis they were not development-related, and arrived at a total of **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** He stated that the significant disparity between the costs asserted by Charah and those arrived at by Duke Energy was "evidence of the significant flaws in the Termination provisions of [the Charah Master Contract] and of the unreasonableness and imprudence of Duke Energy's execution of the contract." (Id. at 1238-39.) On cross-examination during the E-7, Sub 1214, Rate Case hearing **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]** (Id. at 1361.)

Witness Garrett reviewed each “Permit to Operate, Approval to Commence Operations” issued by DEQ for the development and operations at the Brickhaven Mine and the “Partial Closure Notifications” submitted by Charah to DEQ. Based on those documents, witness Garrett determined that Charah developed Brickhaven “only as reasonably necessary to accommodate the phased ash volumes authorized under the applicable purchase orders” and did not incur costs before purchase orders were issued. Witness Garrett also determined based on his analysis and his expert, professional judgment that $82,313,644 was a reasonable cost for the work Charah completed at the Brickhaven Mine that was reimbursable under the Development portion of the Unloading/Development/Placement $/ton price set out in the Charah Master Contract. Witness Garrett testified, “Given that Charah was paid approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** under the development portion of the Unloading/Development/Placement $/ton price, I conclude that Charah was reasonably reimbursed for the actual development cost incurred at Brickhaven under the Development portion of the Unloading/Development/Placement $/ton price in the purchase orders.” (Id. at 1243-1245.) As an alternative, and assuming the Commission gave substantial weight to the settlement and Prorated Costs calculations of Duke Energy and Charah, applying the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Prorated Percentage calculated by the Company, which he found to be unreasonably high, to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, the development costs he calculated in Confidential Garrett Exhibit 2, witness Garrett concluded that the fulfillment fee should equal the following Prorated Costs calculation: **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. (Id. at 1246.)

Witness Garrett indicated that, if the Commission gave substantial weight to Duke Energy's settlement and Prorated Costs calculation, the portion of the fulfillment fee allocated to DEP should be calculated using the methodology illustrated in Confidential Garrett Exhibit 10, which was the methodology "used consistently by Duke Energy in its alternatives evaluations to select closure methods for the intermediate and low-priority sites and its ARO cost projections in the E-2, Sub 1142 rate case, prior to the settlement of the [P]rorated [C]osts." (Id. at 1247.) Using this allocation methodology, witness Garrett determined that the ARO costs in this proceeding would increase from $33,670,054 to $53,033,497. (Id. at 1250.) Witness Garrett explained that DEP had calculated the portion of the fulfillment fee it was seeking to recover using a different allocation methodology set out in Confidential Garrett Exhibit 5. Witness Garrett testified that this allocation methodology "appear[ed] to have been formulated to result in a more even allocation of the fulfillment fee settlement amount between DEC and DEP customers." (Id. at 1249.) He identified several flaws with both allocation methodologies utilized by the Company, including that it was unreasonable to allocate a portion of the fulfillment fee to the Company's Cape Fear Station when no purchase orders were issued for ash from that site to be disposed of at Brickhaven, and that it was unreasonable to allocate over $10 million to the Company's H.F. Lee and Weatherspoon Stations for closure and post-closure costs when the Sanford Mine was not developed. (Id.)

On redirect-examination during the E-7, Sub 1214, Rate Case hearing, witness Garrett testified that **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[redacted]

[END CONFIDENTIAL] (Id. at 1380-81.)

DEP REBUTTAL TESTIMONY

In her prefiled rebuttal testimony, DEP witness Bednarcik provided an explanation of Duke Energy and Charah's decision to include the fulfillment fee provisions in the Charah Master Contract. She stated, as she did in her prefiled direct testimony, that the Charah Master Contract required Duke Energy to "provide a minimum amount of coal ash for disposal at Charah's Brickhaven and Sanford Clay Mines." She asserted that "This arrangement reflected the fact that Charah, at the time of contracting, did not own sufficient land to accommodate the ash it was being engaged to manage." She testified that **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[redacted] **[END CONFIDENTIAL]** (Id. at 89.)

Witness Bednarcik testified that "the Company's contractual duty to pay Prorated Cost . . . . could be triggered by the issuance of a purchase order for transfer of ash to *either* Brickhaven *or* Sanford." (Id. at 92; emphasis in original.) She further testified that, "In any event, costs related to Sanford made up only approximately 12% of the total fulfillment fee." (Id.) On cross-examination by the Public Staff regarding the allocation of prorated costs from the Sanford Clay Mine, witness Bednarcik agreed that the Company did not send any ash to that site, yet 12%or $9.6 million of the total fulfillment fee was attributable to the Sanford Clay Mine site. She further testified that Charah incurred costs to purchase the property and there are "requirements" for a mine site. When asked whether she considered $9.6 million in costs to be insignificant, she responded, "So whether it's significant, insignificant, it is what it is." (Id. at 438-40.)

In response to witness Garrett's proposal that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** witness Bednarcik testified, "while Mr. Garrett is correct that DE Progress was not financially committed to provide Charah with quantities of ash for *excavation* beyond those identified in the purchase orders, the Company was still financially obligated to make Charah whole for [P]rorated [C]osts per the [P]rorated [C]ost [T]riggering [E]vent definition in the Master Contract." She further testified that **[BEGIN CONFIDENTIAL]**

[redacted]

[END CONFIDENTIAL] (Id. at 93-94; emphasis in original.)

Witness Bednarcik testified that, for contracts that require a contractor to invest a large amount of capital in order to be able to perform its obligations under the contract, it is common practice to include fulfillment fee-related terms and conditions. (Id. at 95.) However, on cross-examination, when confronted with the response to discovery served by the Public Staff requesting examples of projects other than the Brickhaven and Sanford structural fill projects that have required a minimum investment, witness Bednarcik agreed that DEP provided just one example in response. Witness Bednarcik further agreed that the example provided, **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[END CONFIDENTIAL] (Id. at 454-56.)

Witness Bednarcik testified that Duke Energy' inclusion of a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** (Id. at 98.) On cross-examination, witness Bednarcik testified **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** (Id. at 267-68.) Witness Bednarcik acknowledged that **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]** (Id. at 211-12.)

Witness Bednarcik further testified on cross-examination that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** She added that, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** (Id. at 215.) Regarding **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** (Id. at 236-37.)

Witness Bednarcik was asked on cross-examination **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[27] Ex. vol. 19 – Confidential, DEP Bednarcik Confidential Rebuttal Exhibit 1.

[redacted]

[END CONFIDENTIAL] (Id. at 216-18.)

Witness Bednarcik was also asked on cross-examination **[BEGIN CONFIDENTIAL]** [redacted][29] **[END CONFIDENTIAL]** (Id. at 227.)

[28] Ex. vol. 15 – Confidential.

[29] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

When asked on cross-examination **[BEGIN CONFIDENTIAL]** [redacted][30] **[END CONFIDENTIAL]** (Id. at 228-29.)

Witness Bednarcik testified on several occasions during her cross-examination that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** (Id. at 212, 232.)

On cross-examination during the E-7, Sub 1214, Rate Case hearing, witness Bednarcik was presented with **[BEGIN CONFIDENTIAL]** [redacted]

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[30] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

[redacted]

[redacted]

[END CONFIDENTIAL] (Id. at 259-63.)

On cross-examination, witness Bednarcik was presented with **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** (Id. at 456-59.)

In response to questions from the Commission, witness Bednarcik acknowledged **[BEGIN CONFIDENTIAL]** [redacted]

[END CONFIDENTIAL] (Id. at 295-96.) Witness Bednarcik also agreed that **[BEGIN CONFIDENTIAL]** [redacted]

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[31] Ex. vol. 15 - Confidential.

[32] DEC Ex. vol. 20 – Confidential, Garrett Confidential Exhibit 6.

[33] DEC Ex. vol. 20 – Confidential, Garret Confidential Exhibit 5.

[redacted] **[END CONFIDENTIAL]** (Id. at 309.)

COMMISSION REVIEW OF EVIDENCE AND CONCLUSIONS

The Commission in this proceeding is asked to address the reasonableness and prudence of DEP's coal ash costs. Unreasonable costs, which may include costs resulting from imprudence, are properly disallowed under N.C.G.S. § 62-133(b). The Commission has stated the prudence standard as follows:

> the standard for determining the prudence of the Company's actions should be whether management decisions were made in a reasonable manner and at an appropriate time on the basis of what was reasonably known or reasonably should have been known at that time. The Commission agrees that this is the appropriate standard to be used in judging the various claims of imprudence that have been put forth in this proceeding . . . and adopts it as the standard to be applied herein. The Commission notes that this standard is one of reasonableness that must be based on a contemporaneous view of the action or decision under question. Perfection is not required. Hindsight analysis -- the judging of events based on subsequent developments — is not permitted.

78 North Carolina Utilities Commission Report, 238 at 251-52 (1988).

Under prevailing procedural and evidentiary standards, the Company's expenditures should be presumed to be reasonable and prudent until an objecting party provides evidence suggesting to the contrary, at which point the Company bears the burden of proof to substantiate the reasonableness of the expenditures. When the matter under review involves the reasonableness and prudence of a known and discrete expenditure made at a definite point in time, it is appropriate to require that parties challenging that expenditure come forward with some evidence that reasonable alternatives were available and to quantify the amount of the alleged error. *See State of North Carolina ex rel. Utilities Commission v. Conservation Council of North Carolina,* 312 N.C. 59, 320 S.E.2d 679 (1984).

Prudence of Charah Fulfillment Fee

Public Staff witness Garrett's general premise is that DEBS acted unreasonably and imprudently when, as agent for and on the behalf of the Companies, it entered into a contract with Charah for the disposal of coal ash from its Riverbend Station at the Brickhaven Mine. Specifically, witness Garrett concluded that the Termination provisions of the contract, most significantly, a Prorated Percentage calculation, contained fundamental flaws and ambiguities that resulted in DEP paying an unreasonable and imprudent fulfillment fee, which was determined through settlement negotiations, not the contract provisions.

Witness Garrett based his conclusion on his 30 years of experience engineering coal ash management projects, and his thorough analysis of the Charah Master Contract and subsequent amendments, purchase orders issued by Duke Energy, documents issued by DEQ, and documents submitted by Charah to DEQ, among other sources.

Witness Garrett determined through his analysis of Permits to Operate issued by DEQ and Partial Closure Notifications submitted by Charah to DEQ that $82,313,644 was a reasonable cost for the work Charah completed at the Brickhaven Mine that was reimbursable under the Development portion of the Unloading/Development/Placement $/ton price set out in the Charah Master

Contract. Based on his calculation of the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Based on his understanding that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Witness Garrett testified that he **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]**

On cross-examination during her live testimony, witness Bednarcik testified for the first time in the proceeding that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Both witness Garrett and witness Bednarcik testified that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

The Commission gives greater weight to the testimony of Public Staff witness Garrett than to that of DEP witness Bednarcik. In reaching this determination, the Commission recognizes witness Garrett's extensive experience engineering coal ash management projects, and his comprehensive analysis of the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** The Commission further notes that, by her own admission, witness Bednarcik did not have any first-hand experience with the negotiation of the Charah Master Contract. Furthermore, witness Bednarcik was unable to support several key assertions, including her assertion that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Based on the entire record, the Commission finds and concludes that Duke Energy's execution of the Charah Master Contract containing the Termination provisions, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** was unreasonable and imprudent and resulted in Duke Energy's payment of an unreasonable and imprudent fulfillment fee. The Commission finds and concludes that there were prudent and feasible alternatives available to Duke Energy that would have avoided the requirement that Duke Energy pay the $80 million fulfillment fee. For example, Duke Energy could have drafted the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** The Commission finds and concludes that it is appropriate that the Company bear the cost of $33,670,054 for its unreasonable and imprudent actions, as opposed to recovering those costs in rates and earning a return at the expense of ratepayers.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13-15

The evidence supporting these findings of fact and conclusions is found in the Application, Form E-1, and the testimony and exhibits of DEP witness Bednarcik and Public Staff witnesses Moore and Maness.

Summary of the Evidence

DEP DIRECT TESTIMONY

In her direct testimony, DEP witness Bednarcik testified that DEP is seeking recovery of CCR expenses incurred from September 1, 2017, through June 30, 2019, and costs to be incurred through February 29, 2020, related to what she contended were reasonable, prudent, and cost-effective approaches to comply with applicable regulatory requirements. (Tr. vol. 12, 33.) She stated that “Cape Fear and H.F. Lee were selected as two of three Duke Energy sites for the installation of a beneficiation project pursuant to CAMA.” Witness Bednarcik further testified that “DE Progress has contracted with SEFA to install its STAR technology to process the ash from Cape Fear and H.F. Lee.” (Id. at 49.) Witness Bednarcik acknowledged on cross-examination that she had only been in her position as Vice President of Coal Combustion Projects, Operations, Maintenance and Governance for approximately seven months when she filed her direct testimony in this proceeding and that she was not involved in the RFI for the technology for the beneficiation facilities or the Request for Proposals (RFP) for the engineering, procurement, and construction of the beneficiation facilities. (Id. at 65-67.)

Witness Bednarcik provided site details and a description of the work performed at the Cape Fear and H.F. Lee sites in Bednarcik Exhibits 13 and 14, which state, in part, “The tasks that DE Progress has performed and will perform from September 1, 2017 through February 29, 2020 are a continuation of the activities for which costs were approved in the prior DE Progress rate case,” and

"These activities and associated costs continue to be necessary, appropriate, and consistent with applicable regulatory requirements." (Ex. vol. 13, Bednarcik Exhibits 13 and 14.) Witness Bednarcik noted that DEP had incurred $33,341,762 and $73,427,305 in costs for Beneficiation Facility Construction at Cape Fear and H.F. Lee, respectively, between September 1, 2017, and June 30, 2019. (Tr. vol. 12, 51.) She concluded that the closure activities described in her testimony for each site were necessary to comply with regulatory obligations, described processes the Company utilized to ensure costs "are not exorbitant, unnecessary, wasteful, or extravagant," and stated that the Company has properly managed the activities to ensure compliance with appropriate deadlines. (Id. at 56-58.)

INTERVENOR TESTIMONY

On behalf of the Public Staff, witness Moore recommended a partial disallowance in the amount of $130,384,392 of costs incurred for the construction of the beneficiation facilities at Cape Fear and H.F. Lee Stations. (Tr. vol. 15, 1183.)

Witness Moore testified that in 2016 the North Carolina General Assembly amended CAMA, among other things, to add N.C.G.S. § 130A- 309.216 regarding ash beneficiation projects. He noted that part (a) states in part:

> On or before January 1, 2017, an impoundment owner shall (i) identify, at a minimum, impoundments at two sites located within the State with ash stored in the impoundments on that date that is suitable for processing for cementitious purposes and (ii) enter into a binding agreement for the installation and operation of an ash beneficiation project at each site capable of annually processing 1 300,000 tons of ash to specifications appropriate for cementitious

products, with all ash processed to be removed from the impoundment(s) located at the sites.

Part (b) requires Duke Energy to identify an additional beneficiation site on or before July 1, 2017, and part (c) sets the closure deadline for intermediate and low-risk impoundments at ash beneficiation sites as no later than December 31, 2029. (Id. at 1185-86.)

Witness Moore testified, "On August 11, 2016, Duke Energy Business Services, LLC, as an agent for and on behalf of DEC and DEP (Duke Energy), advertised the Request for Information (RFI) for the Beneficiation of Ponded Ash into Concrete Specification Ash." **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** (Id. at 1187-88.)

As shown in Confidential Moore Exhibit 2, SEFA's response to the RFI specifically named **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[END CONFIDENTIAL] (Id. at 1190-91.)

In response to a Public Staff data request, the Company clarified that SEFA provided a construction estimate for the STAR facility in the amount of $64 million in response to the RFI, which included “approximately $14.8M in SEFA engineering and Project Indirect cost, as well as $50.2M for [Engineering, Procurement, and Construction] Direct Construction cost and balance of plant procurement.” (Id. at 1189-90.) Witness Moore testified that the Company subsequently increased the construction cost estimate. The Company’s December 31, 2016, ARO cost spreadsheet, **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[redacted] **[END CONFIDENTIAL]** (Id. at 1191-93.)

Witness Moore testified that the Company did not contract with H&M for the construction of its beneficiation facilities. In response to a Public Staff data request in the E-7, Sub 1214, Rate Case proceeding, DEC indicated that **[BEGIN CONFIDENTIAL]** [redacted]

[redacted][34] **[END CONFIDENTIAL]** (Id. at 1193-94.)

Witness Moore testified that DEBS advertised an RFP for the engineering, procurement, and construction of the three beneficiation units dated **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** (Id. at 1195, 1197.)

[34] Ex. vol. 15, Confidential Moore Exhibit 4.

Witness Moore explained that, according to DEC's confidential response to data request served by the Public Staff in the E-7, Sub 1214, Rate Case, between the time SEFA submitted its response to the RFI and the awarding of the construction contracts to Zachry, in October 2017, the Duke Adjustments to Construction Base Estimate increased substantially from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Witness Moore added that DEP had indicated the spreadsheet for the Buck beneficiation facility also applied to the H.F. Lee and Cape Fear facilities. (Id. at 1198-99.)

On redirect-examination during the live hearing in the E-7, Sub 1214, Rate Case, witness Moore testified that, using the Company's responses to data requests, he had performed an analysis in summary table form which accurately compared the scope of work and facility components contemplated by the H&M estimate and the initial Zachry contract amount. Witness Moore explained that he accomplished this by removing or adding components identified by the Company

[35] Ex. vol. 15, Confidential Moore Exhibit 6.

as necessary to achieve comparable facilities.[36] As shown in Confidential Public Staff Garrett and Moore Redirect Exhibit 1,[37] the Company indicated in discovery responses that the H&M estimate included **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** (Id. at 1376-78.)

Witness Moore concluded that the Company's selection of Zachry to construct the beneficiation units at H.F. Lee and Cape Fear Stations for the amount contracted was not reasonable or prudent. In support of his conclusion, he testified:

> SEFA's response to the RFI recommended H&M because they had constructed similar facilities designed by SEFA. SEFA's response to the RFI included a cost estimate for H&M to construct the beneficiation unit for **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Readily available articles state that capital costs for SEFA's beneficiation unit at Winyah Station in South Carolina were approximately $40 million**. See Moore Exhibit 8**.
>
> . . . .

[36] On cross-examination during the Sub 1214, Rate Case live hearing, witness Bednarcik confirmed that the figures shown in the Confidential Public Staff Garrett & Moore Redirect Exhibit 1 were derived from the Company's response to Public Staff Data Request 231-19(c) on her prefiled rebuttal testimony. (Tr. vol. 17, 274-75.)

[37] DEC Ex. vol. 20.

> Duke Energy's selection of Zachry to construct its beneficiation units more than doubled the construction cost for each unit. The Company has failed to provide a credible justification for this significant increase. For these reasons, I do not believe Duke Energy's selection of Zachry to construct the beneficiation units and the Buck, H.F. Lee, and Cape Fear Stations for the amount contracted was reasonable and prudent.

(Id. at 1201-2, 1204.)

In response to witness Bednarcik's testimony in the E-7, Sub 1214, Rate Case proceeding that a comparison of Winyah and facilities being constructed for Duke was of "little or no instructive value" due to differences between the facilities, witness Moore testified that information provided by DEC in response to discovery served by the Public Staff suggested otherwise. For example, witness Moore pointed out that witness Bednarcik's rebuttal testimony stating "the Winyah plant is designed to produce 200,000 tons of ash product per year . . . while the Buck beneficiation unit must produce 300,000 tons of ash product per year" is inconsistent with the statement in SEFA's response to the Duke Energy RFI[38] that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** (Id. at 1202-03.) He also noted witness Bednarcik's contention that there are differences in the proportion of ponded ash processed at the Winyah facility and to be processed at the Company's facilities was contradicted by a paper[39] provided by DEC in response to a Public Staff data

[38] Ex. vol. 15, Confidential Moore Exhibit 2.

[39] Ex. vol. 15, Moore Exhibit 9.

request stating, “The [Winyah] plant routinely operates using 100% reclaimed coal ash from ponds . . . .” (Id. at 1203.)

As shown in Moore Exhibit 8, SEFA’s Vice President of Market Development and Research, Jimmy Knowles, indicated that $50 million represented the “high end of the price range for thermal facilities at large coal-fired plants.” The article quoted Knowles as stating, “The cited all-in cost above would be for a large plant, probably with a maximum feed rate of 500,000 tons per year,” and “The design for an ash beneficiation plant at any of the Duke Energy sites in NC would probably be similar in size.” (Ex. vol. 15.)

Witness Moore did not take issue with the Company’s decision to award the engineering contract to SEFA, the subsequent change orders submitted by SEFA and Zachry, or the costs associated with those change orders. (Tr. vol. 15, 1188-89, 1196-98.)

Witness Moore testified that when the Company received the construction estimate from Zachry and learned that the estimated cost for the STAR facilities would be far higher than originally estimated, it should have attempted to mitigate the costs. He testified that there were a number of feasible options available to the Company to achieve mitigation of costs, including the following: 1) sending the construction contract out for bid again to a broader group of companies, 2) entering into three separate contracts for the construction of one STAR facility each and further divided the construction of each STAR facility into separate contracts for the various components of each facility, 3) seeking statutory relief from the CAMA

Amendment's beneficiation requirements from the General Assembly,[40] and/or 4) seeking guidance from DEQ regarding the availability of a waiver or compromise, and the consequences of non-compliance with the beneficiation requirements of the CAMA Amendment. (Id. at 1204-06.)

Based on his determination that the Company's selection of Zachry to construct the beneficiation units at the Cape Fear and H.F. Lee Stations for the amounts contracted was unreasonable and imprudent, witness Moore recommended that the Commission disallow **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for the H.F. Lee beneficiation unit and **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for the Cape Fear beneficiation unit for a total of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** The disallowance amount for each beneficiation unit is the difference between the Company's reasonable expectation of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, which is the sum of H&M's cost estimate of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, and Zachry's overall estimated contract costs of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for construction of the H.F. Lee beneficiation unit and **[BEGIN CONFIDENTIAL]** [redacted] **[END**

[40] For example, "a statutory relief option exists in the context of the Renewable Energy and Energy Efficiency Portfolio Standard in NC. Gen. Stat. § 62-133.8(i)(2), and that DEC and other electric power suppliers have utilized this option multiple times to seek delays in certain requirements related to swine and poultry waste set asides upon a showing to the Commission that the electric power suppliers made a reasonable effort to meet the requirements, and it was in the public interest to grant the delay or modification."

CONFIDENTIAL] for construction of the Cape fear beneficiation unit. (Id. at 1208-09.)

On cross-examination by the Company during the E-7, Sub 1214, Rate Case, witness Moore was read the following excerpt from Confidential Moore Exhibit 2, SEFA's response to the RFI: **[BEGIN CONFIDENTIAL]**

> [redacted]
>
> . . . .
>
> [redacted]

[END CONFIDENTIAL] (Id. at 1331-32.) Witness Moore was also read the following excerpt from SEFA's RFI response: **[BEGIN CONFIDENTIAL]**

> [redacted]

[END CONFIDENTIAL] (Id. at 1344.) In response to the excerpts, witness Moore testified that the **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]** (Id. at 1345.)

Also on cross-examination during hearing in the Sub 1214, Rate Case, witness Moore was presented with the Affidavit of William R. Fedorka, Vice President of SEFA, which was filed as an exhibit to witness Bednarcik's rebuttal testimony in the DEP proceeding.[41] Witness Moore confirmed that the affidavit states the Winyah facility was intended to generate 250,000 tons per year of beneficiated fly ash per year, and that the original design specifications assumed 33% of the ash processed by the facility would be production ash, and 67% would be ponded ash. Witness Moore testified that he did not disagree that the Winyah facility was designed to the specifications stated in the affidavit, but he reiterated that both sources referenced in the exhibits to his testimony and SEFA's response to the Company's RFI indicate that the Winyah facility is capable of processing 100% ponded ash. On redirect-examination, witness Moore confirmed that, contrary to Mr. Fedorka's affidavit, SEFA's response to the RFI stated **[BEGIN CONFIDENTIAL]** [redacted]

[41] DEC Ex. vol. 20, DEC Garrett/Moore Cross Examination Exhibit 3 and DEP Ex. vol. 19, Bednarcik Rebuttal Exhibit 8.

[redacted] **[END CONFIDENTIAL]** (Id. at 1371-72.)

DEP REBUTTAL TESTIMONY

In her rebuttal testimony, DEP witness Bednarcik summarized Public Staff witness Moore's recommended disallowance of $130,384,392 for costs incurred by EPC subcontractor Zachry at the H.F. Lee and Cape Fear beneficiation sites, which he based on the estimate of project costs included in **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** She contended that the Company's selection of Zachry as the EPC contractor for the Buck beneficiation project was "reasonable, prudent, and supported by law," and that the Commission should therefore reject the disallowance. Witness Bednarcik disputed witness Moore's contention that, after receiving the estimate from Zachary, the Company should have taken a number of steps including sending the contract out to be rebid, entering into separate contracts for each of the three STAR facilities, seeking relief from CAMA, and seeking guidance from DEQ. She testified regarding the RFI that it did not request site-specific estimates of the EPC costs or provide project details necessary to calculate such estimates. She asserted that SEFA provided estimated costs based on the cost to construct the Winyah STAR facility. (Tr. vol. 17, 116-19.)

Witness Bednarcik testified that to comply with N.C. House Bill 630 § 130A-309.216, which required the Company to execute a binding agreement for the installation and operation of ash beneficiation projects by January 1, 2017, **[BEGIN CONFIDENTIAL]** [redacted].**[END CONFIDENTIAL]** (Id. at 119-21.)

Witness Bednarcik asserted that witness Moore had supported his disallowance with a comparison of the EPC costs at H.F. Lee and Cape fear to the costs for the construction of the Winyah STAR facility. She further asserted that this comparison was not instructive due to differences in the amount of ash to be produced annually by the respective facilities, which necessitated an additional external heat exchanger at H.F. Lee and Cape fear, differences in the composition of the ash, which necessitated the addition of a grinding circuit, the type of scrubbers and associated equipment required at the respective facilities, and the reuse at Winyah of part of an existing carbon burn-out facility. (Id. at 121-23.) In Footnote 7 to her prefiled rebuttal testimony, witness Bednarcik stated, “Mr. Moore suggests that SEFA expended only $40 million on capital costs from the Winyah Station. From what I can tell, however, his cost analysis is based on a single 2013 article from Waste 360 that neither provides a source for this number, nor gives any specificity as to what costs were included/excluded in the $40 million number.” (Id. at 122) On cross-examination by the Public Staff, witness Bednarcik was presented with a presentation by SEFA regarding the STAR beneficiation process dated 2014.[42] (Id. at 433.) Witness Bednarcik did not dispute that the presentation, which bears the name of Robert Erwin, Project Engineer with SEFA, stated “The SEFA group is building a $40 million facility to recycle high carbon fly ash produced by the power company Santee Cooper at its Winyah generating station in Georgetown, SC.” (Id. at 434-35.)

Witness Bednarcik disputed witness Moore’s assertion that her testimony was inaccurate as to the production capacity, proportion of ponded ash versus production ash utilized, and utilization of existing infrastructure at the Winyah facility. In support of her testimony, she offered the affidavit of Mr. Fedorka[43] which stated that the Winyah facility was designed to produce 250,000 tons of ash, that it operates on 67% ponded ash and 33% production ash, and that significant

[42] DEP Ex. vol. 19.

[43] DEC Ex. vol. 20, DEC Garrett/Moore Cross Examination Exhibit 3 and DEP Ex. vol. 19, Bednarcik Rebuttal Exhibit 8.

infrastructure from an existing facility was incorporated into the beneficiation facility. (Id. at 123-24.)

Witness Bednarcik acknowledged that witness Moore was correct that costs for a second external heat exchanger, dry scrubbers, and second bag house were included in Zachry's overall estimated contract cost. However, she asserted that a comparison of Zachry's estimate of $21.33 million for a second heat exchanger and grinding circuit to the overall H&M construction estimate of $50.8 million "helps to show the discrepancy between a screening estimate and costs based upon detailed engineering." (Id. at 124-25.)

Witness Bednarcik did not agree that the Company should have signed an EPC contract with SEFA. She testified that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** (Id. at 120.) In response to the contention that the Company should have sent the request for bids to a larger group of subcontractors, witness Bednarcik indicated that the Company sought to engage contractors it had experience with and **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** She noted that "it is now the defined policy of the state of North

Carolina for utilities to maximize the use of resident contractors for utility projects undertaken in the State of North Carolina, as stated in new NCUC Rule R25-1(a)" and that Zachry "maintains an industrial and power office in Charlotte. (Id. at 125-26.)

Regarding witness Moore's contention that the Company should have contracted with three separate contractors, witness Bednarcik responded that witness Moore provided no support that doing so would have lowered costs and that it was unclear whether SEFA could have supported three separate subcontractors at once and realized economies of scale. (Id. at 126.) She asserted that, if the Company had sought statutory relief as proposed by witness Moore, there was no guarantee that it would have been granted before the statutory deadline, if at all. She testified that N.C.G.S. § 130A-309.216, the section of the CAMA Amendment requiring beneficiation, makes no mention of the word "cost" and therefore it was "reasonable to conclude that the General Assembly did not intend for the costs of beneficiation to be considered in requiring the Company's environmental compliance." Furthermore, she opined "that it would be unreasonable to establish precedent in this state where utilities are granted 'relief' from adhering to environmental regulations meant to address identified risks on the basis of costs where such statutes do not already specifically contemplate costs."(Id. at 127-28.)

On cross-examination during the live hearing in the Sub 1214, Rate Case, witness Bednarcik read the Company's response to Public Staff Data Request

183-3(c)[44] which stated **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[END CONFIDENTIAL] (Id. at 275.)

As to the argument that the Company should have sought guidance from DEQ once it was aware of Zachry's costs, witness Bednarcik testified that cost is outside the purview of DEQ and CAMA contains no cost considerations. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** She contended that the Company would therefore have

[44] Ex. vol. 26, Confidential Public Staff Bednarcik Rebuttal Cross Examination Exhibit 4.

no argument for the project being modified and, even if it did, the only authority was N.C.G.S. § 130A-309.215 Variance Request within CAMA. She stated the Company did not believe it had strong grounds to request a variance because it "believed it could meet the existing deadline through application of the best available technology and without serious hardship. . . ." (Tr. vol. 24, 128-29.)

Witness Bednarcik concluded that the EPC costs paid to Zachry were reasonable and prudent. She stated, "there are major differences in the scope and requirements of the Winyah STAR Facility project and the Buck beneficiation project," and that "These differences explain the difference between the initial estimate provided in the RFI and the actual EPC costs and support the Zachry EPC contract as reasonable." (Id. at 129-30.)

DISCUSSION AND CONCLUSION

Prudence of Cape fear and H.F. Lee Beneficiation Projects Construction Costs

Public Staff Witness Moore recommended the Commission disallow $130,384,392 of the costs to construct the Cape Fear and H.F. Lee beneficiation facilities. In support of his recommendation, witness Moore asserted that, after it learned the estimated cost for Zachry to construct the Cape Fear and H.F. Lee beneficiation projects was well over twice the cost estimated for H&M to construct similar facilities, the Company should have pursued one or more of several feasible alternative courses of action to attempt to mitigate the cost of the project. Based on additional information obtained through discovery after he filed his testimony, witness Moore presented an alternative analysis of the respective costs for H&M

and Zachry to construct facilities with comparable components. Witness Moore's analysis showed that, taking into account the different components contemplated in each cost estimate, the cost for Zachry to construct the facility was still nearly double the cost for H&M to perform the construction.

DEP witness Bednarcik testified that the Company's compliance activities have been reasonable, prudent, and cost-effective, that the Company has processes in place to ensure costs "are not exorbitant, unnecessary, wasteful, or extravagant," and that the Company has properly managed the activities to ensure compliance with appropriate deadlines. She asserted that witness Moore failed to take into account differences in the components of the facilities on which the H&M and Zachry construction cost estimates were based. She further asserted that the STAR beneficiation facility at Winyah was not comparable in components, performance specifications, or costs.

Witness Bednarcik also contested the alternatives witness Moore testified the Company should have pursued when it learned the cost for Zachry to construct the beneficiation facilities would dwarf the other cost estimate for H&M to construct the facilities. In response to witness Moore's testimony that the Company should have sought bids from a larger group of contractors, witness Bednarcik testified that there was no need to solicit additional bids because the companies DEP had sent the original bids to were working on other projects for the Companies or had done so in the past. Despite evidence that H&M had removed itself from consideration due to the large scope of the combined projects, witness Bednarcik dismissed witness Moore's testimony that the Company should have entered into three separate contracts for the construction of one beneficiation project each, and that it could have further divided the construction into separate components. Witness Bednarcik dismissed out of hand witness Moore's testimony that the Company should have sought statutory relief from the General Assembly when it learned of the construction costs, despite the fact that DEC had done so in the context of the REPS standard in N.C.G.S. §62-133.8(i)(2) to seek delays in requirements related to swine and poultry waste set asides. Witness Bednarcik concluded that, because the section of the CAMA Amendment relating to beneficiation did not mention cost, "the General Assembly did not intend for cost to be considered . . . ." Finally, in response to witness Moore's testimony that the Company should have consulted with DEQ regarding possible alternative courses of action to completing the beneficiation projects based on the Zachry contract, witness Bednarcik asserted that DEQ did not have authority over the cost of compliance with environmental regulations and that the Zachry cost estimate was reasonable.

The Commission has engaged in a thorough review of the evidence and finds and concludes that witness Moore addressed witness Bednarcik's criticism of his comparison of the respective H&M and Zachry cost estimates. Witness Moore's credible calculation of the respective costs for H&M and Zachry to construct facilities to meet the requirements set out in the CAMA Amendment demonstrates that the costs for Zachry to construct the Cape Fear and H.F. Lee beneficiation facilities was double the cost for H&M to do so. Given this comparison, and Zachry's overall estimated contract amounts of **[BEGIN**

CONFIDENTIAL] [redacted]

[END CONFIDENTIAL] the Commission does not find persuasive witness Bednarcik's testimony that the Company has taken steps to ensure that the costs it incurred to comply with regulatory obligations were not exorbitant or extravagant.

The Commission further finds and concludes that several of the alternatives recommended by witness Moore, including that the Company should have sought additional bids for the EPC work, that it should have broken the EPC contract into three separate contracts and/or separate components, and that the Company should have sought relief from the General Assembly, were prudent and feasible, especially in consideration of the significant costs.

Based on the entire record, the Commission finds and concludes that the DEBS' decision, as an agent for and on behalf of the Companies, to enter into a contract with Zachry for the construction of three beneficiation facilities, including the Cape Fear and H.F. Lee facilities, at a cost that was double the estimate it had received for H&M to construct comparable facilities, was not reasonable or prudent. The Commission further finds and concludes that, as described by witness Moore, there were several feasible alternative courses of action the Company should have taken to mitigate the staggering cost of the projects before moving forward with the Zachry contract, and that the Company failed to meet its burden of demonstrating the reasonableness and prudence of the beneficiation facility construction costs. Based on the foregoing, the Commission finds and concludes that it is appropriate that the Company bear the costs in the amount of $130,384,392 for its unreasonable and imprudent actions.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 16-18

The evidence supporting these findings of fact and conclusions is found in the Application, Form E-1, and the testimony and exhibits of DEP witness Bednarcik and Public Staff witnesses Garrett and Maness.

Summary of the Evidence

DEP DIRECT TESTIMONY

In her direct testimony, DEP witness Bednarcik testified that DEP is seeking recovery of CCR expenses incurred from September 1, 2017, through June 30, 2019, and costs to be incurred through February 29, 2020, related to what she contended were reasonable, prudent, and cost-effective approaches to comply with applicable regulatory requirements. (Tr. vol. 12, 33.)

Witness Bednarcik testified that, pursuant to CAMA, the Company was required to close the high-priority-designated Sutton site by excavation by August 1, 2019. She further testified that the Company was required to close the high-priority-designated Asheville site by excavation by August 1, 2022. (Id. at 37.)

Witness Bednarcik testified that the Company completed excavation of the 1982 Ash Basin on September 30, 2016. She further testified that, from September 2017 through September 2019, ash was excavated from the 1964 Ash Basin and was transported to Homer, Georgia, where it was disposed of in a landfill owned by Waste Management, Inc. Witness Bednarcik indicated that the DEP was designing a landfill at Asheville Station for the storage of approximately 1.2 million tons of ash from the 1964 Ash Basin. (Id. at 46-47.)

Witness Bednarcik further described the actual and forecasted-site specific work in an exhibit to her testimony,[45] which included an aerial photograph of the Asheville site. The updated excavation plant for Asheville described the 1964 Ash Basin as follows:[46]

> The 1964 Ash Basin Dam (BUNCO-097) was constructed in 1964 to serve as a wastewater treatment facility for the treatment of ash sluice water. The surface area of the basin is approximately 45 acres. The basin does not retain a permanent pool with the exception of a three-acre unlined retention pond known as the "Duck Pond."
>
> Production ash is sluiced to a concrete rim ditch system that is located within the footprint of the 1964 Ash Basin. The rim ditch system also receives plant stormwater drainage and low volume wastewater from the Duck Pond. CCR is dredged from the rim ditch, dewatered, and transported off-site.
>
> The wastewater from the rim ditch process is treated in the rim ditch system and then pumped through the center pond filters (constructed at the end of the rim ditch) to a settling pond outside of the 1964 Ash Basin. The settling pond serves as the monitoring point for Outfall 001 of the Plant's National Pollutant Discharge Elimination System (NPDES) permit (NC0000396). Treated wastewater discharged from this settling pond is routed to the French Broad River in accordance with the terms and conditions of the NPDES permit.

(Id. at 47.) Bednarcik Exhibit 7 states in part, "[t]he tasks that DE Progress has performed and will perform from September 1, 2017 through February 29, 2020 are a continuation of the activities for which costs approved in the prior DE Progress rate case," and "[t]hese activities and associated costs continue to be necessary, appropriate, and consistent with applicable regulatory requirements."

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[45] Ex. vol. 13, Bednarcik Exhibit 7.

[46] Ex. vol. 13, Bednarcik Exhibit 9.

Witness Bednarcik concluded that the closure activities she described were necessary to comply with regulatory obligations, that processes were utilized to ensure costs "are not exorbitant, unnecessary, wasteful, or extravagant," and that the Company had properly managed the activities to ensure compliance with appropriate deadlines. (Tr. vol. 12, 56-58.)

INTERVENOR TESTIMONY

On behalf of the Public Staff, witness Garrett recommended a disallowance, in the amount of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, of costs incurred at the Asheville site for the transportation of ash to the R&B Landfill. (Tr. vol. 15, 1222.)

Witness Garrett testified that, according to the testimony of DEP witness Bednarcik, DEP is seeking recovery of $99,274,167 in costs incurred, during the period from September 1, 2017, through June 30, 2019, for excavation activities at its Asheville Station. Witness Garrett noted that the Company's Asheville Steam Electric Generating Plant Coal Ash Excavation Plan 2018 Update[47] indicated that the Company was evaluating disposal of ash from Asheville Station at the on-site landfill at Rogers Energy Complex (also known as Cliffside Station) and the construction of an on-site landfill at the Asheville site. (Id. at 1252-54.)

Witness Garrett testified that the Company indicated in response to Public Staff data requests that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** was spent for 1,651,500 tons of ash to be excavated from

[47] Ex. vol. 13, Bednarcik Exhibit 9.

Asheville Station and transported to and disposed of at the R&B Landfill between September 1, 2017, and December 31, 2019. (Id. at 1255.) Based on this information provided by the Company, witness Garrett calculated a per ton cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** which he considered excessive. He opined that the costs became excessive primarily as a result of transportation costs of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** associated with the off-site disposal of ash at the R&B Landfill. (Id. at 1256.)

Witness Garrett testified that the Company had lower cost options such as "disposal of the ash at the Rogers Energy Complex, also known as Cliffside, or in an onsite landfill at the Asheville site." (Id. at 1257.) He testified that DEP chose not to utilize the landfill at Cliffside Station. In response to a Public Staff data request asking whether the Company considered disposal at Cliffside, DEP referenced its evaluation of the proposals and included a short-list comparison of the lowest cost options.[48] Based on his review of the information contained in Confidential Garrett Exhibit 12, witness Garrett concluded as follows: **[BEGIN CONFIDENTIAL]**

- [redacted]
- [redacted]

[48] Ex. vol. 15 -Confidential, Confidential Garrett Exhibit 12.

[redacted]

[END CONFIDENTIAL] (Id. at 1258.)

Witness Garrett also testified that DEP chose not to construct an on-site landfill to accommodate ash excavated during the deferral period. However, in response to a Public Staff data request, DEP indicated that it had started the permitting process for an on-site landfill by submitting the Site Suitability Report to DEQ on April 3, 2019, and, that it was issued the Final Permit to Construct, Solid Waste Permit, and Zoning Permit to construct and operate the CCR landfill on February 7, 2020. (Id. at 1259.)

Witness Garrett testified that, while the Commission had previously approved recovery of costs incurred to transport ash from the Asheville site to the R&B Landfill in the Sub 1142 Rate Case proceeding, the approval was "based on the fact that the ash excavated and transported from the 1982 Ash Basin had to be removed to allow for the construction of the combined cycle plant to meet the deadlines required by the Mountain Energy Act." (Id. at 1260.) He asserted that since then there has been a material change in facts regarding the on-site landfill as compared to the record in the Sub 1142 Rate Case. In support of his assertion, he referenced the following testimony from the Sub 1142 Rate Case:

On page 28 of my joint testimony filed with Public Staff witness Vance F. Moore in the E-2, Sub 1142, rate case I stated:

> Upon passage of the MEA in 2015 which extended the closure deadline for the CCR units at the Asheville facility to December 31, 2022, DEP should have pursued an on-site industrial landfill. It does not appear DEP evaluated or identified fatal flaws eliminating the possibility of an on-site industrial landfill. Had an on-site industrial landfill capable of storing three million tons of CCR been pursued, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in hauling costs could potentially be avoided. While the design and construction of an on-site industrial landfill at the Asheville facility would have been technically challenging, it is our opinion that it could be done at a lower cost than hauling the remaining CCR off-site."

On pages 14 through 16 of his rebuttal testimony filed in the E-2, Sub 1142, rate case, DEP witness Kerin stated:

> Potential siting and construction of a CCR landfill within portions of the Asheville 1982 basin and limited portions of the 1964 basin was evaluated as early as 2007 prior to the passage of CAMA. However, earthquake and seismic issues, and its physical proximity to the French Broad River prevented this option.
>
> In summary, while on-site CCR landfills had been researched in the past for Asheville, the Mountain Energy Act of 2015 effectively made construction of a new on-site CCR landfill [ ] technically unfeasible given the short time period to replace the coal-fired generation by 2020, and close both ash basins by 2022.

(Id. at 1260-62.) Witness Garrett testified that witness Kerin's testimony in the Sub 1142 Rate Case proceeding excerpted above implies that it was not possible to construct an on-site landfill at Asheville Station in 2015, and that witness Bednarcik's testimony in the current proceeding that the Company is pursuing an on-site landfill makes transportation costs incurred for off-site disposal unreasonable and provides the Commission with a basis for reviewing the costs. (Id. at 1162.)

On cross-examination, witness Garrett noted that witness Kerin testified in the Sub 1142 Rate Case that there were design issues with an on-site landfill but he "did not provide any report that substantiated those design issues would not be overcome." (Id. at 1405.) When counsel for the Company suggested during cross-examination that the Public Staff was attempting to re-litigate issues related to cost recovery for excavation activities at Asheville Station decided in the Sub 1142 Rate Case, witness Garrett clarified ash at issue in the present rate case is ash hauled from the 1964 Ash Basin, whereas "The last rate case was specific to the ash that was removed from the [1982 Ash Basin] for the construction of the combined cycle plant." (Id. at 1412.)

Witness Garrett testified that, when asked during discovery to explain why the Company was prevented from pursuing an on-site landfill at Asheville Station in 2015 but had since obtained a permit to operate, DEP provided the following explanations:[49]

> a. The landfill which was conceptually sited over portions of the 1982 and 1964 basins was sized to provide 20 years of capacity and was significantly larger than the landfill currently being built on site (5.2 million tons of capacity vs 1.3 million tons). The site of the current landfill was evaluated and considered to be too small to meet the projected capacity needs in the 2007-2011 time period and was thus not further evaluated at that time.

[49] Ex. vol. 15, Garrett Exhibit 13.

> Note that seismic issues were a significant factor in the design of a landfill sited over ash. Such a design required placement of stone columns and a stone mat to support the landfill during a design earthquake. Siting a landfill over natural soils, such as the landfill currently being built, does not face the same seismic risk and is stable under a design seismic event.

(Id. at 1262-63.) He further testified that the response identified siting, design, and schedule issues but ultimately did not provide "compelling evidence" to support DEP's decision to haul ash to the R&B Landfill at a higher cost. He opined that DEP witness Kerin's testimony in the Sub 1142 Rate Case was based on a 2007 evaluation under significantly different design assumptions than in the CAMA, the CCR Rule, and MEA era. (Id. at 1263-64.) He opined that, in order to determine that the transportation costs DEP sought to recover were reasonable and prudent, the Company would need to provide a comprehensive independent analysis of the landfill development options at the Asheville site from the 2014 to 2015 timeframe. (Id. at 1264.)

On cross-examination, witness Garrett clarified that when discussing DEP's failure to evaluate an on-site landfill, he was specifically referring to the conversion of the 1964 Ash Basin to an industrial landfill – not the area used for laydown during the construction of the combined cycle plant which witness Bednarcik designated as Quadrant 1 in the diagram of the site included in her prefiled rebuttal testimony. (Id. at 1409-10.) Witness Garrett referenced N.C.G.S. § 130A-309.214(a)(1)a. which provides that conversion of coal combustion residuals impoundments to industrial landfills is a permissible means of closing high-risk impoundments. (Id. at 1403.)

Witness Garrett was asked a number of questions regarding the following excerpt from the Commission's Order in the Sub 1142 Rate Case proceeding:

> The Commission determines that similar considerations come into play when assessing the prudence of the Company's decision to transport the Asheville plant CCRs off site once CAMA became law. The MEA, while extending the closure deadline to August 1, 2022, required construction of a new combined cycle plant. The new plant must be built on site of one of the Asheville plant's basins. This meant that the basin had to be emptied of coal ash. That along with the need for an extensive construction laydown area necessary to allow efficient construction of the new plant, left no space at the Asheville plant site at which to build an on-site landfill. As witness Kerin put it, the MEA effectively made construction of a new on-site CCR landfill technically infeasible given the short time period to replace the coal-fired generation by 2020 and to close the coal ash basin by 2022.

(Id. at 1414.) Witness Garrett contended the excerpt above referred to the ash that had to be moved from the 1982 Ash Basin to facilitate the construction of the combined cycle plant and that witness Kerin's testimony, which the Commission relied on, did not provide, "any analysis with regards to the ash that's in the 1964 basin" or repurposing that basin as a landfill. (Id. at 1416.) When asked about DEP witness Bednarcik's rebuttal testimony that constructing and utilizing an on-site landfill of any size was not feasible between September 1, 2017, and December 31, 2019, witness Garrett responded that witness Bednarcik was not working in her current role in the 2014 through 2016 timeframe and would not have first-hand knowledge to form such an opinion. He further testified that witness Bednarcik's conclusion that an on-site landfill was not feasible during the timeframe was made without an appropriate evaluation of that option. (Id. at 1419-20.) Witness Garrett was then asked whether he provided any analysis that a landfill could be built at the time, to which he responded:

> I can only speak as far as the feasibility of repurposing the 1964 ash basin based on my own experience doing that exact type of project for another utility Company. I was involved in a project where we developed a very specific sequence of ash excavation in order to open up very small areas within the ash basin, certified them closed, constructed a landfill, and then placed the ash into that landfill in a very specific sequence so that the ash basin could be repurposed.
>
> I think - - it was upon Duke Energy Progress to do that type of evaluation to confirm that they had no other option other than to haul ash to Homer, Georgia.

(Id. at 1419-20.) Witness Garrett testified that the 1964 Ash Basin has a footprint of approximately 46 acres whereas the permitted 1.3 million ton landfill has a footprint of 12.5 acres in the area previously used for the combined cycle construction laydown; therefore, the Asheville site could potentially facilitate another landfill of greater capacity that DEP should have specifically evaluated. (Id. at 1423-24.)

Witness Garrett recommended that the Commission disallow **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of the costs incurred at the Asheville site. This disallowance is calculated by multiplying the total 1,651,500 tons disposed of between September 1, 2017, and December 31, 2019, by the per ton transportation cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** which is the rate DEP paid to transport ash from the Asheville site to the R&B Landfill. (Id. at 1259.)

DEP REBUTTAL TESTIMONY

In her prefiled rebuttal testimony, DEP witness Bednarcik responded to Public Staff witness Garrett's recommendation that the Commission disallow **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for costs the

Company incurred between September 1, 2017, and December 31, 2019, to transport 1,651,500 tons of ash from Asheville to the R&B Landfill in Georgia. (Tr. vol. 17, 102.)

Witness Bednarcik asserted that, in the Company's previous Sub 1142 Rate Case, the Commission had approved costs associated with purchase orders dated October 2015 and November 2016 for the transportation of ash from Asheville to the R&B Landfill. She added that, in approving the costs, the Commission agreed with the Company that alternative options presented by witnesses Garrett and Moore involving the disposal of ash from Asheville Station in an on-site landfill or at Cliffside Station were not the most prudent options. (Id. at 103-04.)

On cross-examination during the live hearing, witness Bednarcik acknowledged that, unlike witness Kerin, whose testimony regarding the Asheville Station excavation the Commission relied upon in the Sub 1142 Rate Case proceeding due to his having "'lived' th[e] project since its inception," she had "not personally been involved with the Asheville project from its beginning." (Id. at 419.)

Witness Bednarcik disagreed with witness Garrett's testimony that there had been a "material change in facts regarding the onsite landfill at Asheville" that warranted consideration of the costs to transport ash to the R&B Landfill in the Company's present rate case. Witness Bednarcik asserted that the only way the Public Staff could demonstrate a material change would be to provide designs, plans, or other evidence showing a three million ton on-site landfill could have been constructed and permitted in time to avoid the commencement of offsite disposal on September 1, 2017. (Id. at 104-05.)

Witness Bednarcik also asserted that the on-site landfill proposed by the Public Staff in the Sub 1142 Rate Case "was, and continues to be, an infeasible option," and that the on-site landfill currently being constructed at Asheville Station "is not the same 3 million ton-capacity landfill that the Public Staff argued should have been pursued in [the Sub 1142 Rate Case]." (Id. at 104; emphasis in original.) She stated, "Due to siting constraints, including wetlands, property buffers, and topography, the maximum capacity of the on-site landfill at Asheville currently being constructed is 1.3 million tons of CCR." (Id. at 105; footnote omitted.)

Witness Bednarcik claimed that the Company's plans to construct an on-site landfill at Asheville Station are not inconsistent with the testimony of DEP witness Kerin in the Sub 1142 Rate Case regarding the feasibility of constructing an on-site landfill at Asheville Station. Witness Bednarcik asserted that Company witness Kerin "never testified or implied that an on-site landfill of any size was infeasible . . ." In support, she cited witness Kerin's testimony during the live hearing in the Sub 1142 Rate Case that "building a landfill of the appropriate size that can handle 3 million tons of ash" was not technically feasible. Witness Bednarcik asserted that "the Company's position that a much larger onsite landfill was impossible to construct in 2015" was not invalidated by "the Company's ability to construct a relatively small on-site landfill at Asheville after 2020 . . . ." (Id. at 106.)

Witness Bednarcik testified that the Public Staff failed to take into account the "real-world application" of CAMA and the MEA in its assessment of the Company's actions, including the Company's need to manage multiple large-scale projects at Asheville Station contemporaneously. She indicated that size and proximity of the Asheville Station property to a lake, interstate, and residential properties restricted closure options at the site. Witness Bednarcik referenced witness Kerin's testimony in the Sub 1142 Rate Case proceeding that the Company considered the site of the landfill currently being designed to be too small to meet the needs projected during the 2007-2011 time period and indicated that it was not given further consideration at that time. (Id. at 107-09.) She went on to argue that it was impossible to construct an on-site landfill of any size at Asheville Station and that, "To rationalize the Public Staff's disallowance, one would have to assume that the Company could have created space out of thin air . . . ." (Id. at 110.)

Witness Bednarcik again referenced witness Kerin's testimony in the Sub 1142 Rate Case proceeding to support her contention that a landfill capable of storing the ash from the 1964 Basin and production ash from the coal-fired unit at Asheville Station was not feasible. She noted that witness Kerin's testimony "was confirmed during the planning and design of the new landfill." (Id. at 110.)

On cross-examination during the expert witness hearing in the current rate case proceeding, witness Bednarcik was asked whether she agreed that witness Kerin's conclusion that an on-site landfill was infeasible was made without the benefit of an analysis performed after CAMA was passed in 2014.[50] In response,

[50] Changes to the status quo caused by the passage of CAMA included the requirement that the Company close the impoundments at Asheville Station by August 1, 2019, the need for additional ash storage capacity for production ash if the plant were to continue to operate, and the ability to convert the land upon which the impoundments were located to a lined landfill.

witness Bednarcik discussed a variety of studies she said the Company relied upon in planning the Asheville Station excavation, but she ultimately acknowledged that those studies predated the passage of CAMA and that they assumed construction of a landfill on top of existing ash in the 1964 and 1982 basins or offsite. (Id. at 421-22.) When asked whether the Company had conducted a new evaluation of closure options at Asheville Station after the passage of the MEA,[51] witness Bednarcik testified, “An evaluation was not done because there was no way we could have - - I would say based upon what I know talking to people at the site, visiting the site while all that work was going on at the same time, we could not have built a base - - a landfill at that site during that time period.” (Id. at 424.) Witness Bednarcik also acknowledged that the Company did not perform an analysis before deciding to construct the on-site landfill currently being designed. She testified:

> [W]hat we relied upon was physically being able to execute work within that basin. And also looking knowing that there were springs, knowing that in order to build a basin in- - - or a landfill inside the basin, you would have to excavate the ash and put it on a lined something or other in order to do that. So again, physically we did not have the space on site while all that activity was going on to do a landfill inside the basin. So a study was not needed to do - - to make that evaluation.

(Id. at 426.)

When asked on cross-examination whether the size of the landfill was based on the Company’s needs as of 2019, witness Bednarcik asserted that the

[51] Changes to the status quo caused by the passage of the MEA included the requirements that the Company close the impoundments at Asheville Station by August 1, 2022, that the Company cease operations of the coal-fired power generating units by January 31, 2020, and that the Company construct a combined cycle plant at the site.

size of the landfill was based on the area available and stated, "that is the biggest landfill that we are able to build." (Id. at 431.) However, when asked whether the Company could have performed a phased excavation in the 1964 Basin, which she acknowledged was approximately 46 acres in size, by excavating ash from one section of the basin and stacking it in another section of the basin, lining the excavated section of the basin, and then moving the ash back into the lined area, witness Bednarcik testified, "we could not do that. . . . For the excavation, the handling of the ash that was being produced at the power plant, and the construction of the cycle, and the laydown area; there was not enough room to do all that. It was physically impossible." Witness Bednarcik did not know whether the Company had considered locating the laydown area and employee parking offsite to free up space for an on-site landfill. (Id. at 428-29.)

In addition to the size of the Asheville Station site, witness Bednarcik asserted, as Company witness Kerin did in his rebuttal testimony filed in the Sub 1142 Rate Case proceeding, that seismic concerns prevented the construction of an on-site landfill within the 1964 and 1982 basins. However, she acknowledged on cross-examination that such concerns related to a plan to construct a landfill on top of existing ash, which would not be the case for any new landfill constructed after the enactment of CAMA and the CCR Rule. (Id. at 430.)

Witness Bednarcik characterized the disallowance of transportation costs recommended by witness Garrett as "punitive and unsupportable." She contended that, even if the Company could have constructed an on-site landfill capable of receiving all of the ash excavated during the period from September 1, 2017, to

December 31, 2019, which she disputed, witness Garrett's disallowance did take into account the cost of constructing an alternative landfill. (Id. at 110-11.) She further contended that disallowance of the present-day transportation costs and future savings associated with the Company's planned 1.3 million ton on-site landfill would be an unfair "double-dipping" because in her opinion "the Company should be allowed to recover its unavoidable offsite disposal costs . . . ." (Id. at 112.)

In response to witness Garrett's argument that disposal of ash from Asheville Station at the Company's Cliffside Station offered a lower-cost option for offsite disposal than disposal at the R&B Landfill, witness Bednarcik testified that, while the Company was able to utilize Cliffside for the disposal of approximately 195,000 tons of ash from the Asheville Station's 1982 Ash Basin, disposal of ash from later excavation phases at Cliffside was not the most prudent option due to the termination costs the Company would have incurred had it breached its contract with Waste Management to transport and dispose of ash at the R&B Landfill. Witness Bednarcik also asserted that not using Cliffside to dispose of ash from Asheville Station avoided traffic impacts to the community around Cliffside and reserved landfill capacity at Cliffside for the disposal of ash from that facility. She further asserted that witness Garrett had failed to consider the impact of the DEC's December 31, 2019 settlement agreement with DEQ (Settlement Agreement), which requires that DEC excavate all of its ash basins at Cliffside. Despite these and other factors that witness Bednarcik asserted would make disposal of ash from Asheville Station at Cliffside Station "challenging," she acknowledged that doing so would not have been impossible and would have required transportation of the ash over a shorter distance than to the R&B Landfill. (Id. at 113-15.)

Witness Bednarcik did not agree with witness Garrett's assertion that Waste Management's per ton charge to transport ash to R&B Landfill was excessive. She contended that witness Garrett erred by failing to take into account the fact that Waste Management performed work at Asheville Station related to water management and rim ditch operations. Although witness Garrett clearly asserted that the Company's decision to transport ash offsite was unreasonable and imprudent, and therefore any associated costs were excessive, witness Bednarcik testified that the transportation costs were part of a competitive bid analysis and that witness Garrett failed to explicitly state why he believed the transportation costs were excessive. (Id. at 116.)

DISCUSSION AND CONCLUSION

Prudence of Asheville Closure Costs

With regard to the transportation costs for ash from Asheville Station to the R&B Landfill specific to the present rate case proceeding, the Commission is persuaded by the arguments made by the Public Staff in support of a disallowance. There is sufficient evidence to show that the Company mismanaged the project, that it failed in its responsibilities to properly evaluate an on-site landfill, and that there were alternatives that were both less costly and potentially feasible.

Regarding the Commission's past decision which was based on the record in the Sub 1142 Rate Case available at the time of its decision, the Commission upholds that the transportation costs for ash from the 1982 Ash Basin at the Asheville Station were reasonably and prudently incurred and approved for recovery in rates. However, the Commission's decision in the Sub 1142 Rate Case does not preclude a different decision regarding similar costs in the present proceeding. The Commission agrees with the Public Staff that there has been a material change in facts due to additional information and clarification provided through testimony and exhibits in the present proceeding. Furthermore, there is a clear distinction between the Asheville Station transportation costs sought for recovery now versus then, the costs at issue are associated with ash excavated from primarily the 1964 Ash Basin while the Sub 1142 Rate Case involved ash from the 1982 Ash Basin. Therefore, the Commission finds it appropriate to consider the reasonableness and prudence of the transportation costs sought for rate recovery.

The Commission finds the testimony of witness Garrett informative and persuasive regarding the significant costs incurred to transport ash from the 1964 Ash Basin to the R&B Landfill. Witness Garrett's testimony demonstrates that as an alternative to transporting the ash to R&B Landfill in Homer, Georgia, DEP could have transported and disposed of ash in its on-site landfill at the Cliffside Station, which would have resulted in lower transportation and disposal costs, or constructed additional on-site landfill capacity earlier at Asheville Station. The Commission is not persuaded by witness Bednarcik's contention that witness

Garrett failed to consider DEC's agreement to excavate all of its ash basins at Cliffside pursuant to its Settlement Agreement with DEQ. The Settlement Agreement was not executed until December 31, 2019, years after DEP made the management decisions regarding Asheville Station being contested in this proceeding.

In the context of the pending rate proceeding, the testimony of witness Kerin in the Sub 1142 Rate Case made a sweeping declaration regarding the infeasibility of a new on-site landfill, which cannot be relied on presently as it is not supported by the greater weight of evidence. While witness Kerin lived the Asheville Station project, the Company's concerns he described, including seismic issues, proximity to the French Broad River, Lake Julian, Interstate 26, and residential communities, and operations of the coal-fired power plant, were not evaluated within the parameters that DEP knew or should have known existed after the enactment of CAMA, the CCR Rule, and MEA. On cross-examination, witness Bednarcik conceded that no new study had been performed after the passing of these transformative regulations. After the enactment of CAMA, the CCR Rule, and MEA and prior to continuing to operate under the contract with Waste Management, for the excavation, transportation, and placement of ash from the Asheville Station to the R&B Landfill, it would have been reasonable and appropriate for DEP to properly evaluate an on-site landfill with a capacity of approximately 3 million tons.

Witness Kerin appears to have been relying on the evaluation, planning, and permitting process during the late-2000s of an over 5 million ton capacity landfill for the purpose of storing 20 years of production ash, which was to be constructed on existing ash within the footprint of the 1982 Ash Basin. Contrary to the assumptions at the foundation of his testimony, CAMA prescribed that owners of high-risk impoundments were to excavate and clean close the impoundments or convert the impoundments into industrial landfills and the Public Staff was recommending a 3 million ton capacity landfill, similar in storage capacity to the recommendation in the present case. The Commission finds DEP's continued reliance on evaluations of designs for landfills capable of holding over 5 million tons of production ash and capping-in-place the existing impoundments, performed before the establishment of the regulatory requirements set forth in CAMA, the CCR Rule, and MEA, was not reasonable.

Witness Garrett's testimony also demonstrates his expertise and experience of actually converting an unlined surface impoundment into an industrial landfill. DEP failed to provide any documentation, such as internal or independent evaluations or studies, to refute the possibility of converting the 1964 Ash Basin into an industrial landfill through a phased approach. The Commission finds unpersuasive the testimony of witness Bednarcik regarding the general challenges of facilitating the conversion of the 1964 Ash Basin into an industrial landfill during the construction of the combined cycle plant in the footprint of the excavated and decommissioned 1982 Ash Basin and continued operations of the coal-fired plant. The 1964 Ash Basin had been delineated into different parts, serving different purposes, and the entirety of which was not supporting active operations and could have been theoretically converted through a phased approach. In addition, the challenges could have been mitigated if DEP leased land for laydown areas and employee parking offsite. This would have freed up space for the new 1.3 million ton capacity landfill and created additional operational feasibility. Witness Bednarcik conceded that she did not know whether offsite laydown areas and employee parking was considered by the Company.

Based on the entire record, the Commission finds and concludes that the Company's management of the 1964 Ash Basin excavation at its Asheville Station was unreasonable and imprudent due to its failure to properly evaluate an on-site landfill under the applicable regulations of the time and its decision to contract with Waste Management resulted in the Company incurring transportation costs. The Commission further finds and concludes that the costs the Company incurred as a result of these acts and omissions were similarly unreasonable and imprudent. The Commission also finds and concludes that the alternatives advocated by the Public Staff were not infeasible and would be less costly than the course of action selected by the Company. Based on the foregoing, the Commission concludes that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** should be disallowed on a system basis for transportation costs at Asheville Station.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 19-28

The evidence supporting these findings of fact are found in the testimony of Public Staff witness Maness, DEP witnesses Doss and Riley, and the entire record in this proceeding.

Public Staff Witness Maness testified that he was presenting the Public Staff's recommendations regarding the deferral and amortization of Duke Energy

Progress, LLC's (DEP or the Company) asset retirement obligation related (ARO-related) and non-ARO-related CCR costs incurred between September 1, 2017 and February 29, 2020 (Deferral Period).

Mr. Maness testified that he was recommending or incorporating adjustments in the following areas:

1. The ratemaking treatment of the costs of DEP's Asset Retirement Obligation (ARO) – related coal ash compliance and cleanup activities;

2. The appropriate classification within the rate base of the regulatory assets associated with the ARO-related coal ash compliance and cleanup; and

3. The amortization period for the Company's proposed deferred non-ARO-related costs.

(Tr. vol. 15, 1544-50.)

Witness Maness testified that with regard to ARO-related CCR costs, the Company proposed to establish a regulatory asset for actual CCR expenditures made during the Deferral Period, and to amortize that regulatory asset over a five-year period beginning with the effective date of the rates approved in this proceeding, while including the unamortized balance in rate base. (Id. at 1550.) He further stated that the Public Staff had made the following adjustments to the Company's proposed revenue requirement associated with ARO-related CCR costs:

1. Adjustments to reach a prudent and reasonable level of coal ash expenditures, as recommended by Public Staff witnesses Vance F. Moore, L. Bernard Garrett, and Jay B. Lucas;

2. Amortization of the prudent and reasonable balance of ARO-related deferred coal ash expenditures over a 25-year period; and

3. Reversal of the Company's inclusion of the unamortized balance of ARO-related coal ash expenditures in rate base; this reversal, in conjunction with the 25-year amortization period, produces an equitable and reasonable sharing of the burden of coal ash expenditures between the Company's ratepayers and its shareholders.

(Id. at 1558-59, 1619-20.)

Witness Maness testified that the CCR costs that DEP is seeking to recover in this case are not "used and useful," and thus carry no requirement or implication that they must be included in rate base. He stated that in North Carolina utility regulation, the term "used and useful" only applies to the public utility's property (including cash working capital, as discussed below, and materials and supplies), not the expenses it incurs in the operation, maintenance, or disposal of that property. He stated that some might claim that since the costs deferred for coal ash clean-up are associated with property that is or once was used and useful, the costs themselves should be considered "used and useful," and therefore should be included in rate base, to the extent they remain unamortized, pursuant to

N.C.G.S. § 62-133(b)(1). However, in his opinion as a regulatory accountant, and in the opinion of Public Staff counsel, this argument is incorrect and is an inappropriate application of the term "used and useful." If, however, there are expenses that were incurred in the past, but for some reason the Commission decides that they can be deferred for recovery in the future, he testified that the Commission can approve a regulatory asset to capture such expenses, and even provide for a return on them due to the deferral of their recovery (by including them in rate base or otherwise providing for carrying costs). Based on advice of counsel, witness Maness indicated that this treatment is within the discretion of the Commission and authorized under N.C.G.S. § 62-133(d), but it does not transform the Commission-created regulatory asset into capitalized property cost, such as the cost of a generating plant. (Id. at 1571-73.)

Witness Maness testified that he believed that the costs should fall into the category of a deferred expense because the Company has itself chosen to request a regulatory accounting and ratemaking method that does not explicitly account for any ARO-related coal ash compliance costs, either in the past or in the future, as the capitalized costs of property, but instead accounts for them as ongoing expenses, with a proposed regulatory asset intended to provide for the recovery of expenses incurred in the past, expenses that but for the Commission's approval of the deferral request, would be immediately written off. (Id. at 1573-74.)

Witness Maness pointed out that in Company witness Doss's Supplemental CCR Testimony, witness Doss stated that Company witness Bednarcik's Supplemental Testimony notes that the Company's CCR activities were classified as AROs, and, as such, would properly be capitalized costs. According to witness Doss, under Financial Accounting Standards Board (FASB) and Federal Energy Regulatory Commission (FERC) guidance, ARO costs are an integral part of the plant asset that gives rise to the ARO, and therefore must be capitalized as part of such asset when the ARO liability is recognized. However, witness Maness pointed out that although witness Doss is correct with regard to the requirements of the FASB's standards (commonly referred to as GAAP) for financial accounting purposes and the guidance set forth in the FERC Uniform System of Accounts (FERC USOA), in the absence of regulatory assets and liabilities recorded due to regulatory commission rate-setting actions, he fails to acknowledge that this Commission has chosen not to set rates on the basis of expenses calculated and recorded pursuant to GAAP and the FERC USOA (which in their default mode are determined on the basis of a complex process of estimating future costs, determining their present value, and depreciating that present value over time, all the while re-estimating and truing up the costs), but instead on the basis of deferring actual costs for ratemaking purposes as they are incurred, and amortizing those actual costs over time. According to witness Maness, witness Doss also fails to acknowledge that this Commission's use of a different ratemaking methodology itself justifies the recording of regulatory expense on the books in a manner that synchronizes the recognition of expenses for GAAP and FERC USOA purposes with this Commission's ratemaking actions. Therefore, for N.C. retail jurisdictional accounting and ratemaking purposes, the fact that the default GAAP and FERC USOA practices require capitalization of an ARO asset is essentially rendered moot. (Id. at 1621-22.)

Witness Maness also testified that the GAAP/FERC ARO asset recorded on the books of the Company is not included in rate base, and the depreciation and accretion expenses related to the ARO are reversed for regulatory purposes and deferred to a regulatory asset that is only proposed by the Company for rate base inclusion as cash is actually spent. He testified that, in fact, the Company's own workpapers submitted in the general rate case to calculate its proposed deferral and amortization amounts pay no attention whatsoever to the recording or reversal of GAAP/FASB ARO assets and expenses; they simply start in the most direct manner possible for determining the expenses to be recognized for ratemaking purposes: with the actual dollars spent. Finally, witness Maness noted that it is interesting, and perhaps important for the Commission's analysis, to note that the deferred costs being proposed for rate base treatment by the Company are not a portion of the ARO asset itself at the time of proposed rate base inclusion, but instead represent a portion of the costs that would have otherwise already been written off to expense absent the Commission's approval of deferral. (Id. at 1622-23.) Both DEP and the Public Staff filed Late-Filed Exhibits with the Commission (DEP Late-Filed Exhibit No. 24, and Public Staff Late-Filed Exhibit No. 4) that illustrate the accounting entries made to record both the creation, depreciation, accretion, and regulatory entries associated with DEP's coal ash AROs.

Witness Maness testified that this approach is thoroughly consistent with the Commission's August 12, 2003 Order in Docket No. E-2, Sub 826, which the

Company used to justify its 2016 petition for deferral of coal ash costs in Docket No. E-2, Sub 1103. In the Sub 826 Order, the Commission directly stated, in ordering subparagraph 2.b:

> That the adoption of SFAS 143 shall have no impact on PEC's [Progress Energy Carolinas'] operating results or return on rate base for North Carolina retail regulatory purposes and that the net effect of the deferral accounting allowed shall be to reset Duke's North Carolina retail rate base, net operating income, and regulatory return on common equity to the same levels as would have existed had SFAS 143 not been implemented.

(Id. at 1623.)

With regard to any assertion that the Company's classification of the unamortized balance of deferred coal ash costs as "working capital" meant that the balance must be included in rate base, witness Maness testified that it did not, because, in his opinion, this classification is just a matter of convenience. He stated that for working capital to qualify as rate base, it should be the investment made in materials and supplies, cash, and other similar items to finance and provide for the Company's present and future operations; in other words, to "do the work" of providing ongoing utility service. The proposed deferred coal ash compliance costs are expenses incurred in the past that the Company proposes to recover in the future; they have nothing to do with the Company's forward-looking obligation to provide utility service. Normally, it does no harm for the Company to group many disparate items under the heading of working capital; however, one should not mistake the inclusion of past coal ash costs in this group for actual evidence that such costs are in fact "working capital" needed to fund future operations. (Id. at 1575-76.)

Witness Maness testified that the late Charles F. Phillips, Jr., Ph.D., former Professor of Economics at Washington and Lee University, described working capital in this manner:

> Working capital – the funds representing necessary investment in materials and supplies, and the cash required to meet current obligations and to maintain minimum bank balances – is included in the rate base so that investors are compensated for capital they have supplied to a utility.

Charles F. Phillips, Jr., The Regulation of Public Utilities, Third Edition (1993), p 348.

Witness Maness stated that it is very important to note that the items of working capital described by Dr. Phillips – materials and supplies, minimum cash balances, and the cash necessary to meet current obligations (which is typically determined for large utilities through the use of a lead-lag study) – are all focused on doing the current and future work of the utility. Working capital is not like deferred CCR costs, which are expenditures made in the past that the Commission, if it approves the Company's amortization expense proposal, would allow the utility recover in the future. Thus, no matter how it is categorized on paper by a utility filing a general rate case, the CCR deferred costs neither enable or facilitate the provision of current or future utility service, and cannot be classified in substance as "working capital" for purposes of inclusion in rate base. (Id. at 1576-77.)

With regard to the classification of ARO-related CCR regulatory assets in rate base before taking into account the Public Staff's removal adjustment, witness Maness recommended that these assets be reclassified from a working capital classification to a separate classification outside of working capital. He stated that this recommendation was based on his opinion that the regulatory assets associated with ARO-related coal ash clean-up, disposal, and remediation activities do not qualify as true working capital. (Id. at 1629.)

Witness Maness noted that the Commission has limited discretion to depart from the ratemaking formula set forth in N.C.G.S. § 62-133(b) and must do so when necessary to achieve “reasonable and just rates” due to extraordinary circumstances. Gen. Stat. § 62-133(d). Deferrals are, therefore, authorized under the umbrella created in N.C.G.S. § 62-133(d) when deferral is necessary to achieve reasonable and just rates. (Id. at 1552-53.)

Witness Maness stated that seeking a deferral is likely appropriate in this case because, without a deferral, DEP would have to write-off significant ARO-related costs and would not be able to recover those in rates. According to witness Maness, the Public Staff evaluated the Company’s request and its actions and, for purposes of this proceeding, does not object to the deferral of a return on the deferred ARO-related coal ash expenditures during the Deferral Period. (Id. at 1557-58.)

Similarly, witness Maness indicated that the Public Staff does not take issue with the Company’s intent to begin amortizing those expenditures on the effective date of rates approved in this proceeding. He stated that amortization typically begins much earlier: either the month of or the month following the incurrence of the costs. According to Public Staff witness Maness, a delay in this case is permissible given “the magnitude and unique nature of these costs.” (Id. at 1576-77.)

While witness Maness testified that the Public Staff agreed with deferring ARO-related coal ash expenditures, he pointed out that it does not agree with the amortization period proposed by the Company or allowing the Company to include the unamortized balance in rate base. The appropriate amortization period, according to Public Staff witness Maness, is 25 years. (Id. at 1627.) He noted that the Public Staff’s choice of amortization period is grounded in its belief that “it is most reasonable and appropriate for [prudently incurred and reasonable coal ash costs] to be shared equitably between ratepayers and the Company’s shareholders.” (Id. at 1627.)

Witness Maness testified that the Public Staff had been guided in its choice of amortization period for these costs in this proceeding by its belief that it is most reasonable and appropriate for coal ash costs, after specific imprudently incurred or otherwise unreasonable amounts have been identified and disallowed for recovery, to be shared equitably between the ratepayers and the Company’s shareholders. (Id. at 1627.) In this case, the Public Staff believes that equitable sharing should amount to DEP’s shareholders being required to bear approximately 50% of the present value of the September 2017 through February 2020 deferred costs (with carrying costs allowed on the costs up to the point that rates have been estimated to go into effect). (Id. at 1627.) The 50% sharing is accomplished by choosing an appropriate amortization period and excluding the unamortized balance from rate base during the amortization period. (Id. at 1627-58.)

As discussed in detail earlier in this Order, witness Maness testified that the Public Staff believes that a 50% sharing percentage is appropriate and reasonable due to the reasons for such set forth by witness Lucas, and because there is a history of approval for sharing of extremely large costs that do not result in any new generation of electricity for customers. He indicated that the Public Staff believes that a five-year amortization period is simply too short an amortization period for costs of the magnitude and nature of these. He further stated that the Public Staff believes that the totality of the circumstances surrounding the ARO-related CCR costs deferred in this proceeding make equitable sharing appropriate and reasonable for purposes of achieving reasonable and just rates, independent of prudence conclusions. (Id. at 1560-61.)

The uncontroverted evidence stating the difference in revenue requirement between DEP's five-year amortization with a return and the Public Staff's initial 27-year amortization (prior to Stipulation on 9.6% ROE) with no return was Doss Spanos Riley Public Staff Cross Examination Exhibit No. 7 prepared by Public Staff witness Maness. The exhibit showed the revenue differentials listed in the table below. (Tr. vol. 17, 71.)

Year	Difference	Cumulative Difference
1	$100.4 million	$100.4 million
2	$94.6 million	$195.0 million
3	$88.9 million	$283.9 million
4	$83.2 million	$367.1 million
5	$77.4 million	$444.6 million.

This cross examination exhibit demonstrates the customer rate impact of those extremely large costs that do not result in any new generation of electricity for customers.

Witness Maness testified that according to advice of Public Staff counsel, the inclusion in rate base of these deferred ARO-related regulatory assets is left to the discretion of the Commission. Pursuant to N.C.G.S. § 62-133(b)(1), the only costs that the Commission is required to include in rate base are (1) 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 . . . ," and (2) in some circumstances, the costs of construction work in progress. He indicated that he was advised by counsel that beyond those requirements, what is and what is not allowed in rate base is within the legal discretion of the Commission to decide, as long as the rates set thereby are fair and reasonable to both the utility and the consumers. He stated that moreover, N.C.G.S. § 62-133(d) requires the Commission to "consider all other material facts of record that will enable it to determine what are reasonable and just rates." Witness Maness testified that the Commission has taken this approach several times in past cases. (Id. at 1566.)

Witness Maness also testified as to the Commission's findings and conclusions in another recent electric general rate case. He testified that in Dominion Energy North Carolina's (DENC) most recent general rate case, Docket No. E-22, Sub 562, the Public Staff recommended an equitable sharing adjustment for CCR costs similar to what it is recommending in this proceeding. On January 23, 2020, the Commission issued its Notice of Decision in that proceeding, ordering that the Company amortize its deferred CCR costs over ten years, with the unamortized balance not being allowed to earn a return during the amortization period. Although the ratepayer share associated with a ten-year amortization is greater than what the Public Staff recommended in that case, the result still appears to reflect a 74%-26% sharing of costs between the ratepayers and the shareholders, respectively. While each case must be decided on its merits, it is noteworthy that the Commission has recognized the denial of a return on coal ash costs is appropriate in given circumstances. (Id. at 1580-81.)

Company witness David L. Doss, Jr., provided testimony about the accounting guidance applicable to the Company embodied in the FASB's GAAP and FERC's USOA, as well as Orders of this Commission. According to witness Doss, the Company evaluated GAAP and FERC guidance in light of the legal obligations imposed upon it by CAMA and the CCR Rule. The Company determined that the coal ash basins it operated at its coal-fired generating facilities needed to be closed as a result of the passage of CAMA and the CCR Rule. The closure obligation triggered ARO accounting requirements. In addition, the

Commission's Order entered in the Company's E-2, Sub 826 Docket has required the ARO accounting impacts to be deferred into regulatory assets.

Witness Doss took issue with several aspects of Public Staff witness Maness's testimony. According to his testimony, he does not agree with witness Maness's characterization of coal ash ARO related costs as expenses. Witness Doss further disagrees with witness Maness's assertion that the Company can choose whether it will defer coal ash ARO-related costs. Lastly, witness Doss testified that he does not agree with witness Maness's argument that coal ash ARO costs are not characteristic of assets recorded as used and useful property. Witness Doss contends that the costs incurred (relating to the deferred depreciation and accretion) are used and useful as those costs are reasonable and prudently incurred and are intended to provide utility service in the present or in the future through achieving their intended purpose: environmental compliance, the retirement of the ash impoundments and the final storage location for the residuals from the generation of electricity. (Tr. vol. 16, 344.)

Company witness Sean Riley provided testimony on two FASB codified GAAP standards applicable to the Company: ASC 980 and ASC 410. According to witness Riley, ASC 980 addresses requirements specific to regulated entities. In so doing, it provides a linkage between costs and revenues that does not exist for non-regulated companies, and also places a primary emphasis on regulatory ratemaking in the determination of appropriate accounting treatment.

According to witness Riley, ASC 410 outlines the accounting practices and requirements related to the creation of an ARO. It requires companies to assess, on an ongoing basis, whether they have a present legal obligation to remove, dispose, or remediate a long-lived capital asset. If such an obligation exists, then ASC 410 requires that the fair value of such obligation be recorded as an ARO and that simultaneously an Asset Retirement Cost be capitalized, both of which are reflected on the Company's balance sheet.

Witness Riley also provided testimony on the way in which CCR removal costs are accounted for in depreciation studies. He opined that it was not general industry practice to include those costs in depreciation studies prior to the EPA's adoption of its CCR Rule.

He further opined that DEP properly followed then-existing GAAP in its treatment of potential costs associated with CCR remediation prior to the passage of the EPA's CCR rule and then appropriately utilized GAAP ARO accounting once the remediation obligations associated with coal ash became known and estimable.

A major difference in this proceeding between the Company and the Public Staff is whether "equitable sharing" of deferred CCR costs, with its interrelated components of removal of the deferred costs from rate base and choice of an appropriate amortization period, should be adopted by the Commission. The Public Staff recommended a 50%-50% sharing between the Company's ratepayers and shareholders based on the reasons that (1) such an approach is within the Commission's discretion under N.C.G.S. § 62-133(d), and (2) its specific recommendation of a 25-year amortization period coupled with exclusion of the deferred costs from rate base (which achieves this specific level of sharing) is appropriate and necessary in order to establish rates that are reasonable and just.

As discussed earlier in this Order, for purposes of this proceeding, the Commission finds that “other material facts of record” justify an equitable sharing of CCR expenditures from the Deferral Period. First, the Commission finds persuasive the rationale set forth by witness Junis in his testimony; namely, that DEP’s coal ash disposal practices have caused environmental contamination for which the Company has some degree of culpability. This finding of culpability for environmental contamination is appropriate under N.C.G.S. § 62-133(d) even in the absence of evidence of specific costs resulting from imprudence that would be disallowed under N.C.G.S. § 62-133(b).

Second, the Commission additionally finds persuasive the following reasons set forth by witness Maness: (1) the sheer size of the Deferral Period costs ($293.1 million on an N.C. retail level, or approximately $177 per customer, per witness Maness (Tr. vol. 15, 1610)); (2) the lack of any benefit from incurrence of these costs in terms of future electric service or improvements in electric service; and (3) the fact that the incurrence of CCR costs was not the result of an economic analysis by the Company that pointed toward a discretionary activity that would be economically advantageous to ratepayers. These reasons are consistent with the Commission’s past decisions that order equitable sharing for large magnitude abandoned plant costs.

The Commission has approved equitable sharing several times in past cases, most often in the cases of nuclear and coal plants abandoned prior to commencing commercial operation. Also, in Docket No. G-5, Sub 327, Public Service Company of North Carolina, Inc. (PSNC) sought recovery of costs incurred for remediating environmental impacts identified at manufactured natural gas plants (MGPs). Before piped natural gas became available in the 1950s, gas was commonly manufactured by a process that involved the heating of coal in a reduced-oxygen environment. The plants in question in this particular proceeding had been constructed from the mid-1800s to the early- 1900s. The MGPs were taken out of service in the 1950s. By-products of the gas manufacturing process included sulfur, hydrogen sulfide, iron cyanide, light oils, tar, water, and coke. These by-products were disposed of consistent with the law applicable at the time but had become the subject of environmental law and regulation. The anticipated remediation costs were estimated to be substantial. The Commission concluded that it was appropriate to allow PSNC to recover its prudently incurred MCP environmental clean-up costs as reasonable operating expenses amortized over a period of years. The Commission did not allow PSNC to earn a return on unamortized balance. The Commission concluded

> that the proper balance between ratepayer and shareholder interests is achieved by amortizing the prudently incurred costs to O&M expenses in general rate cases but denying the Company any recover from ratepayers of the carrying costs on the deferred and the unamortized MGP clean-up cost balances.

MGP Order at 23. The Commission reasoned that its approach to ratemaking treatment (which also included rejecting the utility's proposed annual tracker mechanism) gave PSNC an incentive to minimize clean-up costs and to pursue contributions from third parties where appropriate. Finally, looking ahead and anticipating extensive future cleanup costs for MGP liabilities, the Commission reasoned that an appropriate amortization period could be determined in each future rate case proceeding, depending on the magnitude of the costs incurred.

This specific issue has also come before the North Carolina courts. In 1989 the North Carolina Supreme Court affirmed the Commission's decision that reasonable rates can include an equitable sharing between ratepayers and investors with regard to plant cancellation costs. In *State ex rel. Utils. Comm'n v. Thornburg*, 325 N.C. 463, 385 S.E.2d 451 (1989) (*Thornburg I*), the Attorney General had sought exclusion of all abandonment costs related to the Harris Nuclear Plant. However, the Commission allowed amortization of the abandonment costs, with no return on the unamortized balance. The Court ruled that the Commission was acting within its discretion:

> [T]he Commission's order does not err as a matter of law in authorizing CP&L to continue to recover a portion of the cancellation costs of the abandoned Harris Plant as operating expenses through amortization. The Commission's determination was supported by several findings and conclusions. First, the Commission found that although "[t]his case must of course be decided on the basis of North Carolina statutes" the "majority of courts and commissions that have dealt with this issue have allowed ratemaking treatment of abandonment losses, usually as operating expenses." Second, the Commission concluded "that a liberal interpretation of the operating expense element of ratemaking so as to include the Harris abandonment losses is appropriate herein." Last, the Commission found further support for its conclusion was provided by N.C.G.S. § 62-133(d), which allows the Commission to consider all material facts in the record in determining rates.
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> . . . .
>
> Last, we disagree with the Attorney General's contention "that strong policy considerations support the disallowance of [cancellation] expenses." We note that jurisdictions have generally dealt with the allocation of cancelled plant costs in one of the following three ways:

> (1) recovery of all of the costs from ratepayers, by allowing amortization of the investment plus a return on the unamortized balance;
>
> (2) recovery of all costs from shareholders through a total disallowance of recovery in rates, instead requiring the utility to write off the entire amount in a single year; or
>
> (3) recovery from ratepayers and shareholders through amortization of costs in rates over a period of years, with no return on the unamortized balance.
>
> . . . Strong policy considerations support the Commission and commentators who have concluded that method three is the best of the three alternatives in that it promotes "an equitable sharing of the loss between ratepayers and the utility stockholders."
>
> . . . .
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> On this record, the Commission's continued use of method three is within the Commission's discretion, and this Court will not disturb that decision.

(Id. at 1568-1570).

For purposes of this proceeding, the Commission finds that the “used and useful” distinction is not a meaningful or legal obstacle to equitable sharing, based on the following reasons.

First, the Commission’s authority to order equitable sharing under N.C.G.S. § 62-133(d) overlays the ratemaking cost formula in N.C.G.S. § 62-133(b). In other words, even where property is “used and useful” under N.C.G.S. § 62-133(b)(1), there may be unusual circumstances where denial of a return is appropriate under N.C.G.S. § 62-133(d).

Second, the basis for equitable sharing in the cases of both the costs of abandoned plants and the remediation costs associated with MGPs, turned on the fact that those costs had been deferred to a regulatory asset. The Court in

Thornburg I accepted that the costs (which plainly were incurred for utility plant, albeit not used and useful) could be treated as operating expenses eligible for deferral and recovery through amortization. The change from utility plant to operating expenses, for ratemaking purposes, was effectuated through the deferral of those costs. The same is true for CCR expenditures. Once deferred, they acquire a different character than property used and useful under N.C.G.S. § 62-133(b). Thus, the "used and useful" concept is not applicable.

The Commission agrees with the Public Staff with regard to the classification of deferred CCR costs as working capital. The very title "working capital" strongly implies that it consists of funds and other assets that are expected to be necessary to do the work of providing utility service on an ongoing basis. This interpretation is supported by Dr. Phillips' description, which refers to materials and supplies and cash needed to meet "current obligations." Deferred CCR costs do not fit within this description; they are costs expended in the past, not awaiting expenditure currently or in the future, and thus are not needed to "meet current obligations."

The Commission has reviewed in the present case the "working capital" argument for allowing a return on CCR costs, and rejects that argument both on the basis of witness Maness's testimony as discussed above, and upon further review of the *VEPCO* case.[52]

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[52] The Commission is aware of its different reasoning and outcome in prior rate cases. The issue of equitable sharing is a policy judgment, and with respect to new costs in new rate cases the prior determinations are not adjudicative facts subject to issue preclusion, *stare decisis*, or res judicata. Likewise, the proper interpretation of a case like *VEPCO* is a legal conclusion, and this Commission

The portion of the Court's decision most relevant to the present case reads as follows:

> Like any other business, a public utility must at all times have on hand a reasonable amount of materials and supplies and a reasonable amount of funds for the payment of its expenses of operation. While Chapter 62 of the General Statutes makes no reference to working capital, as such, the utility's own funds reasonably invested in such materials and supplies and its cash funds reasonably so held for payment of operating expenses, as they become payable, fall within the meaning of the term "property used and useful in providing the service," as used in G.S. § 62-133(b)(1), and are a proper addition to the rate base on which the utility must be permitted to earn a fair rate of return.

VEPCO at 414-15, 206 S.E.2d 283, 295-96. The Court thus described "working capital" that qualifies for rate base under N.C.G.S. § 62-133(b)(1) as consisting of either "materials and supplies" or "*cash* funds *reasonably so held* for payment of operating expenses." (emphasis added).

While the Commission has no issue with the Company labeling CCR costs as working capital for its accounting purposes, this does not qualify those costs as "property used and useful" under the *VEPCO* decision. *VEPCO* identified only two types of working capital as entitled to rate base treatment – "materials and supplies" and cash working capital.

Accordingly, based on the record as a whole, the Commission concludes that it is appropriate to treat the Deferral Period CCR costs proposed by the Company for amortization in this proceeding as deferred expenses, not the costs of used and useful property, for ratemaking purposes. This conclusion is supported

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may conclude differently from past decisions. The Commission is not bound by determinations made in past cases on the issue of equitable sharing of CCR costs.

by the testimony of Public Staff witness Maness and the information provided in DEP Late-Filed Exhibit No. 24 and Public Staff Late-Filed Exhibit No. 4. Both Late Filed Exhibits show that the accounting entry made to record the ARO regulatory asset reduces depreciation expense and accretion expense, not any plant in service accounts. Those costs are not “property used and useful,” both because of their nature as operating expenses and also because they were deferred to a regulatory asset. This is legally consistent with the approach taken for the costs of abandoned nuclear construction, abandoned coal plants, and the costs of MGP remediation. The factors cited by the Public Staff in favor of equitable sharing – DEP’s culpability for environmental contamination and the size and nature of costs that do not provide any new electric service or economic benefits to customers, warrant equitable sharing in this case.

In summary, N.C.G.S. § 62-133(b)(1) allows the recovery of a return on investment in property and plant that is used and useful in providing utility service. The Commission takes no issue with the Company’s decision to establish an ARO to recognize its CCR obligations or its labeling of CCR costs as working capital for accounting purposes. However, these accounting practices do not ipso facto transform these costs into expenditures for “property used and useful” under the Act. Further, the Supreme Court’s holding on working capital made in State ex rel. Utilities Commission v. Virginia Electric & Power Co., 285 N.C. 398, 206 S.E.2d 283 (1974) (VEPCO), did not change the used and useful requirement of N.C.G.S. § 62-133(b)(1).

Giving weight to all sections of N.C.G.S. § 62-133 when construing the language of any individual section of the statute, as the North Carolina Supreme Court has indicated the Commission must do, the Commission determines that just and reasonable rates are achieved, based on the evidence in the record in this proceeding, only when the unamortized balance of CCR costs are not allowed to earn a return. *Utilities Comm'n v. Duke Power Co.*, 305 N.C. 1, 18, 287 S.E.2d 786, 796 (1982). Accordingly, based on the record as a whole, the Commission concludes that it is appropriate to treat the CCR costs as deferred operating expenses and not as costs of property used and useful within the meaning and scope of N.C.G.S. § 62-133(b) and to not allow a return on the unamortized balance of the CCR costs.

<u>Prevailing on Sub 1142 Appeal</u>

Public Staff witness Maness testified that in the Company's most recent general rate case (Docket No. E-2, Sub 1142), it proposed to defer and amortize ARO-related coal ash remediation costs incurred between January 2015 and August 2017 over a five-year period, with the unamortized balance included in rate base. The Public Staff recommended instead that the costs, net of certain recommended prudence and reasonableness adjustments, be equitably shared between ratepayers and shareholders, proposing a 26-year amortization with the unamortized balance excluded from rate base, which would result in an approximately 50% sharing between ratepayers and shareholders. Ultimately, the Commission agreed with the Company's position, except that it imposed a $6 million annual penalty on the Company for each of the five years. As a result, in this proceeding the Company has proposed to include in its North Carolina retail cost of service an annualized amount of approximately $41 million in amortization expense related to the Sub 1142 incurred costs, and in its North Carolina retail rate base an annualized end-of period level of unamortized deferred Sub 1142 costs of approximately $142 million, before reduction for accumulated deferred income taxes (ADIT). (Id. at 1586-87.)

Witness Maness testified that several parties have appealed the Commission's Sub 1142 Order to the North Carolina Supreme Court. In particular, the Public Staff appealed the Commission's decisions regarding equitable sharing and the Public Staff's recommended disallowance related to groundwater extraction and treatment. The outcome of the appeals remains pending at the Supreme Court. (Id. at 1587.)

Witness Maness testified that if the Public Staff prevailed on its positions at both the appellate level and on remand to the Commission, not only would it be mandatory for customers' rates effective during the period covered by the Sub 1142 Order to be reduced to match the positions on which the Public Staff prevailed, but it would also only be appropriate for the revenue requirement impact of the Public Staff's successfully appealed Sub 1142 adjustments to be flowed through to the Sub 1142 costs as included in the Sub 1219 case. Also, if the case were remanded and the Commission chose some equitable sharing other than the percentage recommended by the Public Staff, there would still be a need to flow the effect of the remand decision through to the Sub 1142 costs included in the Sub 1219 case. The effect in this case would be to reduce annual Sub 1142 coal ash amortization expense from approximately $41 million to approximately $9 million, and reduce the associated net-of-ADIT Sub 1142 rate base amount from approximately $142 million to $0. The revenue requirement impact in the current case of these changes would be an annual reduction of approximately $41 million. (Id. at 1588.)

Witness Maness testified that the Public Staff had not rolled this adjustment into its recommended revenue requirement in this proceeding, although he stated that it would not be wholly inappropriate to do so, if only to show the Public Staff's position regarding the very costs that are the subject of a pending appellate decision. However, the Public Staff had instead chosen to highlight this issue for the Commission, and recommended that the Commission take whatever steps are necessary to ensure that the outcome of this issue is flowed into each case on which it would have an effect. (Id. at 1589.)

Based on the evidence presented by the Public Staff, the Commission concludes that the rates approved in this case will remain provisional to the extent necessary to reflect the impact of the Supreme Court's decisions on the appeal of Docket No. E-2, Sub 1142, and the Commission's possible decisions on remand of that case.

Right to defer Non-ARO and ARO Coal Ash Costs

Although the Public Staff and the Company have settled the issue of the appropriate and reasonable amortization period for the non-ARO CCR coal ash costs that the Company has presented for ratemaking treatment in this case, the two parties do not agree as to how such costs should be treated for ratemaking purposes in the future. Public Staff witness Maness testified that although the Public Staff agrees that the Company is authorized to defer the capital costs of non-ARO-related coal ash remediation projects it has presented in this proceeding, it was frankly surprised at the number and cost magnitude of these projects. Witness Maness testified that at the time the Company made its Sub 1103 deferral request in late 2016, and until it filed its application in this case, the Public Staff believed that the capital costs mentioned in the Sub 1103 request would be ARO-related, not related instead to projects associated with the continuing operation of the generating plants. He indicated that the ARO was the focus of the petition, and it certainly seemed to be where the highest magnitude risk of loss to the Company resided. (Id. at 1585.)

Witness Maness testified that given the unexpected nature of the non-ARO-related projects proposed for deferral, and the fact that the non-ARO-related deferral requested in this case is more similar in nature to other requests that have been brought forth frequently in the past related to new generation projects than it is to the unique situation presented by the incurrence of ARO-related costs associated with the retirement of its existing coal ash facilities at an extraordinarily high-cost, the Public Staff believes that the automatic right to defer capital costs associated with CAMA or the CCR Rule should not continue. Therefore, the Public Staff recommended that any further authorization to defer CCR-related costs should be restricted to those costs that qualify for the ARO. (Id. at 1585-1586.)

Witness Maness also recommended that the Company be allowed to continue, for regulatory accounting purposes, to defer ARO-related coal ash clean-up, disposal, and remediation costs from March 1, 2020, through the effective end-of-period date in the Company's next general rate case. He noted that the actual amount of costs recovered would be determined by the Commission in a general rate case. He indicated that the basis of his recommendation lay upon the size and unique nature of the costs. He also pointed out that allowing a carrying charge on those costs between rate cases could reduce the Company's incentive to file more frequent general rate cases, though the materiality of the incentive varies based on factors such as the interval between cases, the weighted average cost of capital, and the amount of the deferral. Witness Maness recommended that the Commission consider in the next rate case its allowance of carrying costs between cases when determining whether to include the deferred costs in rate base and the appropriate amortization period. (Id. at 1591-92.)

Based on the evidence provided in this proceeding, the Commission agrees with the Public Staff's recommendation that the Company should be allowed to continue, for regulatory accounting purposes, to defer ARO-related coal ash clean-up, disposal, and remediation costs from March 1, 2020, through the effective end-of-period date in the Company's next general rate case. The Commission will consider the appropriateness of recovery of the costs thereafter in a general rate case. The Commission also agrees with Mr. Maness that with regard to DEP's future general rate cases and periods subsequent to the period considered in this proceeding for non-ARO coal ash costs, the authorization to defer costs should be restricted to those costs that qualify for the ARO. To the Commission's eye, the non-ARO coal ash costs it has deferred in this case appear very similar to other requests that have been brought forth frequently in the past related to new generation projects. It is the Commission's opinion that deferral of those projects should be considered on a case-by-case basis, if proposed by the Company, and not be automatically presumed appropriate for deferral under the Commission's Orders issued in Sub 1103, Sub 1142, or the current proceeding.

Insurance Claims

Public Staff witness Maness also testified that the Public Staff is aware that Duke Energy has filed suit against certain of its insurers to recover coal ash management costs under its policies with those insurers. He indicated that Duke Energy has stated that if it does recover on any of those claims, that recovery will be credited against coal ash management costs to be recovered from its ratepayers. Mr. Maness noted the Public Staff believes that ratepayers should be credited the full amount of any recovery from those policies and that Duke Energy should vigorously prosecute those lawsuits on behalf of ratepayers. (Id. at 1581-82.) The Commission concludes that the Public Staff recommendation is reasonable, and expects the Company to vigorously pursue such litigation on behalf of its ratepayers. DEP should be required to take reasonable and prudent actions to pursue claims for insurance coverage of CCR remediation costs, where justified by DEP's insurance policy coverage. Further, all insurance proceeds received or recovered by DEP from the existing and potential CCR insurance claims should be placed in a regulatory liability account until the Commission enters an order directing DEP as to the appropriate disbursement of the proceeds; the regulatory liability account should accrue a carrying charge at the net-of-tax overall rate of return authorized for DEP in this Order; within ten days of the resolution of any of DEP's CCR insurance claims, whether by settlement, judgment, or otherwise, DEP should file a report with the Commission explaining the result and stating the amount of insurance proceeds to be received or recovered by DEP; and if meritorious concerns are raised by any party or by the Commission regarding the reasonableness of DEP's efforts to obtain an appropriate amount of recovery from the CCR insurance claims, DEP should bear the burden of proving that it exercised reasonable care and made prudent efforts to obtain the maximum recovery from the insurance claims.

ISSUED BY ORDER OF THE COMMISSION.

This the ____ day of __________________, 20_.

NORTH CAROLINA UTILITIES COMMISSION

Kimberley A. Campbell, Chief Clerk