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December 4, 2020

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

RE: Duke Energy Progress LLC's Evidence and Conclusions for Proposed Order Regarding Contested Issues Unresolved by the Public Staff Partial Stipulations
Docket No. E-2, Sub 1219
Docket No. E-2, Sub 1193

Dear Ms. Campbell:

Enclosed for filing in the above-referenced dockets are the public and confidential versions of Duke Energy Progress, LLC's (DEP) Findings of Fact and Evidence and Conclusions for the Proposed Order Regarding Contested Issues Unresolved by the Public Staff Partial Stipulations. These Findings of Fact and Evidence and Conclusions are filed solely on behalf of DEP with the support of the following intervenors for certain portions as noted below:

a. Findings of Fact and Evidence and Conclusions for Findings of Fact Nos. 60-62, filed with the support of Harris Teeter, LLC and the Commercial Group;

b. Findings of Fact and Evidence and Conclusions for Findings of Fact Nos. 63-64, filed with the support of the Carolina Industrial Group for Fair Utility Rates II;

c. Findings of Fact and Evidence and Conclusions for Finding of Fact No.65, filed with the support of the North Carolina Sustainable Energy Association, North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, and Southern Alliance for Clean Energy; and

d. Findings of Fact and Evidence and Conclusions for Finding of Fact No. 66 filed with the support of Vote Solar.

The confidential version is filed on behalf of DEP only. This document contains commercially sensitive information that should be protected from public disclosure. The information designated by DEP as confidential qualifies as "trade secrets" under N.C. Gen. Stat.

§ 66-152(3). If this information were to be publicly disclosed, it would allow competitors, vendors, and other market participants to gain an undue advantage, which may ultimately result in harm and higher cost to customers. Pursuant to N.C.G.S. § 132-1.2, DEP requests that the information marked "Confidential" be protected from public disclosure. DEP is filing all pages designed as confidential under seal and will make the information available to other parties to this docket pursuant to an appropriate nondisclosure.

If you have any questions, please let me know.

Sincerely,

/s/ Camal O. Robinson
Camal O. Robinson

Enclosures

cc: Parties of Record

Need for Rate Increase

59. The Company's request for an increase is driven by its need to keep pace with evolving customer needs and expectations by continuing to make investments that benefit North Carolina and its customers while preserving the Company's financial position and keeping prices as low as reasonably possible.

Harris Teeter Stipulation and Commercial Group Stipulation

60. The Commission finds and concludes that the provisions of the Harris Teeter Stipulation are just and reasonable in light of all the evidence presented and that the Harris Teeter Stipulation should be approved in its entirety.

61. The Commission finds and concludes that the provisions of the Commercial Group Stipulation are just and reasonable in light of all the evidence presented and that the Commercial Group Stipulation should be approved in its entirety.

62. The Commission finds and concludes that the rate design for the SGS-TOU rate schedule should be modified as provided in §§ 3 and 4 of the Harris Teeter and Commercial Group Stipulations.

CIGFUR Stipulation

63. The Commission finds and concludes that the provisions of the CIGFUR Stipulation are just and reasonable in light of all the evidence presented and that the CIGFUR Stipulation should be approved in its entirety.

64. The Commission finds and concludes that unprotected EDIT and deferred revenue should be refunded to customers on a uniform cents per kWh basis as provided in the CIGFUR Stipulation and as illustrated in Pirro Second Settlement Ex. 8.

NCSEA and NCJC et al. Stipulation

65. The Commission finds and concludes that the provisions of the NCSEA and NCJC et al. Stipulation are just and reasonable in light of all the evidence presented and that the NCSEA and NCJC et al. Stipulation should be approved in its entirety.

Vote Solar Stipulation

66. The Commission finds and concludes that the provisions of the Vote Solar Stipulation are just and reasonable in light of all the evidence presented and that the Vote Solar Stipulation should be approved in its entirety.

R-TOUD

67. The Commission finds that reopening Rate Schedule R-TOUD and/or developing another residential time-of-use tariff should be considered in the comprehensive rate design study outlined in the Second Partial Stipulation.

Grid Improvement Plan

68. Deferral Accounting for the eight GIP programs agreed to between DEP and the Public Staff in the Second Partial Stipulation is also supported by separate settlements between DEP and several other intervenors in this docket.

69. When the Commission addresses recovery of deferred costs relating to GIP programs in the Company's next general rate case, the Commission will evaluate the appropriate methodology for allocating GIP costs. The Commission finds and concludes that the Public Staff's recommendation that DEP be required to study the allocation of GIP transmission and distribution investments based on the benefits realized prior to its next general rate case should be rejected.

Fossil Fleet Investments

70. The costs related to the Company's investments in its coal fleet were reasonably and prudently incurred for DEP to meet its obligation to provide safe, adequate, and reliable electric service. There is no credible or substantial evidence disputing the prudency or reasonableness of these costs.

71. It is not necessary or appropriate to impose a limit on the Company's future investments in its coal- or natural gas-fired generating assets.

Nuclear Fleet Investments

72. The costs related to the Company's investments in its nuclear generation fleet were reasonably and prudently incurred.

Depreciation

73. The depreciation rates proposed by DEP in this case, which are based on the Depreciation Study, filed by the Company as Spanos Ex. 1, and previously performed Burns and McDonnell decommissioning studies of each generating site, are just and reasonable, and should be approved in this case.

Recovery of CCR Costs

74. Since its last rate case, DEP has incurred additional costs to comply with federal and state legal requirements relating to its management and storage of coal ash.[1] These requirements mandate the closure of all of the Company's coal ash basins at all of its coal-fired plants in North Carolina and South Carolina. Since its last rate case, DEP has incurred significant costs to continue the closure and compliance efforts that were

[1] Coal ash is also referred to as coal combustion residuals (CCR). The terms "coal ash" and "CCR" are used interchangeably throughout this order.

begun prior to the prior rate case in order to comply with the Company's legal requirements.

75. On a North Carolina retail jurisdiction basis, the coal ash costs DEP has incurred for which it seeks recovery amount to approximately $440.1 million, approximately $404.6 million of which are the actual coal ash basin closure and compliance costs[2] incurred by the Company during the period from September 1, 2017 through February 29, 2020, and the remainder of which are the financing costs incurred by the Company upon these deferred costs through August 2020. DEP is entitled to recover its actual coal ash basin closure and compliance costs. These costs are known and measurable, reasonable and prudent, and used and useful in the provision of electric service to the Company's customers. DEP is also entitled to a return on those costs, at its weighted average cost of capital authorized in this case, during the period those costs have been deferred, through August 2020. Further, DEP proposes that its actual costs, including financing costs, totaling approximately $440.1 million, be amortized over a five-year period, and that it earn a return on the unamortized balance. The five-year amortization period proposed by the Company is appropriate and reasonable and should be approved. The Company is entitled to earn a return on the unamortized balance at its weighted average cost of capital authorized in this case.

Continued Deferral of CCR Compliance Costs

76. DEP further requests authorization to continue deferring CCR environmental compliance costs beginning March 1, 2020, the depreciation and return on CCR compliance investments related to continued plant operations placed in service after February 29, 2020, and a return on both deferred balances at the overall rate of return approved in this case, for cost recovery consideration in a future rate case. The Company's request to continue deferring these costs is reasonable and appropriate and should be approved.

Revenue Requirement

77. The appropriate base revenue requirement is $408,933,000, to be further adjusted by the Public Staff's recommended adjustments to the May 2020 Updates described in Public Staff witness Maness's Supplemental Testimony Supporting the Second Partial Settlement and Exhibits filed on September 16, 2020, and which the Company accepts.[3] In addition, the Company requests that customer rates be offset by a

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[2] The Company's coal ash cost request nets the $404.6 million in actual costs expended against the amount (approximately $5.5 million) the Company had been collecting for coal ash basin closure through depreciation expense, as allowed by the Commission in a previous DEP rate case, Docket No. E-2, Sub 1023. Accordingly, the actual costs expended sought for recovery in this case amount to $399.1 million.

[3] The Company's revenue requirement will be revised to incorporate the impact of the Public Staff's May 2020 Updates adjustments, as discussed further herein, when the Company makes its compliance filing in accordance with this Order.

rate increase of $7,381,000 for the Revised Annual EDIT Rider 1, and a reduction of ($152,348,000) for the Annual EDIT Rider 2 to refund certain tax benefits[4] and ($2,091,000) for the Regulatory Asset and Liability Rider, for a net revenue increase of $261,875,000, as adjusted.[5] This revenue increase is based on the following amounts of test year pro forma operating revenues, operating revenue deductions, and original cost rate base (under present rates), which are to be used as the basis for setting rates in this proceeding: $3,763,735,000 of operating revenues, $3,011,759,000 of operating revenue deductions, and $10,845,429,000 of original cost rate base.[6]

78. The base non-fuel and base fuel revenues approved herein are just and reasonable to the customers of DEP, to DEP, and to all parties in this proceeding, and serve the public interest.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 59

The evidence supporting this finding and conclusions is contained in the Company's verified Application and Form E-1, the testimony and exhibits of DEP witnesses De May, D'Ascendis, Fetter, Hatcher, Newlin and Young, and the entire record in this proceeding.

Need for Rate Increase

Company witness De May testified that the Company's operations have continued to evolve since the Company's last rate case filing in 2017, challenging the Company's ability to continue to provide the type of electric service that customers expect. (Tr. vol. 11, 753.) The expenses driving the need for a base rate increase are investments the Company has made and must continue to make to keep pace with evolving customer needs and expectations. (Id.) He testified that DEP is a well-run company and that customers see and experience the benefits of the Company's efforts every day. (Id. at 774.) However, witness De May testified that the energy sector is in a period of transformation and profound change driven by technological advancements, environmental mandates, storm activity and response, energy security and resiliency efforts, as well as changing customer expectations. (Id. at 753.) Witness De May explained that the Company's Application reflects three general themes that demonstrate

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[4] The EDIT Riders are separately addressed in Findings of Fact Nos. 21-25. Note that the Annual EDIT Rider 2 Year 1 flowback estimate of ($152,348,000) is based on an estimate of the amount to be flowed back to customers through the Company's interim rates and is subject to change based on the actual amount flowed back when the revised rates approved in this Order go into effect.

[5] As adjusted per the Public Staff's May 2020 Updates audit recommendations, which the Company accepts.

[6] As adjusted per the Public Staff's May 2020 Updates audit recommendations, which the Company accepts.

DEP attention to the needs of its customers: 1) improving the customer experience and reliability, 2) moving past coal, and 3) low-income customer support. (Id. at 753-57.)

Witness De May testified that technology is transforming North Carolina and changing the way customers use electricity and interact with their electric supplier. (Id. at 754.) He explained that reliability remains essential as an increasingly connected population continues to expand, especially in the urban areas of North Carolina. (Id.) He explained that today, customers want a new and better experience, driven by information about how they consume energy and by tools to help them manage their consumption. (Id.) Witness De May explained that the Company's Grid Improvement Plan and its deployment of smart meters will continue to improve the customer experience and reliability. (Id.)

Witness Hatcher stated that the Company works each day to make its power system more efficient, more diverse and more reliable. (Id. at 853.) In fact, over the years, DEP has become a leader in efficiency. (Id.) Additionally, the percentage of time the Company's fossil-fueled power plants are available to generate power is at or above the NERC average for comparable units. (Id. at 854.)

Witness De May detailed how the Company is actively working towards achieving a lower carbon future by taking steps to close the final chapters on coal ash and reducing its reliance on coal-fired generation (Id. at 755.) Witness De May provided an overview of investments the Company is making to dispose of coal combustion residuals, including the investments necessary to support ash basin closure activities, in compliance with federal and state regulatory requirements. (Id.) He testified that the Company is investing in natural gas and solar, including the Company's addition of a new combined-cycle natural gas facility at Asheville, and as part of the Company's strategy to reduce its reliance on coal, DEP has taken a fresh look at the viability of several of its coal-fired plants and concluded that making shifts in the expected remaining depreciable lives of some of those assets is a reasonable action to take now. (Id. at 755-56.) In addition, he added that the Company's high performing nuclear fleet has and will continue to provide North Carolina carbon free generation now and into the future. (Id. at 756.) For example, in 2018, DEP's nuclear fleet achieved a 88.58% capacity factor, despite significant challenges attributable to the landfall of hurricane Florence. (Id. at 854.) Witness Hatcher also noted that the Company's achievements have been accomplished while keeping costs low. (Id. at 870.)

In terms of sustainability, witness Hatcher explained that he is proud of what the Company is doing in terms of sustainability goals and how those goals are in alignment with clean and affordable energy as well as protecting the planet and climate action. (Tr. vol. 11, 817-18.) As examples, witness Hatcher stated that since 2005, the Company has reduced its carbon emissions by 39% by the way the Company manages its generation fleet, and is on track to be at 50% carbon reduction by 2030; the Company has invested heavily in solar, with North Carolina having the second largest solar capacity in the country behind California, and plans to invest heavily in battery storage in the future. (Id.at 818.)

Witness De May further outlined how the Company is committed to helping customers who struggle to pay for basic needs with programs and options to assist them during periods of financial hardship. (Id.) He outlined assistance programs the Company offers to help customers reduce their energy costs such as the Company's portfolio of demand-side management and energy efficiency programs, including the Neighborhood Energy Saver Program. (Id.) As a further rate impact mitigation measure, Witness De May testified that the Company has proposed a return on equity of 10.3% instead of the 10.5% that Witness D'Ascendis's analysis supports as the appropriate ROE for the Company. (Id.) In addition, the Company has not requested an increase in the Basic Customer Charge for customers in this case, even though an increase is warranted. (Id. at 756-57.) Witness De May further detailed the Company's commitment to making proactive decreases, such as removing certain executive compensation costs to give customers the benefit of reductions that the Company agreed to in prior rate cases and the Company's proposal to eliminate direct credit card fees for all residential customers who pay their electric bill in this way. (Id. at 757.) Witness De May also outlined additional ideas for low-income energy assistance programs such as: (1) Low-Income Bill Credit on the Basic Customer Charge; (2) voluntary Bill Round-Up program; and (3) Implementation of the Supplemental Security Income Price Discount. (Id. at 757-58.) Witness De May further explained that the Company's commitment to customer assistance expanded through the many settlements reached with intervening parties in this case, including significant contributions of shareholder funds to low-income energy assistance programs – a total of $16 million over the next two years between DEP and DEC – as well as an agreement to explore an on-tariff financing pilot program. (Id. at 798.)

Regarding the Tax Act, witness De May explained that the proposed rates include a reduction from the corporate income tax rate from 35% to 21%. (Id. at 759.) He further noted that the Company included a proposal to return to customers, through a rider, excess federal and state income taxes and deferred revenue resulting from federal tax reform legislation, as well as reductions in the North Carolina corporate income tax rate. (Id.)

Witnesses De May and Young stressed the importance of maintaining a strong financial position for the Company to continue to invest in its infrastructure to make it stronger, smarter, cleaner and more efficient. (Id. at 760.) Company witnesses Newlin and Young testified extensively regarding the capital-intensive nature of the utility industry and their reliance on third-party capital to finance critical infrastructure investments. (Tr. vol. 1, 54; Tr. vol. 3, 39.) Witness Young testified that "Duke Energy generates roughly 5 billion a year in operating cash flow after payment of dividends to its shareholders. This compares to roughly 10 billion a year in capital investments, meaning that we consistently operate on a significantly negative cash flow basis." (Tr. vol. 3, 38-39.) In other words, he explained, "we don't have a stash of money to sit there. We've got – when we've got to do things, we have to go out and borrow that money." (Tr. vol. 3, 47.) Witness De May noted that the single-most determinative factor of a healthy balance sheet and strong financial position is timely recovery of costs and the ability to generate cash flows sufficient to meet obligations as they become due, in all market conditions. (Id. at 864.) Witness De May testified that historically, because of its financial position, the Company has had the financial strength and flexibility necessary to fund its long-term capital requirements, as well as meet short-term liquidity needs, at an economical cost to customers. (Id.) Witness De May further explained that ready access to capital is critical for the Company to continue serving customers. (Id. at 761.) He explained that access to capital is most assured for companies who have strong financial positions, strong investment-grade credit ratings, and adequate cash flow generation to meet obligations as they become due. (Id.) Such financial flexibility, witness De May explained, comes from the ability to access cost-effective capital in all market conditions, which serves the best interest of customers. (Id.)

Witness Newlin explained that maintaining strong credit ratings is important because the Company must compete for third-party capital in the credit markets and that investors "vote with their wallets" and will invest elsewhere if the returns they see from the Company do not meet their requirements or that credit quality will be maintained over the life of their investment. (Tr. vol. 1, 57.) Company witness Fetter further highlighted the significance of strong credit ratings for capital-intensive industries:

> … Duke Progress' credit profile is especially important in view of its need to access substantial amounts of debt and equity, on a near daily basis, to fund its ongoing operations, including capital investments. This includes coal ash remediation activities, along with capital investment related to day-to-day maintenance and infrastructure enhancement related to its ongoing duty to serve customers in a safe and reliable manner. Significantly, a regulated utility is required to raise funding even if the markets are in turmoil and costs are escalating wildly. Strong credit ratings, like those currently held by the Company, limit the negative effects of having to finance at times of great volatility within the capital markets, as was seen back during the 2008-2009 recession when 'BBB'-rated utilities were subject to significantly higher interest rates than 'A'-rated utilities, along with more restricted access, if available at all, along with stricter financing terms.

(Tr. vol. 19, 52.) Financial flexibility, witness De May explained, comes from the ability to access cost-effective capital in all market conditions, which serves the best interest of customers. (Tr. vol. 1, 57.) Witness Young testified that the utility sector was hurt by COVID more so than most other industry sectors and has traded below the S&P 500 since COVID by 15%. (Tr. vol. 3, 45.) Further, witness D'Ascendis testified that the markets are expected to remain volatile through at least the end of 2021. (Tr. vol. 2, 44). The Company presented evidence that strong credit ratings provide more flexibility for DEP to time when it goes to the market for financing and its financial strength has afforded it the ability to stay out of the market when financing terms are unfavorable. Witness Young testified that "we were able to ride through COVID entirely because our strong credit ratings allowed us to ride through with other sources of short-term capital. As the ratings drop, your access to commercial paper, the lifeblood of daily investments, shrink significantly." (Tr. vol. 3, 55.) "And that is part of the reason why our rates are low, is we've been able to access efficiently and effectively across our portfolio and to utilize our resources in this fashion to get the lowest cost debt," he explained. (Id.) Witness Newlin testified that:

> … during the COVID crisis. The Commercial paper markets, especially from A2/P2 issues like Duke Energy, widened greatly. And for some tenor of securities it wasn't available. Overnight was available, but a lot of times a 30- to 40- day type of borrowing in commercial paper was not available during March. And so that market can be somewhat fickle. Now, within the credit facility from the banks, which we use as a backup for commercial paper, it's more expensive, but it will be, you know, based on a draw based on a LIBOR or underlying floating rate of interest, and that amount also expanded greatly. So the cost of capital can be pretty expensive during times of dislocations.

(Tr. vol. 1, 105-06.) Furthermore, in the event the Company does have to access the market during periods of volatility, the Company emphasized the fact that strong credit ratings provide the Company with greater likelihood of access to the capital markets on reasonable terms.

Discussion and Conclusion

As witness De May testified, within this period of transformation and profound change facing the electric sector, the Company's most important objective is to continue providing safe, reliable, affordable, and increasingly clean electricity to its customers with high quality customer service, both today and in the future. (Id. at 762.) The Commission agrees with witness De May's conclusion that the Company's Application is made to support investments that benefit North Carolina and its customers while preserving the Company's financial position all while keeping prices as low as reasonably possible. (Id.) Accordingly, the Commission finds that the Company has sufficiently demonstrated its need for a rate increase.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 60-62

The evidence supporting these findings and conclusions is contained in the Company's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Pirro and Huber, Public Staff witness Floyd, Commercial Group witness Chriss, and Harris Teeter witness Bieber; the Second Partial Stipulation; the Harris Teeter Stipulation; the Commercial Group Stipulation; and the entire record in this proceeding.

As discussed above, the Company entered into settlements with Harris Teeter and the Commercial Group. The Harris Teeter and Commercial Group Stipulations resolve a number of issues between DEP and these parties, including ROE, capital structure, and certain items relating to GIP and rate design. Based on all the evidence in the record, the Commission finds and concludes that the provisions of the Company's settlement agreements with Harris Teeter and the Commercial Group are just and reasonable and that each of these settlements should be approved in its entirety. The Commission addresses the substantive provisions of the Harris Teeter and Commercial Group Stipulations in more detail below.

ROE and Capital Structure

As discussed in the Evidence and Conclusions for Findings of Fact Nos. 26-32, as part of the Harris Teeter and Commercial Group Stipulations, DEP initially agreed that the revenues to be approved in this proceeding should be adjusted to provide the Company, through sound management, the opportunity to earn an ROE of 9.75% and that this ROE will be applied to the common equity component of the ratemaking capital structure consisting of 52% equity and 48% long-term debt. (Harris Teeter Stipulation, § 5; Commercial Group Stipulation, § 5.) Subsequently, DEP and the Public Staff entered into the Second Partial Stipulation which, among other things, stipulated to an ROE of 9.6%. The parties to the Harris Teeter and Commercial Group Stipulations amended their respective agreements to recognize that if the Commission issues an order approving an ROE of 9.6%, the parties to the Harris Teeter and Commercial Group Stipulations agree that the provisions of their respective agreements regarding ROE have been met. As discussed in the Evidence and Conclusions for Findings of Fact Nos. 26-32, the Commission finds 9.6% to be a reasonable ROE for DEP and finds 52% equity and 48% debt to be a reasonable capital structure for DEP in this general rate case.

Grid Improvement Plan

As discussed in the Evidence and Conclusions for Findings of Fact Nos. 33-35 and 66, as part of its settlement agreement with DEP, Harris Teeter supports the approval of DEP's requested GIP deferral with certain conditions detailed therein, including a reservation of Harris Teeter's right to take any position as to the reasonableness of specific GIP costs in a future rate case. (*See* Harris Teeter Stipulation, § 1.) The Commercial Group does not oppose nor specifically support the approval of the Company's requested GIP deferral. (Commercial Group Stipulation, § 1.) As discussed in the Evidence and Conclusions for Findings of Fact Nos. 33-35 and 66, the Commission finds the GIP related provisions of the settlements between the Company and the Public Staff and the other intervenors supporting or not opposing GIP implementation are reasonable and appropriate.

SGS-TOU

DEP witness Pirro explained that the medium general service rate class includes all nonresidential customers with demand requirements from 30 kW to 1,000 kW. (Tr. vol. 11, 1096.) Tariffs within this class include the following rate schedules: Medium General Service (MGS), Small General Service Time-of-Use (SGS-TOU), General Service-Thermal Energy Storage (GS-TES), Agricultural Post-Harvest Service (APH-TES), Church Time-of-Use (CH-TOUE), and Church and School Service (CSE and CSG). (*See* id. at 1087, 1096; *see also*, Pirro Ex. 1, at 1.)

The Company's current SGS-TOU rate schedule consists of a basic customer charge, summer and winter on-peak demand charges, an off-peak excess demand charge, and on-peak and off-peak energy charges. (*See* Tr. vol. 15, 230.) In his direct testimony, witness Pirro described the Company's proposed rate design for the SGS-TOU schedule. (Tr. vol. 11, 1097.) He noted that the customer charge is unchanged at $35.50, which is consistent with the current design to reflect the MGS basic customer charge of $28.50 plus the $7.00 rate applicable to three-phase service. (Id.) He indicated that because marginal cost continues to support the current seasonal and TOU price relationships, the Company is not proposing any structural changes. (Id.) The summer on-peak demand rate continues to exceed the non-summer rate by 19% during the months of June through September, while the on-peak energy rate continues to exceed the off-peak energy rate by 23.4% to incent load shifting to off-peak hours. (Id.) Witness Pirro testified that the Company proposes to increase SGS-TOU rates by 10% more than the increase to Schedule MGS to better match the cost of serving these customers. (Id.) The on-peak and off-peak kWh energy and demand rates are adjusted by the same percentage to recover the requested revenue requirement. (Id.) The off-peak excess kW charge is increased to reflect the MGS distribution-related unit cost to better ensure that customers using electricity primarily during off-peak hours pay the cost of distribution facilities necessary to deliver electricity to the customer. (Id.)

Harris Teeter witness Bieber testified that the rate design for SGS-TOU significantly understates demand-related charges while overstating the energy charges relative to the underlying cost components. (Tr. vol. 15, 228, 232.) He indicated that the proposed on-peak energy charge is 85% greater than the embedded unit cost for the SGS-TOU schedule while the proposed off-peak energy charge is 50% greater than the unit cost. (Id. at 232.) At the same time, the proposed summer on-peak demand charge is only 64% of the embedded unit cost, while the non-summer on-peak demand charge is just 54% of the embedded unit cost. (Id.) Witness Bieber recommended modifications to the proposed SGS-TOU rate design that he believes will improve the alignment between the rate component and the underlying costs while employing the principle of gradualism and mitigating intra-class rate impacts. (Id. at 229.) Specifically, he recommended that the SGS-TOU summer and non-summer on-peak demand charges should be increased by the amount necessary to recover the final SGS-TOU revenue target while maintaining the current on-peak and off-peak energy rates. (Id. at 236.) To the extent the Commission determines that a more gradual movement toward aligning rates with the underlying costs is appropriate, he provided an alternative recommendation: SGS-TOU on-peak and off-peak energy charges should be increased by a percentage that is no greater than half of the approved overall increase percentage for the SGS-TOU revenue target; and the summer and non-summer demand charges can be increased by an equal percentage amount necessary to recover the remainder of the approved revenue target. (Id. at 238.)

Commercial Group witness Chriss also expressed concern that the Company's proposed SGS-TOU rate design does not reflect the underlying cost to serve and as a result shifts cost responsibility within the rate classes. (Tr. vol. 14, 98-101.) He testified that the Commercial Group does not oppose the Company's proposed customer charge for SGS-TOU, the increase to the off-peak excess demand charge, the proposal to maintain time-of-use and seasonal relationships between on-peak and off-peak energy charges, or the proposal to maintain the seasonal relationship between the on-peak demand charges. (Id. at 102.) However, he recommended that the Commission should require any remaining increase to the SGS-TOU subclass to be allocated only to on-peak demand charges in a manner that maintains the seasonal relationship between those charges. (Id.) Witness Chriss also expressed concern over the reliability of SGS-TOU sales data DEP relied upon in making a percentage base rate increase recommendation for the rate schedule. (Id. at 93-97.) As a result, witness Chriss recommended that the percentage base rate increase for each of the medium general service subclasses (i.e., MGS, SGS-TOU, GS-TES, APH-TES, CH-TOUE, CSG, and CSE) should equal the overall increase for the medium general service class. (*See* id. at 97.)

In its settlements with Harris Teeter and the Commercial Group, consistent with witness Bieber's alternative recommendation of a more gradual movement toward aligning rates with the underlying costs, DEP agreed that (1) the SGS-TOU on-peak and off-peak energy charges shall be increased by a percentage amount that is equal to half of the overall percentage increase for the SGS-TOU rate schedule; and (2) the demand charges for the SGS-TOU rate schedule shall be adjusted by the amount necessary to recover the final SGS-TOU revenue target. (Harris Teeter Stipulation, § 3; Commercial Group Stipulation, § 3.) The Harris Teeter and Commercial Group Stipulations also provide that the percentage base rate increase for Schedule SGS-TOU and Schedule MGS shall be the same, with the caveat that DEP shall have the right to adjust the rates for the CSE and CSG rate schedules more than the percentage base rate increase for Schedule MGS as may be necessary to address the Public Staff's concerns. (Harris Teeter Stipulation, § 4; Commercial Group Stipulation, § 4.)

In his second supplemental testimony, Public Staff witness Floyd testified that the Public Staff does not agree with all of the rate design terms of the Harris Teeter and Commercial Group settlements at this time. (*See* Tr. vol. 15, 1005-06.) In his opinion, it would be premature to begin redesigning rates and the terms of service under specific rate schedules, without having a full understanding of the rationale for the change and the impact on other rate schedules and revenues. (Id. at 1006.) According to witness Floyd, making discrete changes to individual rate schedules constrains the ability to conduct a comprehensive study of rates and rate design in the future. (Id.)

In his supplemental rebuttal testimony, filed jointly with witness Huber, witness Pirro testified that he does not believe that the rate design changes proposed in Sections 3 and 4 of the Harris Teeter and Commercial Group Stipulations would constrain the ability to conduct a future rate design study. (Tr. vol. 11, 1165.) He emphasized that these provisions apply only to the SGS-TOU rates proposed in this rate case, and the Company views the comprehensive rate design study an opportunity to reexamine all of its existing tariffs with a fresh eye. (Id. at 1165-66.) Witness Pirro also explained why he thinks that the changes to the SGS-TOU rate design agreed upon in the Harris Teeter and Stipulations are reasonable. (Id. at 1166.) He reiterated that the Company uses the cost of service information as a major component for rate design. (Id.) The Company's unit cost study indicates that the demand charges for SGS-TOU should be $18.15 per kW and energy charges should be 3.835 cents per kWh. (Id.) Current rates on Schedule SGS-TOU are $11.28 per kW and 5.905 cents per kWh for on-peak usage and 4.643 cents per kWh for off-peak usage. (Id.) He concluded that, based on cost causation, the changes to the SGS-TOU rate design agreed to in the settlements with Harris Teeter and the Commercial Group in this rate case are reasonable. (Id.)

During the evidentiary hearing, witness Pirro confirmed that under the Harris Teeter and Commercial Group Stipulations, the energy charges would still be increased, but would simply be limited to half the overall percentage increase the overall SGS-TOU rate is allocated. (*See* id. at 1311.) He agreed that this would be a "small gradual move toward cost" that would help reduce subsidies. (Id. at 1311-12.) He acknowledged that the rate design provisions of the Second Partial Stipulation with the Public Staff also encompass a gradual approach to move rate classes toward parity. (*See* id. at 1312.) He agreed that neither the modest move toward cost agreed to in the Harris Teeter and Commercial Group Stipulations, nor the rate design provisions designed to mitigate subsidies and move toward parity in the Second Partial Stipulation would hinder the Company's ability to conduct a comprehensive rate design study:

> The rates that the Company are proposing in this case are just for this case only until the Company files another rate case. You know, the Company considers this comprehensive rate study as a clean slate to look at not only current rate offerings and, you know, the intricacies within the schedules but also at new product offerings.

(Id. at 1313.) Company witness Huber also agreed that the Company views the rate design study as a "blank slate." (Id. at 1241-42.)

During the DEC hearing, witness Floyd testified, in essence, that he wanted to be cautious about making changes to rate schedules now that might impact a future study of rate design, but did not substantively disagree per se with the changes to OPT-VSS that DEC agreed to in its settlements with Harris Teeter and the Commercial Group. (*See, e.g.,* Tr. vol. 15, 1025-26, 1028, 1078-80.) When witness Floyd was then asked by counsel for the Commercial Group whether he takes a similar position with respect to the SGS-TOU rate design changes proposed in the DEP Commercial Group settlement, witness Floyd confirmed and noted that while he still wants to take a cautious approach to the comprehensive rate study:

> As these days have progressed and the testimony delivered before the Commission in these hearings, taking the Commercial Group and the Harris Teeter settlements in terms of the SGS-TOU for Progress, the Public Staff is optimistic that, based on the Company's testimony, that none of these conditions are going to constrain a future rate study. The Public Staff is receptive to that testimony and would be willing to, at some point, concede a little bit on the cautiousness of my earlier stance. I think it was Mr. Pirro that said, you know, that the study, they perceive this as a blank slate. And that's acceptable to the Public Staff. That really is what we were hoping to get out of such a comprehensive study. In terms of the particulars of the settlements in terms of the on- and off-peak rates, I think it was Mr. Pirro who also testified that the values assigned to those rates would be more cost-based in nature than simply making an across-the-board percentage

change as a result of the case. And the Public Staff supports that. So my cautiousness is a little more tempered in this case.

(Id. at 1125-27.)

The Commission observes that the rate design provisions outlined in Sections 3 and 4 of the Harris Teeter and Commercial Group Stipulations apply only to the SGS-TOU rates proposed in *this* rate case. These provisions do not bind the Company to any particular rate design structure in a future rate case and do not limit the Company's ability to study alternative rate designs. The Commission gives weight to testimony from witnesses Huber and Pirro to the effect that the Company views the comprehensive rate design study as a "blank slate." In addition to evaluating new and innovative rate designs and exploring the topics discussed in the direct testimony of witness Floyd as well as witness Huber, it is clear from the evidence presented that DEP plans to use the study as an opportunity to review and reevaluate all of its existing tariffs, to include SGS-TOU. Moreover, testimony from witnesses Pirro, Bieber, and Chriss indicates that the changes to the SGS-TOU rate design agreed to in the settlements with Harris Teeter and the Commercial Group in this rate case are reasonable and based on cost causation. Further, witness Floyd acknowledged that he is not substantively opposed to these modifications and is "optimistic," based on the Company's testimony, that these provisions will not constrain the comprehensive rate design study. Accordingly, the Commission finds and concludes that the rate design for the SGS-TOU rate schedule should be modified as DEP has agreed in Sections 3 and 4 of the Harris Teeter Stipulation and Sections 3 and 4 of the Commercial Group Stipulation.

GIP Costs Allocated to SGS-TOU Customers

In its settlement agreements with Harris Teeter and the Commercial Group, DEP agreed that any GIP costs allocated to SGS-TOU customers shall be recovered by SGS-TOU demand charges. (Harris Teeter Stipulation, § 2; Commercial Group Stipulation, § 2.) This provision pertains to a certain methodology the Company agrees to propose in the future. The Commission will address recovery of deferred costs relating to GIP programs in the Company's next general rate case, and in that future rate case, the Commission will evaluate whether the Company's proposed allocation methodology is the appropriate way to allocate GIP costs both among customer classes, as well as within each individual rate schedule. Of course, the various parties are free to intervene and advocate the positions they believe are appropriate in the next rate case. Accordingly, the Commission finds and concludes that this provision is just and reasonable as part of its overall approval of the Harris Teeter and Commercial Group Stipulations.

Discussion and Conclusions

As with the Second Partial Stipulation, because the Harris Teeter Stipulation and the Commercial Group Stipulation have not been adopted by all of the parties to this docket, the Commission's determination of whether to accept or reject these settlement agreements is governed by the standards set forth by the North Carolina Supreme Court in *CUCA I* and *CUCA II*.

The Commission finds and concludes that the Harris Teeter Stipulation is the product of the give-and-take between Harris Teeter and the Company during their settlement negotiations in an effort to appropriately balance the parties' positions. In addition, the Commission finds and concludes that the Harris Teeter Stipulation was entered into by DEP and Harris Teeter after discovery and negotiations, and that it represents a proposed negotiated resolution of the matters in dispute between the Company and Harris Teeter in this docket.

Likewise, the Commission finds and concludes that the Commercial Group Stipulation is the product of the give-and-take between the Commercial Group and the Company during their settlement negotiations in an effort to appropriately balance the parties' positions. In addition, the Commission finds and concludes that the Commercial Group Stipulation was entered into by DEP and the Commercial Group after discovery and negotiations, and that it represents a proposed negotiated resolution of the matters in dispute between the Company and the Commercial Group in this docket.

As a result, the Harris Teeter and Commercial Group Stipulations are material evidence to be given appropriate weight in this proceeding. The Commission also gives significant weight to the testimony of DEP witnesses Pirro and Huber regarding the Company's support for the Harris Teeter and Commercial Group Stipulations. Accordingly, the Commission finds and concludes that the Harris Teeter and Commercial Group Stipulations are fair, reasonable, and in the public interest and each settlement should be approved in its entirety.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 63-64

The evidence supporting these findings of fact and conclusions are contained in the Company's verified Application and Form E-1; the testimony and exhibits of DEP witnesses Hager and Pirro and CIGFUR witness Phillips; the Second Partial Stipulation; the CIGFUR Stipulation; and the entire record in this proceeding.

As discussed above, the Company entered into a settlement agreement with CIGFUR which resolves a number of issues between the parties, including ROE and capital structure, as well as certain issues relating to GIP, cost allocation, and rate design. Based on all the evidence in the record, the Commission finds and concludes that the provisions of the CIGFUR Stipulation are just and reasonable and that the CIGFUR Stipulation should be approved in its entirety. The Commission addresses the substantive provisions, and in particular the terms of the CIGFUR Stipulation relating to rate design and cost allocation challenged by the Public Staff, in more detail below.

ROE and Capital Structure

As discussed in the Evidence and Conclusions for Findings of Fact Nos. 26-32, as part of the CIGFUR Stipulation, DEP initially agreed that the revenues to be approved in this proceeding should be adjusted to provide the Company, through sound management, the opportunity to earn an ROE of 9.75% and that this ROE will be applied to the common equity component of the ratemaking capital structure consisting of 52% equity and 48%

long-term debt. (CIGFUR Stipulation, § II.) Subsequently, DEP and the Public Staff entered into the Second Partial Stipulation which, among other things, stipulated to an ROE of 9.6%. CIGFUR and DEP amended the CIGFUR Stipulation to recognize that if the Commission issues an order approving an ROE of 9.6%, the parties agree that the provisions of their agreement regarding ROE have been met. As discussed in the Evidence and Conclusions for Findings of Fact Nos. 26-32, the Commission finds 9.6% to be a reasonable ROE for DEP and finds 52% equity and 48% debt to be a reasonable capital structure for DEP in this general rate case.

Grid Improvement Plan

As discussed in the Evidence and Conclusions for Findings of Fact Nos. 33-35 and 66, as part of its settlement agreement with DEP, CIGFUR supports the approval of DEP's requested GIP deferral with certain conditions detailed therein, including a reservation of its right to review and object to the reasonableness of specific GIP costs in a future rate case. (*See* CIGFUR Stipulation, § III.) As discussed in the Evidence and Conclusions for Findings of Fact Nos. 33-35 and 66, the Commission finds the GIP-related provisions of the settlements between the Company and the Public Staff and the other intervenors supporting or not opposing GIP implementation are reasonable and appropriate.

Rate Design for EDIT Rider

In § IV of the CIGFUR Stipulation, DEP and CIGFUR agree that the unprotected EDIT and deferred revenue giveback to be provided through the EDIT Rider should be refunded to customers on a uniform cents per kWh basis.

In his direct testimony, Company witness Pirro testified that over a lengthy period, residential customers have been subsidized by other customer classes. (Tr. vol. 11, 1091; *see also* Pirro Ex. 5.) This historical subsidy has, in the past, been beyond the range of reasonableness, which he defines as class rates of return within 10% of the total Company rate of return. (Id.) The updated comparison through the test period year now shows significant convergence of the class rate of return over all classes towards the band of reasonableness in accordance with the Company's strategy of gradually reducing the subsidy/excess by 25%. (Id.) Witness Pirro concluded that continuation of this trend would be encouraging and desirable and noted that the Company remains committed to monitoring subsidy/excess levels and making improvements to ensure its rates are fair across the classes of customers served. (Id. at 1091-92.)

Also in his direct testimony, Company witness Pirro described how the Company initially proposed to spread the EDIT Rider among customer classes. (Id. at 1112.) He explained that the rate case revenue requirement relating to EDIT was allocated to each rate class using the factors appropriate for accumulated deferred income tax. (Id.) The rate class revenue requirement was then divided by test year retail billed sales to establish the Year 1 credit rate. (Id.) He indicated that the derivation of the credit rate applicable to each rate class was provided in Pirro Exhibit 8. (Id.)

In his second settlement testimony, witness Pirro provided updates to Pirro Exhibits 4 and 8 to reflect the Public Staff Partial Stipulations and the CIGFUR Stipulation. (Id. at 1146.) As a result of the Company's First Partial Stipulation with the Public Staff, the Company agreed to return protected federal EDIT to customers through base rates instead of the EDIT Rider. (Id. at 1147.) In addition, in the Second Partial Stipulation, the Company and the Public Staff agreed that all unprotected federal EDIT should be returned to customers over a five-year amortization period and that North Carolina EDIT and deferred revenues related to the provisional overcollection of federal income taxes should be returned to customers over a two-year amortization period. (Id. at 1147-48.) Under the CIGFUR Stipulation, the Company agreed to refund unprotected EDIT and deferred revenues to customers on a uniform cents per kWh basis. (Id. at 1148.) Pirro Second Settlement Exhibit 8 recalculates the proposed EDIT Rider rate credits to reflect these provisions of the First Partial Stipulation, Second Partial Stipulation, and CIGFUR Stipulation. (Id.)

In his second supplemental testimony, Public Staff witness Floyd explained that the Company and the Public Staff agreed to use a levelized rider to return EDIT, i.e., a rider that would be at the same level each year. (Tr. vol. 15, 1002.) In the CIGFUR Stipulation, DEP agreed to return EDIT to customers on a uniform cents per kWh basis, i.e., through a rider wherein each customer would receive the same credit amount per kWh. (Id.) Witness Floyd argued that the method agreed upon in the CIGFUR Stipulation would benefit non-residential customers, whereas the method he has used to distribute the EDIT credit returns the monies to customer classes based on amounts each class paid. (Id.)

In the supplemental rebuttal testimony he filed jointly with DEP witness Huber, witness Pirro reiterated that the residential class has historically been subsidized by non-residential rate classes and noted that returning federal unprotected EDIT and deferred revenues on a uniform cents per kWh basis helps balance out this subsidy. (Tr. vol. 11, 1164.) In addition, the uniform cents per kWh flowback is consistent with how rates were designed for the North Carolina EDIT rider that the Commission approved in DEP's last rate case.[7] (Id.)

During the evidentiary hearing, in response to cross-examination from the Public Staff, witness Pirro confirmed that in his original calculation of the EDIT Rider, the Company developed class-specific EDIT credit rates that returned the excess deferred taxes to each class in proportion to how much each class had paid. (Tr. vol. 11, 1197-98.) He acknowledged that under the CIGFUR Stipulation, certain non-residential customers would receive more of an EDIT credit than they had paid, but pointed out that in terms of base rates, "residential customers have been and continue to be subsidized by non-residential customers. And this was a way to sort of balance that. You know, rate design is sort of an art, and you try to be fair, just, and reasonable and find balances, so this was just a way of trying to balance that…and not have further subsidies just continue."

[7] *See* "Derivation of Rider EDIT-1 Decremental Rate," DEP Compliance Exhibit No. 6, Docket No. E-2, Sub 1142 (March 2, 2018).

(*See* id. at 1198-99.) He also indicated that the uniform cents per kWh methodology agreed to in the CIGFUR Stipulation is consistent with the method used to calculate the North Carolina EDIT Rider approved by the Commission in the Company's last rate case. (*See* id. at 28, 1244-45.)

CIGFUR witness Phillips testified that he agrees with the Company's rate design methodology of reducing subsidies uniformly by 25% and that the allocation of EDIT credits on a uniform cents per kWh basis would enhance that subsidy reduction and move rates closer to cost.

> The 25 percent is a way of moderating any rate increases to classes, but it only gets you one-fourth of the way toward cost. So the method [DEP] and CIGFUR have agreed to and the Commission has previously approved to pass back the tax credits moves a little bit farther than the 25 percent and would help get rates closer to cost.

(Tr. vol. 14, 358-59; *see also,* id. at 344.) In addition, he explained in Docket E-2, Sub 1188, DEP passed back more than $100 million on a uniform cents per kWh hour basis, and "I think that order says it was previously done in a previous case on some state taxes in that same way."[8] (Id. at 359.)

Based on the evidence in the record, and consistent with the way in which North Carolina EDIT was flowed back to customers in Docket Nos. E-7, Sub 1146 and E-2, Sub 1142, the Commission finds and concludes that unprotected EDIT and deferred revenue should be refunded to customers on a uniform cents per kWh basis as provided in the CIGFUR Stipulation and as illustrated in Pirro Second Settlement Exhibit 8. In reaching this conclusion, the Commission gives great weight to the testimony of witness Pirro that continuation of a trend toward rate parity by reducing subsidy/excess levels would be desirable and that flowing back EDIT on a uniform cents per kWh helps balance out historical subsidization of the residential class by other customers.

Rate Design for the LGS, LGS-TOU, and LGS-RTP Schedules

The large general service rate class includes all nonresidential customers with demand requirements of 1,000 kW or greater and includes the following rate schedules: Large General Service (LGS), Large General Service Time-of-Use (LGS-TOU), and Large General Service (Real Time Pricing) (LGS-RTP). (Tr. vol. 11, 1099.) The majority

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[8] *See* Order Approving Proposal and Requiring Filing of Revised Tariffs, Docket No. E-2, Sub 1188 (Nov. 26, 2018) (approving DEP's request to reduce rates to reflect the reduction in the federal corporate income tax rate by implementing a 0.278 cents per kWh rate decrement applicable to all customers, but noting that the Commission's decision was based upon the facts and circumstances in that case and should not be considered precedential); *see also,* Order Approving Rate Adjustment and Notice to Customers, Docket No. E-2, Subs 1174 and 1192 (Dec. 17, 2018) (approving rate reduction requested by DEP associated with State income tax reduction by implementing a uniform 0.002 cents per kWh decrement, noting that the Commission's approval was granted at the request of DEP to make a voluntary reduction in its rates outside of a general rate case, and should not be cited in future proceedings as precedential).

of usage under LGS-RTP is billed as the Customer Baseline Load (CBL) under Schedules LGS or LGS-TOU, so it is not shown separately in the Company's data, but is included within the schedule used for billing the CBL. (Id. at 1100.)

In his direct testimony, witness Pirro described the Company's proposed rate design for the LGS rate schedules. (Id. at 1100-01.) He noted that the Basic Customer Charge would remain unchanged for all schedules. (Id.) He also indicated that the Company proposed to update the transformation-ownership discount to reflect the unit cost study. (Id. at 1101.) With respect to the LGS Schedule, witness Pirro testified that the demand rates are currently "blocked" to recognize that customers with larger load are typically served from fewer delivery-related facilities. (Id. at 1100.) The current demand block structure of $1 per kW reduction for loads above 5,000 kW and a $2 per kW reduction for loads above 10,000 kW is proposed to continue, as supported by the unit cost study. (Id.) The kW demand and kWh energy rates are increased by the same percentage to achieve the requested revenue. (Id.) With respect to the LGS-TOU Schedule, witness Pirro testified that the Company is not proposing changes to the TOU period hours, nor is it proposing any structural changes to LGS-TOU. (Id.) The on-peak demand rates are increased by the same percentage as the energy rate adjustment. (Id.) The off-peak excess kW charge is increased to reflect the LGS distribution-related unit cost study. (Id.) The kWh energy rates are adjusted to reflect the increase in revenue, retaining the current 0.5 cents per kWh differential between on-peak and off-peak energy rates. (Id. at 1101.) Finally, with respect to LGS-RTP, witness Pirro testified that the majority of usage received under LGS-RTP is billed in the CBL at standard tariff rates; however, the Company proposed to update the Facilities Demand Charges to more accurately recover the cost of delivering electricity to the customer's site, and the tax factor applicable to the hourly rate is also revised to recover the current Regulatory Fee. (Id.)

Witness Phillips testified that DEP's proposed rate design for the Large General Service customer class understates the demand charges while overstating the energy charges relative to the unit costs from DEP's cost of service study. (Tr. vol. 14, 310.) He indicated that DEP's proposed energy charges exceed the unit cost of energy by more than 100%. (Id.) He argued that DEP's proposed rates do not reflect unit costs or the winter peak demand used by DEP for planning. (Id. at 293, 310.) Therefore, he recommended that any reduction to DEP's requested increase should be applied to reduce energy charges to achieve the authorized revenue level for Rate LGS. (Id.)

In § V.F. of the CIGFUR Stipulation, CIGFUR and DEP agree that for the LGS, LGS-TOU, and LGS-RTP Schedules, the on-peak and off-peak energy charges shall be increased by a percentage that is less than half of the approved overall percentage increase (exclusive of any EDIT decrements). The parties further agree that the demand charges for each of the LGS, LGS-TOU, and LGS-RTP schedules shall be adjusted by the amount necessary to recover that schedule's respective final revenue target. (*See* id.)

The Commission observes that the rate design provisions outlined in § V.F. of the CIGFUR Stipulation apply only to the LGS, LGS-TOU, and LGS-RTP rates proposed in *this* rate case. These provisions do not bind the Company – or the Commission – to any particular rate design structure in a future rate case and do not limit the Company's ability to study alternative rate designs. As discussed in the Evidence and Conclusions for Finding of Fact No. 45, the Commission gives weight to testimony from witnesses Huber and Pirro to the effect that the Company views the comprehensive rate design study as a "blank slate." In addition to evaluating new and innovative rate designs and exploring the topics discussed in the direct testimony of witness Floyd as well as witness Huber, it is clear from the evidence presented that DEP plans to use the study as an opportunity to review and reevaluate all of its existing tariffs, to include its large general service schedules. Moreover, testimony from witness Phillips explaining that the energy charges for the LGS rate schedules are priced significantly higher than unit costs for energy and recommending a gradual move toward cost, supports the stipulated changes to the LGS, LGS-TOU, and LGS-RTP rate design agreed to in the CIGFUR Stipulation, and no intervenor offered any testimony challenging the substantive aspects of these modifications. Accordingly, the Commission finds and concludes that the rate design for the LGS, LGS-TOU, and LGS-RTP rate schedules should be modified as DEP has agreed in § V.F. of the CIGFUR Stipulation.

Other Rate Design and Cost Allocation Issues

The remaining provisions of the CIGFUR Stipulation pertain to items the Company has agreed to either consider or propose in the future. The Commission notes that its finding that these provisions are just and reasonable as part of its overall approval of the CIGFUR Stipulation of course does not bind the Commission to approve the methodologies proposed therein or otherwise serve as precedent in future rate cases or other proceedings. In addition, the Public Staff and other parties are free to contest or endorse the cost allocation methodologies and rate design proposals the Company has agreed to make in future rate cases or other proceedings pursuant to the CIGFUR Stipulation just as they would be in the absence of these provisions. In addition, the Public Staff and other parties are free to contest or endorse the cost allocation methodologies and rate designs the Company has agreed to propose in future rate cases or other proceedings pursuant to the CIGFUR Stipulation, just the same as the Public Staff and other parties could in the absence of these provisions.

The CIGFUR Stipulation provides that DEP and CIGFUR agree to meet prior to the Company's next general rate case to discuss potential cost of service methodologies that the Company may recommend for the purpose of allocating production and transmission costs. (CIGFUR Stipulation, § V.A.) In addition, the parties agreed that in its next rate case, DEP should file the results of a class cost of service study with production and transmission costs allocated on the basis of the Summer/Winter Coincident Peak method and consider such results for the sole purpose of apportionment of the change in revenue to the customer classes. (Id.) In this provision, the Company simply agrees to consider using the Summer/Winter Coincident Peak Method in its next rate case; the Company does not agree to recommend, support, or propose this method. (*See* Tr. vol. 11, 1252-53.) Further, Summer/Winter Coincident Peak is just one method among many that the Company has agreed to investigate prior to its next rate case (which is clear from the fact that in the same provision, the Company agrees to meet and discuss with CIGFUR more generally the potential methodologies the Company may recommend for allocating production and transmission costs in its next case). In addition, as discussed in Evidence and Conclusions for Findings of Fact Nos. 36-40, the Company has agreed to evaluate no less than six cost allocation methodologies pursuant to the Second Partial Stipulation. (*See* id. at 1253.) Further, that DEP agreed to file the Summer/Winter Coincident Peak Method does not in any way bind the Company to use this method, nor would it bind the Commission to approve such method if the Company were to use it. The Company routinely files multiple cost-of-service studies as part of its rate case Application, but only recommends one. (*See* id.; Tr. vol. 15, 78-79.) Moreover, Summer/Winter Coincident Peak is simply an average of two of the methods the Company has already agreed to run – SCP and WCP – pursuant to the Second Partial Stipulation with the Public Staff. (*See* Tr. vol. 11, 1276; Second Partial Stipulation, IV.B.)

The CIGFUR Stipulation also provides that in its next three general rate cases, the Company will propose to allocate distribution expenses using the minimum system method. (CIGFUR Stipulation, § V.D.) In the event the Commission orders a different approach for allocating distribution expenses, the Company may, but is not obligated to, propose the minimum system method. (*See* id.) As discussed in the Evidence and Conclusions in Support of Findings of Fact Nos. 36-40, the Commission finds that the Company's use of the minimum system method to allocate customer-related distribution costs is reasonable and appropriate for the purpose of allocating costs to the respective rate classes in this rate case. As such, pursuant to the CIGFUR Stipulation, the Company is obligated to propose the minimum system approach in its next general rate case. (*See* CIGFUR Stipulation, § V.D.) Along the same lines, DEP and CIGFUR agreed that in its next rate case, the Company will propose to allocate deferred GIP costs among the customer classes consistent with its distribution cost allocation methodologies proposed in this docket, including use of the minimum system method and use of voltage differentiated allocation factors for distribution plant. (CIGFUR Stipulation, § III.B.) The Commission takes no position as to whether minimum system method will be appropriate for DEP in the future, but recognizes that DEP has used the minimum system method for decades and has strongly advocated for this method anytime it has been challenged. The Company is certainly free to agree to continue to propose and support the minimum system method in the future if it so chooses, just as intervenors are free to challenge this method in the future if they so choose. Likewise, the Commission takes no position in this rate case on cost allocation of deferred GIP costs, as it would be premature to do so until such time as the Company is actually seeking to recover such deferred costs in its next general rate case.

In the CIGFUR Stipulation, DEP has also agreed that in its next rate case, it will adjust its peak demand to remove curtailable/non-firm load, even if it does not call this load. (CIGFUR Stipulation, § V.B.) If the Commission approves this adjustment in the Company's next rate case, then DEP will propose use of this adjustment in its next subsequent rate case. (Id.)

The Public Staff suggested that this adjustment would be inappropriate for DEP. (Tr. vol. 15, 1003-04.) While witness Floyd acknowledged that he had previously supported this type of adjustment in Dominion's 2012 rate case in Docket No. E-22, Sub 479 (Sub 479 Case), he indicated that his support was based on the following factors: (1)

Dominion had activated all of its DSM resources and interruptible loads at the time of its summer peak in the Sub 479 Case test year, but only activated a portion of those resources at the time of its winter peak, and thus, the relationship between the summer and winter peaks was distorted without the adjustment; and (2) Dominion relied upon the SWPA cost of service methodology in the Sub 479 Case, and therefore, even those customers who could contribute to reducing their peak loads could not avoid all production plant cost responsibility for the interruptible portion of their loads that was present in the other hours of the year due to the average demand component of SWPA. (Id.) He noted DEP activated some of its DSM and interruptible resources at the time of its test year summer and winter peaks, and summer and winter peaks for the test year already incorporate the effects of the reduced demand associated with these resource activations. (Id. at 1004.) While the resources that were activated represent only a portion of the available demand response resources, the affected customer classes received the benefit of a reduced peak demand allocator in this case. (Id.) In any event, the Public Staff's position on the appropriateness of this adjustment for DEP was based on the test year and factual circumstances in this rate case, and this provision of the CIGFUR Stipulation does not apply to this rate case. (Tr. vol. 11, 1253-54.) During cross-examination, witness Floyd and witness McLawhorn indicated that whether the Public Staff would oppose this adjustment in the future would depend upon the cost allocation methodology and whether the Company actually utilized its interruptible and DSM resources. (Tr. vol. 15, 1095-96.)

Witness Phillips provided several reasons why, in his view, an adjustment to remove curtailable load may be appropriate. (*See* Tr. vol. 14, 337-38.) For example, he testified that if the Company has curtailable load, it does not need to build or buy capacity to serve that load, so it is correct to remove that load from the demand allocator. (*See* id.) Notwithstanding, he concluded that the points he raised need to be "discussed and hammered out. And we don't have a proposal before us today with testimony explaining it, and that's why I'm hesitant to prolong this, because I don't think this issue is before the Commission now." (Id. at 338.) As witness Phillips appropriately pointed out, this issue is not before the Commission in this case, and as the Public Staff witnesses testified, whether the Public Staff would support or oppose such an adjustment would depend on the facts and the circumstances of the particular case. DEP is free to propose and support this adjustment in its next rate case, and the Public Staff and other intervenors are free to take any position they would like at that time.

In § V.C of the CIGFUR Stipulation, the Company agrees that in its next two annual fuel cost recovery proceedings, it will propose the uniform percentage average bill adjustment methodology that was most recently approved by the Commission in the Company's 2019 fuel cost recovery proceeding. The Company is welcome to propose this methodology in its fuel cost recovery proceedings in 2021 and 2022, and the Commission will evaluate whether it is appropriate under the evidence in those cases.

CIGFUR witness Phillips provided testimony on a number of rate design topics, including a recommendation that DEP should allow existing RTP customers the opportunity to adjust CBLs in order to help mitigate sluggish industrial sales and benefit the system. (Tr. vol. 14, 293, 311.) In the CIGFUR Stipulation, the Company agreed to explore: (1) a rate schedule targeted at high load users similar to Duke Energy Indiana's

HLF rate; (2) allowing RTP customers the opportunity to adjust CBLs to enhance RTP usage, including additional special periods of adjustment; (3) an emergency demand response program similar to Southern California Edison's Time-of-Use Base Interruptible tariff; and (4) a rate schedule similar to the Northern Indiana PSC Interruptible Industrial Service Rider. (CIGFUR Stipulation, § V.E.) The CIGFUR Stipulation provides that if the Company undertakes a comprehensive rate design process prior to the Company's next general rate case, such process would be the proper venue for such consideration. (*See* id.) Further, if there is mutual agreement between CIGFUR and the Company on any of the terms of the above-referenced rates, and CIGFUR indicates that at least one of its members is willing to take service under such rates, the Company agrees to file said rates for Commission approval in its next rate case. (*See* id.) Again, this provision does not bind the Commission to rule in any way in future rate cases and does not even require the Company to propose a certain rate unless, through the comprehensive rate design process, it finds such a rate would be appropriate and it is able to reach agreement with CIGFUR on the terms of such a rate.

In summary, as witness Phillips expressed in his live testimony,

> The things that Duke agreed to present in a future case would be subject to review in the future case, and the Public Staff could comment on anything they disagree with at that time instead of now….All of the things that we asked for in the future are contingent on Commission approval…I don't think two parties can enter a settlement that tie the Commission's hands in a future case.

(Tr. vol. 14, 336-37; *see also,* id. at 360.) Subsequently, in response to questioning by the Commission, witness Phillips testified that "[w]e understand that just because Duke proposes something, or CIGFUR, or anyone proposes something in the next general rate case, that the ultimate decision is with the Commission, and any party can write testimony or briefs and take a different position. We're just bringing out that we want Duke to continue this treatment that it's sound cost causation, and keep doing it." (Id. at 347.)

The Commission agrees with this testimony from witness Phillips that the Commission would not be bound to accept or approve any of the cost allocation or rate design matters the Company stipulated with CIGFUR to propose in future rate cases. Therefore, the Commission does not take any issue with these provisions of the CIGFUR Stipulation and approves them as part of its approval of the CIGFUR Stipulation as a whole.

Discussion and Conclusions

As with the Second Partial Stipulation, because the CIGFUR Stipulation has not been adopted by all of the parties to this docket, the Commission's determination of whether to accept or reject the CIGFUR Stipulation is governed by the standards set forth by the North Carolina Supreme Court in *CUCA I* and *CUCA II*.

The Commission gives significant weight to the testimony of DEP witnesses Hager and Pirro regarding the Company's support for the CIGFUR Stipulation. The Commission likewise gives significant weight to the testimony of witness Phillips regarding CIGFUR's support for the CIGFUR Stipulation.

As a result, the Commission finds and concludes that the CIGFUR Stipulation is the product of the give-and-take between CIGFUR and the Company during their settlement negotiations in an effort to appropriately balance the parties' positions. In addition, the Commission finds and concludes that the CIGFUR Stipulation was entered into by DEP and CIGFUR after discovery and negotiations, and that it represents a proposed negotiated resolution of the matters in dispute between the Company and CIGFUR in this docket. Finally, the Commission finds and concludes that the CIGFUR Stipulation is fair, reasonable, and in the public interest. As a result, the CIGFUR Stipulation is material evidence to be given appropriate weight in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 65

The evidence supporting these findings and conclusions is contained in DEP's verified Application and Form E-1, the testimony and exhibits of Company witnesses De May, Oliver and C. Barnes; NCJC et al. witness Howat; NCSEA and NCJC et al. witnesses Alvarez and Stephens; the NCSEA and NCJC et al. Stipulation, and the entire record in this proceeding.

On July 23, 2020, DEP filed the NCSEA and NCJC et al. Stipulation which resolves certain issues in this proceeding between the parties, including the appropriate rate of return and capital structure for setting rates in this proceeding, the Company's proposed GIP, and provides for shareholder contributions to the Helping Home Fund, collaboration on Low-Income EE/DSM Pilot programs, collaboration on a Tariffed On Bill Pilot Program, and agreement by the Company to publish a Distributed Generation Guidance Map and provide Hosting Capacity Analyses.

As the NCSEA and NCJC et al. Stipulation has not been adopted by all of the parties to this docket, as previously discussed in our discussion of the Public Staff Partial Stipulations, its acceptance by the Commission is governed by the standards set out in *CUCA I* and C*UCA II*.

The Commission credits the testimony of the Company, NCSEA, and NCJC et al. witnesses concerning the issues that are settled in the NCSEA and NCJC et al. Stipulation and finds and concludes that the NCSEA and NCJC et al. Stipulation is the product of the give-and-take negotiations between DEP, NCSEA and NCJC et al., in an effort to appropriately balance the Company's need for rate relief with the impact of such rate relief on customers. The NCSEA and NCJC et al. Stipulation is, therefore, material evidence to be given appropriate weight in this proceeding.

As detailed below, there is ample evidence in the record to support all of the provisions of the NCSEA and NCJC et al. Stipulation, including those that have been contested by some intervenors. Accordingly, the Commission is fully justified in adopting the NCSEA and NCJC et al. Stipulation through the exercise of its own independent judgment, and finding and concluding through such independent judgment that the

NCSEA and NCJC et al. Stipulation "is just and reasonable to all parties in light of all the evidence presented." CUCA I, 348 N.C. at 466. The Commission hereby adopts the NCSEA and NCJC et al. Stipulation in its entirety, and the conclusions as to the individual provisions of the NCSEA and NCJC et al. Stipulation are set forth more fully below.

Rate of Return and Capital Structure

As discussed in the Evidence and Conclusions for Findings of Fact Nos. 26-32, as part of the NCSEA and NCJC et al. Stipulation, DEP initially agreed that the revenues to be approved in this proceeding should be adjusted to provide the Company, through sound management, the opportunity to earn an ROE of 9.75% and that this ROE will be applied to the common equity component of the ratemaking capital structure consisting of 52% equity and 48% long-term debt. (NCSEA and NCJC et al. Stipulation, § 2.) Subsequently, DEP and the Public Staff entered into the Second Partial Stipulation which, among other things, stipulated to an ROE of 9.6%. The parties to the NCSEA and NCJC et al. Stipulation amended their agreement to recognize that if the Commission issues an order approving an ROE of 9.6%, the parties to the NCSEA and NCJC et al. Stipulation agree that the provisions of their respective agreements regarding ROE have been met. As discussed in the Evidence and Conclusions for Findings of Fact Nos. 26-32, the Commission finds 9.6% to be a reasonable ROE for DEP and finds 52% equity and 48% debt to be a reasonable capital structure for DEP in this general rate case.

Grid Improvement Plan

As discussed in the Evidence and Conclusions for Findings of Fact Nos. 33-35 and 66, as part of it settlement agreement with DEP, NCSEA and NCJC et al. support the approval of DEP's requested GIP deferral with certain conditions detailed therein, including a reservation of NCSEA and NCJC et al.'s right to review and object to the reasonableness of specific GIP costs in future rate cases. (*See* NCSEA and NCJC et al. Stipulation, § III.) In addition, the parties agreed to the extent DEP enters into an agreement with other intervening parties agreeing to a cost cap or to limit the amount of any GIP investment category specified for deferral treatment, NCSEA and NCJC et al. support such cost containment measure (Id.) As discussed in the Evidence and Conclusions for Findings of Fact Nos. 33-35 and 66, the Commission finds the GIP-related provisions of the settlements between the Company NCSEA and NCJC et al. supporting or not opposing GIP implementation, are reasonable and appropriate.

Helping Home Fund

As noted earlier, DEP witness De May testified that DEP is committed to helping customers who struggle to pay for electricity service with programs and options to assist them during times of financial hardship and that DEP wants to do even more for these customers, particularly those most in need, and are considering ways for the Company and its customer base to continue to be good stewards. (Tr. vol. 11, 756.) NCJC et al. witness Howat supported witness De May's commitment to addressing these affordability issues and underscored that electricity service is a necessity in present-day society. (Tr. vol. 14, 377.) Witness Howat stated that increased contributions to the Helping Home

Fund would help address these affordability challenges faced by customers and would mitigate the impacts of a rate increase. (Tr. vol. 14, 394.) The Helping Home Fund is a program administered by the North Carolina Community Action Association and offered through a network of community action agencies that serve households in DEC and DEP service territories. (Id.) The Helping Home Fund program delivers weatherization services, heating and cooling system repairs, appliance replacements and critical health and safety repairs at no cost to DEC and DEP customer households at or below 200% of federal poverty guidelines. (Id; *see also "Evaluation of Duke Energy's Helping Home Fund," Advanced Energy,* (Oct. 15, 2017), Official Ex. vol. 14, redacted, 300 (Ex. JH-5).) Witness Howat testified that programs like the Helping Home Fund help low-income households have a higher likelihood of maintaining essential electric service. (Tr. vol. 14, 393.)

As part of the NCSEA and NCJC et al. Stipulation, the Company agreed to provide, in conjunction with DEC, an aggregate combined shareholder-funded contribution to the Helping Home Fund of $3 million per year for two years (for a total of $6 million). (NCSEA and NCJC et al. Stipulation, § IV.)

No intervenors took issue with this provision of the NCSEA and NCJC et al. Stipulation. Accordingly, the Commission finds and concludes that consistent with the terms of the settlement, and in light of all the evidence presented, the Helping Home Fund contributions are approved.

Low-Income EE/DSM

NCJC et al. witness Howat testified that low-income energy efficiency programs "provide the cornerstone of low-income energy security." (Tr. vol. 14, 132-33.) Witness Howat emphasized that energy efficiency programs are an important complement to affordable rate designs. (Id.) DEP witness De May agreed with witness Howat that development of new low-income energy efficiency programs are important steps towards improving affordability. (Tr. vol. 11, 824-26.) In addition, DEP witness C. Barnes testified that the Company understands that many customers have difficulty paying their energy bills and underscored the value in taking a collaborative approach to addressing these issues. (Id. at 176.)

As part of the NCSEA and NCJC et al. Stipulation, the Company agreed to collaborate with NCSEA and NCJC et al. in designing low-income EE/DSM program pilots. (NCSEA and NCJC et al. Stipulation, § V.) Those program pilots will then be presented to the EE/DSM Collaborative participants listed in the Direct Testimony of Robert P. Evans, filed June 9, 2020 in Docket No. E-2, Sub 1252, along with the Company. (Id.) If a majority of the EE/DSM Collaborative participants support the program, the Company agreed to file for approval of the pilot programs in both North Carolina and South Carolina. (Id.) If the Company, NCSEA, and NCJC et al. agree on programs to file on a non-pilot basis, they agreed to file a joint petition with the Commission for approval. (Id.)

No intervenors took issue with this provision of the NCSEA and NCJC et al.

Stipulation. Accordingly, the Commission finds and concludes that consistent with the terms of the settlement, and in light of all the evidence presented, the terms of the settlement regarding the Low-Income EE/DSM Pilot Program is approved.

Tariffed On-Bill Pilot Program

A tariffed on-bill program allows a utility to make energy efficiency investments at a participating customer's premises that are tied to the meter and recovered over time with a tariff on that customer's bill. (NCJC et al. Late-Filed Ex. No. 3, Attachment 3, 147.) The Commission has previously received testimony that the implementation of a tariffed on-bill program would not be cost effective until the Company's new customer information system was deployed. (*See* Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice, 27, Docket No. E-2, Sub 1206 (December 13, 2019).)

The NCSEA and NCJC et al. Stipulation sets forth that the Company and NCSEA and NCJC et al. will examine a number of issues related to the implementation of a tariffed on-bill program. The Company has further agreed to file with the Commission a tariffed on-bill pilot program, if the parties to the stipulation agree on program terms, or a status report within 18 months. Thus, the NCSEA and NCJC et al. Stipulation contemplates that the tariffed on-bill pilot program will be implemented after the Company deploys its new customer information system, addressing concerns previously raised to the Commission.

No intervenors took issue with this provision of the NCSEA and NCJC et al. Stipulation. Accordingly, the Commission finds and concludes that consistent with the terms of the settlement, and in light of all the evidence presented, the terms of the settlement regarding the Tariffed On-Bill Pilot Program are approved.

Distributed Generation Guidance Map / Hosting Capacity Analyses

Hosting capacity is defined as the amount of distributed generation (DG) that can be accommodated on a distribution circuit without degrading reliability and power quality. (Tr. vol. 13, 45-46, Docket No. E-2, Sub 1142.[9])

Witness Oliver's testimony and exhibits clearly indicate that the projects comprising the GIP will increase the Company's hosting capacity. (*See* generally, Exs. vol. 11.) While there is not universal agreement among the parties about how much the Company's hosting capacity will increase, no party disagrees with witness Oliver's testimony that the GIP will increase the Company's hosting capacity. However, without guidance as to circuits and geographic locations where hosting capacity has increased, customers and DG developers cannot identify preferred locations for interconnection. Utilizing hosting capacity analyses to create DG guidance maps, or hosting capacity

[9] In its Order Scheduling Investigation and Hearings, Establishing Intervention and Testimony Due Dates and Discovery Guidelines, and Requiring Public Notice, issued on December 6, 2019, the Commission took judicial notice pursuant to N.C.G.S. § 62-55 "of all evidence, decisions and other matters of record pertaining to coal combustion residuals (CCRs), Advanced Metering Infrastructure (AMI), and Power Forward in DEP's last general rate case, Docket No. E-2, Sub 1142[.]"

maps, will allow customers and DG developers to identify preferred locations for interconnection, streamlining the interconnection process through fewer delays and reduced uncertainty. (Tr. vol. 7, 165-166, Docket No. E-2, Sub 1142; Tr. vol. 13, 45, Docket No. E-2, Sub 1142.)

The NCSEA and NCJC et al. Stipulation provides that the Company will preview a Distributed Generation Guidance Map to stakeholders through the interconnection Technical Standards Review Group (TSRG) and the Integrated System & Operations Planning (ISOP) stakeholder meetings before making hosting capacity analyses available for a representative sample of the Company's circuits in the future. While not initially included in the GIP proposal, Distributed Generation Guidance Maps are directly related to the GIP plan.

The NCSEA and NCJC et al. Stipulation also sets forth a process for the Company to integrate ISOP into its integrated resource planning process and for further stakeholder engagement in the development of tools and capabilities for ISOP implementation. While ISOP was included in the GIP, details of its integration into the integrated resource planning process and stakeholder engagement were not.

No intervenors took issue with this provision of the NCSEA and NCJC et al. Stipulation. Accordingly, the Commission finds and concludes that consistent with the terms of the settlement, and in light of all the evidence presented, the terms of the settlement regarding the Distributed Generation Guidance Map and Hosting Capacity Analyses are approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 66

The evidence supporting these findings and conclusions is contained in the Vote Solar Stipulation, DEP's verified Application and Form E-1, the testimony and exhibits of Vote Solar witnesses Fitch and Van Nostrand, and the entire record in this proceeding.

On July 9, 2020, DEP filed the Vote Solar Stipulation which resolves certain issues in this proceeding between the parties, including the appropriate rate of return and capital structure for setting rates in this proceeding, the Company's proposed GIP, and provides for Climate Risk and Resilience Planning through a working group.

As the Vote Solar Stipulation has not been adopted by all of the parties to this docket, as previously discussed in our discussion of the Public Staff Partial Stipulations, its acceptance by the Commission is governed by the standards set out in *CUCA I* and C*UCA II*.

The Commission credits the testimony of the Company and Vote Solar witnesses concerning the issues that are settled in the Vote Solar Stipulation and finds and concludes that the Vote Solar Stipulation is the product of the give-and-take negotiations between DEP and Vote Solar in an effort to appropriately balance the Company's need for rate relief with the impact of such rate relief on customers. The Vote Solar Stipulation is, therefore, material evidence to be given appropriate weight in this proceeding.

As detailed below, there is ample evidence in the record to support all of the provisions of the Vote Solar Stipulation, including those which have been contested by some intervenors. Accordingly, the Commission is fully justified in adopting the Vote Solar Stipulation through the exercise of its own independent judgment, and finding and concluding through such independent judgment that the Vote Solar Stipulation "is just and reasonable to all parties in light of all the evidence presented." CUCA I, 348 N.C. at 466. The Commission hereby adopts the Vote Solar Stipulation in its entirety, and the conclusions as to the individual provisions of the Vote Solar Stipulation are set forth more fully below.

Rate of Return and Capital Structure

As discussed in the Evidence and Conclusions for Findings of Fact Nos. 26-32, as part of the Vote Solar Stipulation, DEP initially agreed that the revenues to be approved in this proceeding should be adjusted to provide the Company, through sound management, the opportunity to earn an ROE of 9.75% and that this ROE will be applied to the common equity component of the ratemaking capital structure consisting of 52% equity and 48% long-term debt. (Vote Solar Stipulation, § 2.) Subsequently, DEP and the Public Staff entered into the Second Partial Stipulation which, among other things, stipulated to an ROE of 9.6%. The parties to the Vote Solar Stipulation amended their agreement to recognize that if the Commission issues an order approving an ROE of 9.6%, the parties to the Vote Solar Stipulation agree that the provisions of their respective agreements regarding ROE have been met. As discussed in the Evidence and Conclusions for Findings of Fact Nos. 24-30 the Commission finds 9.6% to be a reasonable ROE for DEP and finds 52% equity and 48% debt to be a reasonable capital structure for DEP in this general rate case.

Grid Improvement Plan

As discussed in the Evidence and Conclusions for Findings of Fact Nos. 33-35 and 66, as part of it settlement agreement with DEP, Vote Solar supports the approval of DEP's requested GIP deferral with certain conditions detailed therein, including a reservation of Vote Solar's right to review and object to the reasonableness of specific GIP costs in future rate cases. (*See* Vote Solar Stipulation, § III.2.) In addition, the parties agreed to the extent DEP enters into an agreement with other intervening parties agreeing to a cost cap or to limit the amount of any GIP investment category specified for deferral treatment, Vote Solar supports such cost containment measure (Id. at § III.1.) Finally, DEP commits to develop potential pilot customer programs prior to the submission of the 2022 Integrated Resource Plan (IRP) to optimize the capability of the GIP investments to support greater utilization of distributed energy resources. (Id.) As discussed in the Evidence and Conclusions for Findings of Fact Nos. 33-35 and 66, the Commission finds the GIP-related provisions of the settlements between the Company and Vote Solar supporting or not opposing GIP implementation, are reasonable and appropriate.

Climate-Resilience Planning

Vote Solar presented extensive evidence of the evolution of risk assessment in the utility, investment and finance, and insurance industries to include and incorporate the impacts of climate change and climate risk on the assets and operations of electric utilities. While still a nascent and evolving field, Vote Solar presented evidence of trends in other jurisdictions where evaluation of climate risk is becoming part of the regulatory review process and is being proactively incorporated into utility planning processes to address and mitigate foreseeable risks associated with climate change to the distribution and transmission grids of electrical utilities.

In § IV of the Vote Solar Stipulation, DEP agrees to convene a Climate Risk & Resilience Working Group (Working Group) that will assist in the development of models and analytical tools or techniques to study and integrate the effects of climate change into distribution and transmission system planning. The Working Group will also assist in developing an implementation plan based on the analytical tools developed that will be filed as part of the 2024 IRP proceeding, or in a proceeding otherwise designated by the Commission.

DEP will submit a scoping plan for the Working Group within sixty days of a final order and will provide notice to interested parties in North Carolina and South Carolina of the opportunity to participate in the Working Group. DEP will select and fund a third-party consultant with experience modelling climate-related impacts and will ultimately seek cost recovery in a future proceeding. DEP also agrees to coordinate with the North Carolina Department of Environmental Quality to align the scope and proposed schedule of the Working Group to avoid duplication or scheduling conflicts with the forthcoming phase of the State Climate Risk Assessment and Resilience Plan.

No intervenors took issue with this provision of the Vote Solar Stipulation. Accordingly, the Commission finds and concludes that consistent with the terms of the settlement, and in light of all the evidence presented, the terms of the settlement regarding Climate-Resilience Planning are approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 67

The evidence supporting this finding and conclusion is contained in the Company's verified Application and Form E-1; the testimony and exhibits of DEP witness Pirro and Public Staff witness Floyd; and the entire record in this proceeding.

The Company's Rate Schedule R-TOUD is a residential time-of-use rate whereby customers are billed a Basic Customer Charge, on-peak demand charge, and energy charge based on on-peak and off-peak usage monthly. (Tr. vol. 11, 1127.) R-TOUD is available for existing residential customers if: (1) the customer also receives service under the New Metering for Renewable Energy Facilities Rider (Rider NM); or (2) the customer was served under R-TOUD before December 1, 2013 and has not terminated or switched to another available schedule. (*See* id. at 1128.)

Rate Schedule R-TOUD was closed to new participants as a result of the Commission's approval of a Stipulation between the Company and the Public Staff in DEP's rate case, Docket No. E-2, Sub 1023. (Tr. vol. 15, 959.) Witness Pirro explained that in Docket No. E-2, Sub 1023, the Company created a new time-of-use tariff, R-TOU, and wanted a single rate design for residential time-of-use customers. (Tr. vol. 11, 1128.) At that time, restricting the availability of R-TOUD allowed the Company to more effectively communicate with customers regarding the benefits of a TOU rate design and minimize potential customer confusion regarding the new TOU hours and the billing determinants. (Id.) Witness Pirro testified that in comparison to Schedule R-TOUD, Schedule R-TOU offers improved time periods, improved pricing signals, and no demand charges. (Id.)

Public Staff witness Floyd explained that Schedule R-TOUD bills service using demand and energy rates, rather than an energy-only structure. (Tr. vol. 15, 960.) He indicated that the Public Staff has received a number of requests from customers over the years, who would like service under a demand and energy structure. (Id.) He argues that given the deployment of smart meters and the Company's initiatives to provide customers with more choices concerning their energy consumption, Schedule R-TOUD is ready-made to provide that choice now. (Id.) Therefore, he recommended that the Commission should reopen Schedule R-TOUD. (Id.)

In his rebuttal testimony, witness Pirro indicated that the Company does not disagree with witness Floyd that the Company should provide customers with more choices regarding their energy consumption. (Tr. vol. 11, 1128.) However, the Company did not contemplate re-opening R-TOUD at the onset of its rate case planning. (Id. at 1128-29.) He testified that had DEP contemplated reopening R-TOUD, the Company would have likely recommended other changes to the R-TOUD tariff and/or to the R-TOU tariff. (Id. at 1129.) Also, a migration adjustment would be required to give the Company an opportunity to realize its full revenue requirement. (Id.) The Company believes that reopening R-TOUD and/or creating another residential time-of-use tariff should be considered in the comprehensive rate design study. (Id.)

The Commission agrees that the Company's time-of-use rate offerings should be evaluated by the Company. However, based on the testimony of witness Pirro, the Commission believes that simply reopening R-TOUD to new customers without considering the broader implications, such as the potential for migration and whether the rate needs to be modified prior to being opened up to new participation, is not appropriate at this time. Instead, DEP should consider reopening R-TOUD and/or developing another residential time-of-use tariff as part of the rate design study outlined in the Second Partial Stipulation.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 66

The evidence supporting these findings and conclusion is contained in the Company's verified Application and Form E-1, the testimony and exhibits of Company witnesses McManeus, Oliver, NCSEA and NCJC et al. witnesses Alvarez and Stephens, the Second Partial Stipulation, the Customer Group Stipulations, the Vote Solar Stipulation, the NCSEA and NCJC et al. Stipulation, and the entire record in this proceeding.

Prior to the evidentiary hearing, in addition to the Second Partial Stipulation discussed in Evidence and Conclusions for Findings of Fact Nos. 8-10, the Company entered into separate settlement agreements with several parties that filed testimony in opposition to its GIP proposals. These included Harris Teeter, the Commercial Group, CIGFUR, Vote Solar, NCSEA and NCJC et al. and are referred to herein collectively as the Intervenor Stipulations. Each of these settlements, as they relate to GIP program proposals, is discussed below.

Harris Teeter Stipulation

On June 8, 2020, DEP and Harris Teeter entered into the Harris Teeter Stipulation resolving some of the issues in this proceeding between the two parties. The Harris Teeter Stipulation provides, in pertinent part, that Harris Teeter supports the approval of a GIP deferral as requested by DEP in this docket. (Harris Teeter Stipulation, § 1.) Additionally, the Harris Teeter Stipulation specifies that to the extent that DEP enters into an agreement with other intervening parties agreeing to a cost cap or to otherwise limit the maximum allowed amount of DEP's GIP deferral, Harris Teeter supports such cost containment measures. (Id.) Further, the Harris Teeter Stipulation states that Harris Teeter is not prevented from taking any position in future cost recovery proceedings regarding the reasonableness of specific GIP program or subprogram costs. (Id.) In addition, DEP agreed that any GIP costs allocated to SGS-TOU customers would be recovered via demand charges. (Id. at § 2.)

The Commercial Group Stipulation

On June 9, 2020, DEP and a group of commercial customer intervenors designated as the Commercial Group, filed the Commercial Group Stipulation in this proceeding. This settlement provides that pursuant to the agreement of the parties, the Commercial Group did not oppose (or specifically support) the Company's Grid Improvement Plan proposals in this case. (Commercial Group Stipulation at § 1.) The only caveat on this statement was an agreement that any GIP costs allocated to SGS-TOU customers would be recovered via demand charges. (Id. at § 2.)

CIGFUR Stipulation

On June 26, 2020, DEP and CIGFUR entered into the CIGFUR Stipulation resolving some of the issues in this proceeding between the two parties. The CIGFUR Stipulation provides, in relevant part, that for the purposes of settlement only and without taking a position on the appropriateness of the individual GIP programs or subprograms, CIGFUR supports the Company's request in this docket for approval to defer costs associated with the incremental GIP investments not included in this case and incurred over a three-year period for cost recovery consideration in future general rate cases. (CIGFUR Stipulation § III.A.) The CIGFUR Stipulation explains that because the three-year GIP contains estimates, CIGFUR's support for the GIP deferral will be subject to a reservation of its rights to review and object to the reasonableness of specific GIP program and subprogram costs in future rate cases. (Id.) The CIGFUR Stipulation also provides that to the extent that the Company enters into an agreement with other intervening parties agreeing to a cost cap or to otherwise limit the maximum allowed amount of the three-year GIP deferral, CIGFUR supports such cost containment measures. (Id.)

Additionally, the CIGFUR Stipulation provides that with regard to allocating the deferred GIP costs among the customer classes, in its next general rate case, the Company will propose to allocate these costs consistent with its distribution cost allocation methodologies as proposed in this Docket. (Id. at § III.B.) The CIGFUR Stipulation specifies that this includes use of the minimum system methodology and use of voltage differentiated allocation factors for distribution plant. (Id.) Moreover, the CIGFUR Stipulation states that assuming Commission approval, the Company agrees to use this methodology to allocate any GIP costs occurring during the three-year period for which it may seek cost recovery in future rate cases. (Id.)

Finally, the CIGFUR Stipulation states that for GIP costs incurred beyond the three-year period, nothing within the CIGFUR Stipulation shall be precedent for appropriateness of future deferrals or the allocation of deferred costs and these issues may be contested in future general rate case proceedings. (Id. at § III.C.)

Vote Solar Stipulation

On July 9, 2020, DEP and Vote Solar entered into the Vote Solar Stipulation resolving some of the issues in this proceeding between the two parties. The Vote Solar Stipulation provides, in relevant part, that Vote Solar supports the Company's request in this docket for approval to defer costs for investments in the ISOP, DSDR, SOG, DA, Transmission System Intelligence, DER Dispatch Tool, and the 44kV System Upgrade GIP programs and subprograms. (Vote Solar Stipulation, § III.1.) The Vote Solar Stipulation also provides that for all other GIP programs and subprograms, Vote Solar does not oppose the requested deferral accounting treatment. (Id.) The Vote Solar Stipulation further states that to the extent that the Company enters into an agreement with other intervening parties agreeing to a cost cap or to limit the amount of any GIP investment category specified for deferral treatment, Vote Solar supports such cost containment measures. (Id.) Finally, the Vote Solar Stipulation states that support for the GIP deferral will be subject to a reservation of its rights to review and object to the reasonableness of specific project costs in future rate cases. (Id. at § III.2.)

Additionally, the Vote Solar Stipulation provides that the Company commits to develop potential pilot customer programs prior to the submission of the 2022 IRP to optimize the capability of the GIP investments to support greater utilization of DERs, including but not limited to customer-sited solar and/or storage facilities (e.g., net metering successor), microgrid systems that benefit and would be paid for by specific benefitted customers, and programmable and load controllable devices or appliances for use in residential and non-residential demand response programs. (Id.) The Vote Solar Stipulation specifies that if the Company and Vote Solar mutually agree that these programs are cost-effective and meet appropriate Commission requirements, the Company agrees to file such pilot programs for approval by the Commission, and Vote Solar agrees to support such approval by the Commission. (Id.)

The NCSEA and NCJC et al. Stipulation

On July 23, 2020, DEP and an intervenor group consisting of NCSEA and NCJC et al. filed the NCSEA and NCJC et al. Stipulation with the Commission in this docket. In that settlement, the parties agreed that a number of DEP's proposed GIP programs would "directly enable and support the greater utilization of distributed energy resources on the Company's system." (NCSEA and NCJC et al. Stipulation at § III.) The programs that the parties to this settlement agreed to specifically support on this basis were as follows: (1) ISOP; (2) DSDR to CVR Conversion; (3) SOG; (4) Distribution Automation; (5) Transmission System Intelligence; (6) DER Dispatch Tool; and (7) 44kv Line Rebuild. (Id.) With regard to DEP's other then-pending GIP programs, the intervenor group agreed not to oppose the requested deferral treatment. The settlement with this intervenor group also reserved their right to review and object to the reasonableness of specific GIP costs in future rate proceedings. Finally, as part of the agreement, DEP agreed that congestion relief would be primary criterion in planning and decision-making regarding future transmission and distribution investments. (Id.)

Discussion of Intervenor Stipulations

The Commission finds that the Intervenor Stipulations, as they relate to the Company's GIP related proposals, are the product of arm's length negotiations between parties who took contradictory positions on this subject in the pre-filed testimony of this proceeding. The Commission notes that, at least with respect to the programs eligible for deferral treatment, the provisions of the Intervenor Stipulations are constrained by the provisions of the Second Partial Stipulation with the Public Staff which identifies eight GIP programs eligible for deferral treatment. The Intervenor Stipulations, in combination with the Second Partial Stipulation, dramatically reduce the number of contested issues presented to the Commission for resolution with regard to proposed GIP deferrals by effectively eliminating the disputes between the settling parties and DEP reflected in the testimony of the various intervenor witnesses related to DEP's GIP proposals. Several of the settlement stipulations with the environmental and social justice intervenors also indicate support for the GIP settlement based upon a belief that such settlements will promote and support the transition to DER and renewable energy resources.

The Commission concludes, based upon all the evidence presented in this case and discussed herein, that approval of the settlement stipulations entered into between DEP and the intervenors identified above with respect to an agreed resolution of the Company's proposed GIP deferral request represents a reasonable and negotiated resolution of the GIP disputes in this docket that is supported, or not opposed, by several of the parties filing testimony on GIP issues in this proceeding. Accordingly, the Intervenor Stipulations represent material evidence of the appropriate resolution of this proceeding relative to GIP-related issues and they will be treated as such by the Commission.

Consequences of Failure to Authorize GIP Deferrals

The Commission is mindful that a decision not to allow the settled GIP programs to proceed with deferral accounting has its own consequences. The evidence of those consequences, provided primarily by DEP witness Oliver, are effectively uncontested. That evidence is that without deferral accounting treatment, DEP will be unable to pursue critical grid modernization activities on a programmatic basis and instead will have to approach them on an ad hoc basis when funds can be obtained in competition with all other capital needs of the company. (Tr. vol. 5, 50-51; Tr. vol. 6, 57-58.) According to the evidence on this issue, this will significantly slow the implementation of grid modernization and make it less efficient whereas allowing deferral treatment for the settled GIP programs gives DEP "the ability to do the programs in a much more cost-effective way, do it in a planned-out way, to bring the benefits to our customers much sooner." (Tr. vol. 6, 56.). We agree with witness Oliver's testimony on this point and find that bringing the benefits of the eight settled GIP programs to customers sooner and with greater efficiency - rather than later with less efficiency - is in the public interest.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 69

The evidence supporting these findings and conclusions is contained in the Company's verified Application and Form E-1, the testimony and exhibits of DEP witnesses Hager and Oliver; Public Staff witnesses Thomas and McLawhorn, and the entire record in this proceeding.

Public Staff witness Thomas testified that there is no new allocation factor proposed for GIP investments, and all GIP costs are expected to be allocated among customer classes according to the allocation factors that have historically been used for transmission and distribution expenditures. (Tr. vol. 15, 485.) He stated that, at this time, he is not recommending that GIP costs be allocated differently than traditional transmission and distribution spend. (Id. at 486.) However, witness Thomas believes that the issue is ripe for Commission consideration, particularly in light of the Commission's order requiring the Company to file testimony in its next general rate case regarding the benefits that distributed generators are receiving from DEP's system, estimating their share of related costs, and providing options for recovering these costs from distributed generators.[10] (Id.) He testified that if the Commission agrees that this issue merits further study, DEP's planned study of the impact of distributed generation could be expanded to require an evaluation of possible alternative methods of allocating GIP investments that provide primarily reliability benefits. (Id.)

Public Staff witness McLawhorn testified that the Public Staff's analysis of GIP indicates that benefits derived from some of the assets are disproportionally related to the way the GIP transmission and distribution plant is allocated. (Id. at 926.) According to witness McLawhorn, distribution plant, for example, is heavily weighted toward the residential class, while the benefits derived from the GIP investments in distribution plant are heavily weighted toward the general service and industrial customer classes. (Id. at 926.) He testified that he believes this is an area of cost allocation that warrants further analysis and recommended that the Commission require DEP to study the allocation of

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[10] Order Approving Revised Interconnection Standard and Requiring Reports and Testimony, Docket No. E-100, Sub 101 (June 14, 2019).

GIP transmission and distribution investments/costs versus the benefits realized and report its findings to the Commission no later than the filing of its next general rate case. (Id. at 926-27.)

In her rebuttal testimony, Company witness Hager testified that the Company proposes that the investments associated with the GIP follow the same cost causation principles that are applied to the investments in the same FERC accounts as reflected in the cost of service study. (Tr. vol. 11, 1067.) She noted that while she has not looked at these costs in particular, it is her opinion that "attempting to allocate ANY investment costs for ratemaking purposes based on perceived benefits realized by customers, as differentiated from cost causation to the utility, is likely to be very subjective and thus controversial." (Id. at 1067-68.) She stated that one need look no further than witness Thomas's and witness Oliver's testimony to see that there are differing opinions on how to quantify customer benefits. (Id. at 1068.)

When asked by the Public Staff what the harm would be of a study that could resolve or result in a better understanding of the issue, witness Hager indicated that she does not believe it is an effort that is "likely to yield fruit." (Id. at 1178.) She said that the concept of allocating costs based on benefits has "so many downfalls" that to go forward with it would be a "waste of time." (Id.) She explained that while it is appropriate to look at the benefits in deciding which GIP projects to pursue and how to prioritize those projects (as the Company has done in its cost benefit analyses for GIP programs in this case), trying to allocate costs based on benefits is "very much a departure from traditional cost allocation methodologies." (*See* id. at 1179.)

> We don't look beyond the meter to say what benefits those customers receive. I think if you start doing that, I think there's a real question of, you know, where do you stop? How do you measure those benefits? I think we'd all agree what we've heard in this hearing is that there's [sic] a lot of different opinions on what those benefits would be. I would suggest they change frequently. I think [there] would be lots and lots of different arguments on how to quantify those.

(Id. at 1179-80.) For example, witness Hager noted that though reliability benefits can be most easily quantified for industrial and commercial customers, that does not mean there are not benefits for residential customers; rather, benefits to residential customers are just more difficult to quantify. (Id. at 1180.) She pointed out that cost benefit analyses only measure a narrow aspect of the benefits of GIP programs and concluded that "benefits are convenient for the purposes of selecting projects, but I would suggest that they really don't have a place for the purposes of cost of service." (Id.)

In response to questioning from counsel for CUCA, witness Hager reiterated that it would not be productive to spend a lot of time and effort exploring an alternative cost of service methodology that is based on allocating benefits. (Id. at 1206-07.) She stated that such an exercise would "depart from principles of cost causation" and "it's certainly not done within in the industry in any mainstream way." (Id. at 1207.) Moreover, she described benefits as “very individualized” and “very difficult to measure,” with any attempt to do so being “basically an estimate.” (Id.)

In response to Commission questions, witness Hager pointed out that if one were to take the Public Staff’s recommendation to “an extreme conclusion” and allocate all electricity costs based on benefits, “then you’ve completely upended the way that costs have been allocated in the past.” (Id. at 1278). She indicated that attempting to allocate costs based on benefits has the potential to create “artificial allocations based on things that are very, very difficult to quantify.” (Id.)

As noted in Evidence and Conclusions for Findings of Facts No. 62-63, the Company has agreed to propose, in a future rate case, that deferred GIP costs be allocated among the customer classes consistent with its distribution cost allocation methodologies as proposed in this docket, including minimum system. (CIGFUR Stipulation, § III.B.) In DEC’s last rate case, the Commission recognized that in light of substantial projected investment in grid modernization programs, “distribution system cost allocation among customer classes will take on heightened importance in future rate cases.” (*See* 2018 DEC Rate Order, at 85.) Accordingly, in the 2018 DEC Rate Order, the Commission directed the Public Staff to facilitate discussions with the electric utilities to evaluate and document a basis for continued use of minimum system and to identify specific changes, recommendations, and alternative approaches, if appropriate. (Id.) Witness Hager testified that in the resulting Report on Minimum System,[11] the Public Staff concluded that continued use of the minimum system method was reasonable for the electric utilities for the purpose of cost allocation and did not propose any alternative methodologies. (*See* Tr. vol. 11, 1250; *see also* Hager DEC Redirect Ex. 1, at 15-17.) In reaching this conclusion, the Public Staff reviewed the National Association of Regulatory Utility Commissioners “Electric Utility Cost Allocation Manual” published in January 1992 (NARUC Manual), which it stated “continues to be considered an important resource for the calculation and allocation of electric utility costs of service for regulatory commissions, consumer advocates, and parties before the Commission testifying on issues of cost of service and rate design.” (Tr. vol. 11, 1250-51; Hager DEC Redirect Ex. 1, at 4.)

Witness Hager acknowledged that the authors of the electric cost allocation manual published in January 2020 by the Regulatory Assistance Project (RAP)[12] – which presumably the Public Staff relies upon to make its recommendation relating to the study of allocating GIP costs based on benefits – suggest a different approach to aspects of cost of service allocation than the approach used in the NARUC Manual. (*See* Tr. vol. 11, 1177.) However, she explained that “the manual which is put out by the Regulatory Assistance Project comes from a very specific viewpoint of wanting to encourage energy

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[11] Report of the Public Staff on the Minimum System Methodology of North Carolina Electric Public Utilities, Docket No. E-100, Sub 162 (March 28, 2019). (Hager DEC Redirect Exhibit 1.) Note that in that Report, the Public Staff reserved the right to develop a new or different position concerning minimum system in a future proceeding. (Id. at fn. 25.)

[12] Electric Cost Allocation for a New Era (January 2020). (Public Staff Pirro/Hager Cross Examination Ex. 1.)

efficiency and distributed energy resources." (Id.) And therefore, the manual "favors policies and methods that would drive that." (Id.) She later noted that while RAP's dedication to a "clean, reliable, and efficient energy future" is certainly a laudable goal, it should not be captured in cost of service, which should be "focused on cost causation and how the electrons flow." (*See* id. at 1235.) She testified that cost of service "needs to avoid subjective aspects to the extent it can" and described it as "really more of a science." (Id. at 1216.)

Witness Hager compared the revenue requirement as being the size of the pie that the Company is seeking to recover and the cost of service study as how the pie is sliced. (*See* id. at 1201-1203.) In the cost of service world, witness Hager explained, "[e]veryone wants a smaller piece of the pie . . . give my slice to that person. I'll take a smaller slice." (Id. at 1203.) To that end, while intervenors have certain views as to how the pie is sliced based upon how a certain cost allocation methodology might benefit their constituents, the Company is essentially agnostic as to how the pie is sliced when it comes to cost allocation as long as it can recover all of its costs. (*See* id. at 1201-1203, 1299-1300.) Witness Hager agreed that the Company's primary motivation in proposing cost allocation methodologies is to allocate costs in a fair and equitable manner, according to longstanding cost allocation principles. (*See* id. at 1299-1300.) She explained that cost of service is supposed to be unbiased and is not intended to implement public policy: "I look at it as, you know, how do the electrons flow and what caused those electrons to flow in that manner." (*See* id. at 1202.) She concluded, "I think all things being equal…the Company is just trying to do what it believes is fair and equitable and treats essentially all electrons equally." (Id. at 1300.)

While the issue of how deferred GIP costs should be allocated got a fair amount to attention during the evidentiary hearing in this matter, the Commission need not address the appropriate cost allocation methodology in this case. The Commission will address recovery of deferred costs relating to GIP programs in the Company's next general rate case, and in that future rate case, the Commission will evaluate the Company's proposed allocation methodology, as well as any alternatives proposed by the Public Staff or other parties. Nevertheless, the Public Staff has asked the Commission to decide in this case that the Company should be required to study allocating costs relating to GIP investments based on benefits. The Commission gives great weight to the testimony of witness Hager that such an exercise would likely be highly subjective, imprecise, and controversial. As such, the Commission agrees with witness Hager that this type of study is not likely to be a productive or fruitful endeavor and therefore rejects the Public Staff's recommendation.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 70-71

The evidence supporting these findings and conclusion is contained in the Company's verified Application and Form E-1, the testimony and exhibits of Company witness Turner; Public Staff witness Metz; Sierra Club witness Wilson; NC WARN witness Powers, and the entire record in this proceeding.

In the Application, DEP stated that since its previous rate case it has made capital investments in its coal fleet to meet environmental regulations to allow for the continued operation of active coal units, and to add two 280-MW Asheville Combined Cycle (CC) units (Asheville CC Project), which feature technology for increased efficiency and will reduce carbon emissions across the Carolinas for customers' benefit. (Application at 4-5, 8.) The Company also introduced an updated depreciation study reflecting revised retirement dates for certain coal units in the DEP fleet, which it stated reflects the industry's shift toward earlier retirement of coal units to manage carbon footprint risk as well as changing economic conditions and environmental regulations. (Id. at 8.)

In her direct testimony, Company witness Turner described the Company's fossil/hydro/solar (FHO) generation assets and provided operational performance results for those assets during the Test Period. (Tr. vol. 11, 970-71, 975-77.) Witness Turner testified to the major FHO capital additions DEP has completed since the previous rate case, explaining that the Company has made significant investments in the coal fleet to meet environmental regulations to allow for the continued operation of active plants. (Id. at 972.) Witness Turner also discussed the addition of the Asheville CC Project units, and the retirement of the two Asheville Steam Electric Generating Plant units, anticipated by the end of 2019. In addition, she explained that the Asheville CC Project, for which DEP received a certificate of public convenience and necessity (CPCN) from the Commission in Docket No. E-2, Sub 1089 (Asheville CPCN Order), features state-of-the-art technology for increased efficiency and reduced emissions. (Id. at 971-72.) Witness Turner testified that the Company prudently incurred all of these costs, and addressed both the key drivers impacting O&M expenses during the Test Period and how DEP controls costs for capital projects and O&M. (Id. at 973-75.) Furthermore, she stated that these investments would be used and useful in providing electric service by the capital cutoff date, and benefit customers, as they have enabled DEP to continue to provide safe, efficient, and reliable service at least reasonable cost, and have reduced the Company's environmental footprint by adding state-of-the-art technology for reducing emissions, retiring older facilities that lacked environmental equipment and were not economically positioned for needed capital expenditures, and expanding the use of natural gas generation at a time when the natural gas market is providing low prices. (Id. at 973-74.)

In his direct testimony, Public Staff witness Metz discussed his review of DEP's capital additions to the FHO fleet, in which he looked at multiple aspects of capital spend to evaluate them for reasonableness and prudence, as well as whether the asset or result of the capital investment was used and useful. Witness Metz noted that his investigation included, in addition to reviewing prefiled direct testimony, an audit of specific expenditures, initial and follow-up discovery, teleconferences between and interviews with the Company and Public Staff, site visits, and review of the overall projects with Company management. (Tr. vol. 15, 821-22.) Witness Metz discussed the status of the Asheville CC Project and the repairs that had been required at one of the steam turbine components of that project, concluding that the Company was not at fault for the events necessitating the repairs. (Id. at 823-24.) The Public Staff did not recommend any disallowance of the Company's request for recovery of its capital investments in FHO based on imprudence. (Id. at 824.)

Sierra Club witness Wilson recommended disallowance of all of the Company's capital expenditures made during the time between the Sub 1142 case and the current case, based on her contention that the net value of each of the coal units was negative for the 2016-2018 time period, until DEP provides evidence of an analysis demonstrating the value of the investment done at the time the investment decision was made. In addition, she claimed that DEP did not demonstrate the prudence of its historical capital investments in its coal units. (Tr. vol. 15, 42-47, 54, 56.) Witness Wilson acknowledged the advancement of the probable retirement dates of certain units based on the Company's updated depreciation study. (Id. at 36-37). In addition, she acknowledged that retirement of the entire coal fleet at once would likely lead to reliability issues in DEP's service territory. (Id. at 50.) Based on her projected future energy value of the DEP coal fleet, and citing to the Georgia Public Service Commission (Georgia Commission) as having taken similar action, she also recommended that the Commission cap future capital expenditures intended to prolong the lives of these units and require DEP to obtain Commission approval of any expenditure that exceeds the cap before it can be recovered from customers. (Id. at 47-54.) Further, she recommended that the Commission disallow recovery of "ongoing" O&M expenses at DEP's coal units. (Id. at 57.) Witness Wilson also recommended that in future rate cases, DEP be required to demonstrate that its natural gas units are providing positive net value to ratepayers before being granted recovery of capital and O&M costs. (Id. at 50-54.) Finally, she suggested that the used and useful standard could be interpreted to mean that if there was a power plant construction project planned in a prudent manner, that operates at costs significantly higher than the economic value of the output for reasons beyond the utility's control and ability to reasonably foresee, the plant may be found prudent and used, but not economically useful. (Id. at 55.)

NC WARN witness Powers recommended disallowance of the Company's costs for the Asheville CC Project. (Tr. vol. 15, 885.) Witness Powers claimed that DEP's investments in this project were not reasonably and prudently incurred based on his contention that the project was not needed. (Id. at 886.) Specifically, he asserted that DEP could have avoided investing in the Asheville CC Project by relying on regional merchant combined cycle, hydroelectric plants, and the addition of battery storage at existing North Carolina solar facilities. (Id. at 882-885.) Finally, he compared his estimation of the production cost at the Asheville CC Project to approximations of production costs for hydroelectric and battery storage resources. (Id. at 881-84.)

In her rebuttal testimony, witness Turner responded to the testimony and recommendations of witnesses Wilson and Powers. Witness Turner also described the voluminous information that DEP provided through discovery in this case, in addition to the evidence presented in her direct and rebuttal testimonies. (Tr. vol. 11, 989-991.) Addressing arguments concerning the economic value of the coal fleet, she explained that such contentions fail to recognize the full picture of how DEP dispatches its coal fleet to maximize value for customers. Witness Turner noted that witness Wilson's study did not appear to account for the requirement of day-ahead planning reserves, and explained that capacity must be online or available within 10 minutes. Further, she stated that a coal unit will provide energy and capacity during the peak, and that if a needed coal unit is not online then the Company must start additional combustion turbines and/or purchase energy and capacity from the market, if capacity was available during such a time. (Id. at 991-92.)

Witness Turner also testified that witness Wilson's forward-looking analysis of the coal fleet is not a valid exercise for a general base rate case. (Id. at 992.) Witness Turner noted that witness Wilson did not explain how her proposed cap on future coal fleet investments would be determined, and clarified that these investments were not made to "prolong" the life of particular units but rather to maximize their remaining useful life. Witness Turner stated that the Company cannot recover such costs—or O&M costs or costs for investments in DEP's natural gas units—from customers unless and until the Commission permits it to do so. Finally, she clarified that estimates of future capital investments are not relevant to this proceeding. (Id. at 992-93.)

In response to witness Powers' suggestion that the Company could provide reliable electric service without the continued availability of its coal fleet through purchased power and renewable resources, witness Turner testified that he did not offer a credible and specific explanation of how DEP could have replaced the reliable generation provided by the Asheville CC Project, and did not otherwise credibly challenge the Company's reasonable and prudent decision to invest in this project. In addition, she noted that NC WARN ignored additional factors that support the reasonableness and prudence of this investment, including the Mountain Energy Act, which specifically contemplates DEP's construction of a new natural gas fired generating facility at the Asheville site, and the Commission's determination in the Asheville CPCN Order that the project was needed. (Id. at 994-95.)

At the hearing, in response to questioning by Sierra Club counsel, witness Turner explained that DEP did not conduct a comprehensive retirement analysis regarding investment in environmental compliance projects at Roxboro Station, but did a similar analysis for Mayo Station, which indicated in all scenarios studied that it was not economical for customers to retire Mayo Station early rather than make the environmental investments. Because early retirement would not be economical for Mayo Station, which has a 700 MW capacity, she explained that it also therefore would not be economical for Roxboro Station, with a capacity of 2400 MW. Witness Turner stated in addition that the energy produced by these stations was required for DEP to reliably serve its customers, and that DEP could not have replaced these resources in the period of time available. (Id. at 1002-03, 1005.) Witness Turner also explained that each of the scenarios evaluated in the Mayo study considered natural gas as the alternative, because natural gas was determined to be the most economical type of generation resource as shown in the Company's most recent IRP at that time. (Id. at 1003-04.)

During redirect examination, witness Turner clarified that the portion of total investments DEP made at Roxboro and Mayo Stations related to environmental compliance exceeded the portion for maintenance capital investments at those stations. (Id. at 1006-07.) In addition, she confirmed that the Company would have had to make approximately half of the environmental investments even if it retired these units early, in order to remain compliant with environmental regulations. (Id. at 1007.) Witness Turner also described the disciplined process DEP uses to evaluate whether to make investments in its coal fleet, including economic analyses of potential investments, and confirmed that the Company operates and makes investment decisions based on information available at the time. Witness Turner also described how the Company's investments in its coal fleet have benefitted customers, explaining for example that while capacity factors for the coal fleet have declined in recent years, these units' capacity is critical to the DEP system as evidenced by the 94% capacity factor at the Roxboro and Mayo units during early January 2018. Witness Turner confirmed that DEP's coal fleet investments have allowed the Company to remain environmentally compliant and to continue to provide safe and reliable service to customers. (Id. at 1008-10.) She testified that the updated plans for DEP's coal fleet presented in the Company's 2020 IRP are consistent with its proposal in this case to accelerate the depreciable lives of some of those units. (Id. at 1010-11.)

In response to questions from counsel for the Company, witness Wilson agreed that as DEP transitions away from reliance on coal, it must do so while continuing to meet its obligation to provide safe and reliable electric service to customers. (Tr. vol. 15 at 65.) Witness Wilson acknowledged that her testimony did not specify any particular project or costs that DEP should not have incurred, did not offer other options that DEP could have chosen instead of incurring any of the costs it seeks to recover now, and that her analysis did not analyze the Company's decisions about coal fleet investments at the time it made those decisions. (Id. at 98-99.) Witness Wilson testified that she was not aware of the North Carolina standard for challenging prudence that requires a party to identify specific instances of imprudence and provide a prudent alternative. (Id. at 68.) With regard to her testimony on the "used and useful" standard, she could not identify any state commission that had adopted her interpretation of that standard. (Id. at 72.)

Witness Wilson agreed that some of the coal fleet environmental investments were required whether or not the units continued to operate, and that if additional environmental projects in order to continue to run those units had not been made, DEP would have had to shut the units down. (Id. at 76-77.) Witness Wilson testified that she did not analyze whether shutting the units down was a feasible path DEP could have chosen and continued to meet its service obligations. (Id. at 77-78.) When asked to illustrate her testimony that retiring all of the units immediately would likely result in reliability issues, she stated that "the lights … could potentially go out," and noted that retiring all of the coal units would not be sufficient to meet peak load plus a required reserve margin. (Id. at 78.)

Witness Wilson acknowledged that North Carolina uses a historical test year, updated through a certain time period, to examine reasonableness and prudency of costs. (Id. at 73.) With regard to the case she cited in support for her future investment cap proposal, she agreed that the Sierra Club did not join the stipulation approved by the Georgia Commission, and that non-signing parties' recommendations in that case were specifically denied. (Id. at 74-75.)

Witness Wilson agreed that the 2016 Mayo Station retirement study evaluated the costs and benefits of retiring those units earlier than was planned at the time. Witness Wilson acknowledged that she did not do an analysis of whether it would have been feasible or cost-effective for DEP to retire Mayo or Roxboro Stations rather than make the investments the Company is seeking to recover in this case. (Id. at 103.)

In response to questioning by Commissioner Hughes regarding how to reconcile her testimony that retirement of the entire coal fleet would lead to reliability issues with her recommendation to categorically exclude all costs of the coal fleet, witness Wilson testified that her recommendation was to exclude the capital costs until the Company could provide economic analysis showing that the units were cost effective for customers. (Id. at 94.)

Discussion and Conclusions

Based on the entire record in this proceeding, the Commission finds and concludes that the costs associated with the Company's investments in its coal fleet were reasonably and prudently incurred and should be recovered. The Commission further finds and concludes that Sierra Club's additional recommendations to limit the Company's future investments in its coal and natural gas units should not be adopted.

When setting just and reasonable rates, the Commission must determine whether costs incurred by the utility were prudently incurred, which involves an examination of whether the utility's actions, inactions, or decisions to incur costs were reasonable based on what it knew or should have known at the time the actions, inactions, or decision to incur costs were made. DENC Order at 121; Harris Order at 14 (if needed: Order Granting Partial Increase in Rates and Charges, *Application by Carolina Power & Light Company for Authority to Adjust and Increase Its Rates and Charges*, No. E-2, Sub 537, at 14 (N.C.U.C. Aug. 5, 1988), *rev'd in part on other grounds and remanded*, *Utils. Comm'n v. Thornburg*, 325 N.C. 484, 385 S.E.2d 463 (1989) (Harris Order)). Challenging prudence requires a detailed and fact intensive analysis, and the challenger is required to (1) identify specific and discrete instances of imprudence; (2) demonstrate the existence of prudent alternatives; and (3) quantify the effects by calculating imprudently incurred costs. DENC Order at 121-122; Harris Order at 14-15.

The burden of proof to show that rates are just and reasonable is on the utility. N.C.G.S. § 62-134(c). Nevertheless, intervenors have a burden of production in the event that they dispute an aspect of the utility's prima facie case. *State ex rel. Utils. Comm'n. Intervenor Residents of Bent Creek/Mt. Carmel Subdivisions*, 305 N.C. 62, 76, 286 S.E.2d 770, 779 (1982) (*Intervenor Residents*) ("The burden of going forward with evidence of reasonableness and justness arises only when the Commission requires it or affirmative evidence is offered by a party to the proceeding that challenges the reasonableness of expenses . . . ."). If the intervenor meets its burden of production through the presentation of competent, material evidence, then the ultimate burden of persuasion reverts to the utility, in accordance with N.C.G.S. § 62-134(c).

The Commission gives substantial weight regarding the prudency of the costs of DEP's investments in its coal fleet to the prefiled and hearing testimony of Company witness Turner. Witness Turner explained in detail how the Company prudently determined that these investments were needed to maintain DEP's remaining active coal units in order to continue to provide safe, reliable, and cost-effective electric service to customers. A significant portion of these costs were required under environmental law or regulation regardless of whether the Company continued to run the units. A large portion of the remaining costs were incurred to maintain compliance with environmental requirements in order to continue to operate the units, and no party has offered concrete, specific evidence to contradict DEP's determination that it needed to continue to operate these units to serve customers. With regard to the Asheville CC Project, witness Turner presented convincing evidence in rebuttal and at the hearing regarding the rationale for this investment, which was made pursuant to the Mountain Energy Act and which the Commission found was needed in Docket No. E-2, Sub 1089. As addressed in Evidence and Conclusions for Finding of Fact No. 11, the Asheville CC Project is complete, placed in service, and available for economic dispatch.

No intervenor has met the burden of production to challenge the Company's coal fleet investments. Sierra Club witness Wilson's recommended disallowance, as she admitted, is not specific to any particular cost, nor does Sierra Club offer any prudent alternative that DEP could have chosen rather than to make these investments. Witness Wilson in fact testified that retiring the coal fleet all at once would likely result in reliability issues, but did not identify any other alternatives available to the Company. Regarding NC WARN's recommendation, other than the Asheville CC Project in general, witness Powers does not identify specific costs as being imprudently incurred. In addition, the alternatives suggested by NC WARN—merchant generation purchases, solar plus storage, and hydroelectric generation—are not supported by any evidence suggesting these were feasible options for the Company. No witness conducted an independent analysis using the information available at the time the Company's investment decisions were made to present evidence supporting a finding that DEP could have made another prudent choice. The evidence demonstrates that the Company made the best investment decisions it could with the information available at the time. The evidence also supports our conclusion that DEP is making needed investments to maximize the remaining useful life of its coal fleet, at the same time as it is moving away from relying on coal, as evidenced by its request in this case to reduce the depreciable lives of certain units. The Commission agrees that as DEP transitions away from coal, it must do so in a manner that allows it to continue to reliably serve customers, and concludes that these investments were made consistent with that service obligation.

Moreover, the Commission finds persuasive witness Turner's rebuttal of witness Wilson's economic value analysis, which did not consider either the capacity value provided by DEP's coal fleet or how the Company dispatches its system as a whole on a daily basis. Isolating costs invested in and the value of energy produced by a particular station on an annual basis does not accurately represent the value of the coal fleet; as witness Turner showed, even units with declining capacity factors are needed during times of high demand. Finally, the Commission does not accept witness Wilson's interpretation of the term "useful" in the used and useful standard. Her reading contemplates finding an asset not to be useful when it was planned prudently and was impacted by changes outside the utility's control, which is not an interpretation that has been adopted by this Commission. On the contrary, if an expenditure does support and provide service to customers, those costs are "used and useful." Sub 1146 Order at 259.

Finally, witness Wilson qualified her disallowance recommendation on the contention that DEP did not present evidence of the value of the investments at the time they were made. However, as witness Wilson's hearing testimony made clear, she ignored evidence in the form of the 2016 Mayo Station retirement study pertaining directly to this issue. As shown by witness Turner's prefiled and live testimony, including her testimony regarding the volume of data DEP provided to the Public Staff and intervenors in support of coal fleet investments, the Company conducted an exhaustive study of continued investments in Mayo Station, as well as economic analyses of other coal fleet investments, and relied on the results of those studies to proceed with the investments it is seeking to recover. The Commission therefore concludes that Sierra Club's contention regarding a lack of evidence is unfounded, as DEP has demonstrated the reasonableness and prudence of incurring these costs and, as discussed above, no party has presented concrete evidence otherwise.

The Commission also declines to accept witness Wilson's recommendations regarding the Company's future investments in its coal and natural gas units. Her proposed limit on capital investments in the coal fleet and other recommendations regarding future recovery are not necessary, as the Company cannot recover any future investments before seeking and obtaining the Commission's approval in a future proceeding. Further, witness Wilson offered no evidence regarding the prudence of DEP's investments in its natural gas fleet. Finally, as witness Wilson recognized, North Carolina uses a historical test year as the basis for evaluating just and reasonable rates, which is not consistent with a prospective limit on capital expenditures.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 72

The evidence supporting this finding and conclusion is contained in the Company's verified Application and Form E-1, the testimony and exhibits of DEP witness Henderson, Public Staff witness Metz, and the entire record in this proceeding.

In his direct testimony, Company witness Henderson described DEP's nuclear generation assets and capital additions to the nuclear fleet made to enhance safety, address regulatory requirements, and preserve performance and reliability of these plants throughout their extended life operations. (Tr. vol. 11, 127-32.) Witness Henderson testified that these capital additions and enhancements are used and useful in safely and efficiently providing reliable service to DEP customers and position the Company to maintain the high levels of operational safety, efficiency and reliability reflected in the fleet's performance results. (Id. at 132.) Witness Henderson also discussed key drivers impacting nuclear O&M costs, including inflationary pressure on labor and materials, and the Company's strategy for mitigating that pressure. Witness Henderson also testified to how the Company controls for capital projects and O&M using a rigorous cost management program and through outage optimization. Witness Henderson noted that customers will continue to benefit from the strong performance of DEP's nuclear fleet through lower fuel costs. (Id. at 132-34.) Witness Henderson described DEP's current status with respect to compliance with Nuclear Regulatory Commission (NRC) requirements. (Id. at 135-39.) Finally, he discussed the high performance of the Company's nuclear fleet during the Test Period and the steps DEP has taken to increase efficiencies in nuclear operations. (Id. at 139-42.)

Public Staff witness Metz testified regarding his review of DEP's capital additions to the nuclear fleet, in which he looked at multiple aspects of capital spend to evaluate them for reasonableness and prudence, as well as whether the asset or result of the capital investment is used and useful. Witness Metz noted that his investigation included, in addition to reviewing witness Henderson's prefiled direct testimony, an audit of specific expenditures, initial and follow-up discovery, teleconferences between and interviews with the Company and Public Staff, including detailed discussions on specific aspects of certain projects, and review of the overall projects with Company management. (Tr. vol. 15, 821-22.)

No party recommended any disallowance of the Company's request for recovery of its capital investments in its nuclear fleet based on unreasonableness or imprudence.

Based on the foregoing, the Commission finds and concludes that the costs associated with the Company's investments in its nuclear generating fleet were reasonably and prudently incurred and should be recovered.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 73

The evidence supporting this finding and conclusion is contained in the verified Application and Form E-1 of DEP, the testimony and exhibits of DEP witnesses De May and Spanos; Public Staff witnesses McCullar, Dorgan, Metz and Maness; FPWC witness Brunault, and the entire record in this proceeding.

Company witness Spanos introduced Spanos Ex. 1, the depreciation study filed in this docket (Depreciation Study) prepared by Gannett Fleming Valuation and Rate Consultants, LLC. (Tr. vol. 11, 210-11.) As explained by witness Spanos, the Depreciation Study included updates to estimates of final plant depreciation costs for steam, hydraulic, and other production plants, as well as updated forecasted generation plant retirement dates. In addition, witness Spanos noted that the Depreciation Study incorporates the full decommissioning cost values from the previously performed Burns and McDonnell decommissioning studies. These decommissioning studies included estimates for final decommissioning costs at steam, hydraulic, and other production plants.

The updated depreciation rates for various fossil and hydro plants reflect changes in the probable retirement dates, capital additions, component replacements, and full consideration of all decommissioning study costs (Spanos Ex. 1 at iii.) As witness Spanos explained, estimates for costs related to coal ash pond closures are not included in the net salvage estimates, and therefore not included in depreciation rates. (Tr. vol. 16, 309-10.)

Public Staff witness McCullar also made recommendations related to depreciation expense. Witness McCullar recommended several adjustments to the Company's proposed depreciation rates including adjustments to future terminal net salvage costs (also known as decommissioning and dismantlement costs). Witness McCullar also recommended a longer average service life for AMI meters, different net salvage percentages for three mass property distribution accounts, and proposed adjustments to the amortization periods for two general plant accounts. (Tr. vol. 15, 791-92, 806.) Finally, at the direction of the Public Staff, witness McCullar calculated depreciation rates using the retirement dates for the Mayo 1 and Roxboro 3 and 4 units from the previous depreciation study in Docket No. E-2, Sub 1142. (Tr. vol. 15, 806.)

The Commission's discussion and resolution of issues raised by witnesses McCullar, Dorgan, Metz, Maness and Brunault are discussed below.

Estimated Terminal Net Salvage Costs

Burns & McDonnell conducted the Decommissioning Study for DEP in 2017, which formed the basis for DEP's terminal net salvage cost estimates. Witness McCullar proposes that this Commission continue the use of the 10% contingency for future "unknowns" approved in Docket No. E-2, Sub 1142. (Id. at 789.) In response to witness McCullar's recommendation, witness Spanos explained why a 20% contingency is appropriately included in DEP's Decommissioning Study and why it is necessary that costs must be escalated to the date of retirement. (Tr. vol. 16, 283-96.)

The Need for Contingency

The Company's Decommissioning Study included a 20% contingency to cover unknowns. As Company witness Kopp testified in Docket No. E-2, Sub 1142, contingency costs are necessarily included in the Decommissioning Study to account for unspecified but reasonably expected additional costs to be incurred by the Company during the execution of decommissioning and demolition activities. (2018 DEP Rate Order, at. 43.) Furthermore, past experience with costs incurred in the Carolinas by the Company for the decommissioning and demolition of the Cape Fear, H.F. Lee, Sutton, Robinson, and Weatherspoon plants were approximately 11% higher than the Burns & McDonnell estimates, inclusive of contingency. (Id.) Such past experience demonstrates the importance of contingency to the decommissioning cost estimate.

Public Staff witness McCullar recommended continued use of a 10% contingency factor, as approved by the Commission in Docket No. E-2, Sub 1142. (Tr. vol. 15, 789.)

In his rebuttal testimony, witness Spanos testified that "the terminal net salvage estimates I have used in the calculation of depreciation rates are based on a comprehensive decommissioning study performed by Burns and McDonnell. The decommissioning study incorporates a 20% contingency and this study, as well as DE Progress witness Kopp's testimony in DE Progress' previous case, provide the justification for this contingency factor. Additionally, . . . the context of other proposals in this case and the fact that coal ash costs show that end of life costs can be higher than originally anticipated provide additional support for the need for contingency." (Tr. vol. 16, 295-96.)

The intent of adding the contingency is to ensure that decommissioning activity is fully funded at the point of retirement. Furthermore, the Decommissioning Study does not, and cannot, assume that some intervening event will avoid the future cost of decommissioning. Regardless, there are substantial costs required to shut down a facility whether or not demolition occurs, and contingency is a necessary component of those costs. Finally, the 20% contingency recommendation is consistent with other studies that Burns & McDonnell prepared for utility clients across the United States including Duke Energy affiliate companies, several of which have been approved by other Utility Commissions.

In the Company's last general rate case, the Commission approved a 10% contingency factor. (2018 DEP Rate Order at 44.) There, witness McCullar recommended a 0% contingency. (Id. at 43.) The evidence presented by the Company in that case established the importance and necessity of including contingency. Further, even with a 20% contingency there remains risk that the cost incurred by DEP for decommissioning and demolition may actually run higher than the Burns & McDonnell estimate inclusive of contingency.

In light of all of the evidence, the Commission finds and concludes that the 20% contingency factor proposed by the Company is just and reasonable and appropriate for use in this case. Contingency represents a real cost that is anticipated to be incurred on the project and using 20% will help increase the likelihood that decommissioning activity will be fully funded at the point of retirement.

Cost Escalated to the Date of Retirement

It is important to recover the service value of the Company's assets by determining the net salvage costs that will be incurred in the future. As DEP witness Spanos explained, using the straight-line method of depreciation, these costs are recovered ratably, or in equal amounts, each year over the life of the Company's plant. (Tr. vol. 16, 251.) This approach is consistent with the Federal Energy Regulatory Commission Uniform System of Accounts (USOA), which specifies that the cost of removal is the actual amount paid at the time the transaction takes place. (Id. at 187.) As such, including the future cost of net salvage for plant accounts is consistent with established depreciation concepts. (*See* 2018 DEC Rate Order, at 173.) In developing decommissioning cost estimates, it is necessary to escalate these amounts to the time period in which the cost is expected to be incurred. (2018 DEC Rate Order, at 173.)

Witness McCullar calculated net salvage estimates for production plant accounts escalated to the date of final retirement, consistent with the 2018 DEP Rate Order. (Tr. vol. 16, 285.)

As explained by witness Spanos, the Commission reviewed this concept in Docket No. E-7, Sub 1146 and determined that “the escalation of terminal net salvage cost and the use of the straight-line method of depreciation in determining escalation as performed in the DEC Decommissioning Study is just and reasonable, appropriate for use in this case, and is adopted.” (2018 DEC Rate Order, at 175; Tr. vol. 16, 284.) The Commission also concluded that estimating net salvage as the future cost to retire an asset is consistent with sound depreciation practices and authoritative texts. (2018 DEC Rate Order, at 174; Tr. vol. 16, 284.) Specifically, the Commission cited the National Association of Regulatory Utility Commissioners’ *Public Utility Depreciation Practices* for the principle that “[n]et salvage is the difference between gross salvage that will be realized when the asset is disposed of and the costs of retiring it.” (2018 DEC Rate Order, at 174; Tr. vol. 16, 284-85.) The Commission also cited Wolf and Fitch, another highly regarded authoritative depreciation text, for the position that inflation is appropriately a part of the future cost of net salvage. (2018 DEC Rate Order, at 174; Tr. vol. 16, 292.) In his testimony, witness Spanos provided the following passage from Wolf and Fitch:

> The matching principle specifies that all cost incurred to produce a service should be matched against the revenue produced. Estimated future costs of retiring an asset currently in service must be accrued and allocated as part of the current expenses.

(Id.) Wolf and Fitch also make clear that inflation is part of the future cost of net salvage. Witness Spanos pointed out that Wolf and Fitch state the following:

> Negative salvage is a common occurrence. With inflation, the cost of retiring long-lived property, such as a water main, may exceed the original installed cost.

(Id.) Additionally, with respect to intergenerational equity, witness Spanos noted that Wolf and Fitch state that:

> The accounting treatment of these future costs is clear. They are part of the current cost of using the asset and must be matched against revenue. While the current consumers would say they should not pay for future costs, it would be unfair to the future users if these costs were postponed.

(Id.) Finally, Wolf and Fitch also argue against a present value or current value concept. Witness Spanos provided the following excerpt from Wolf and Fitch:

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

(Id. at 292-93.) Accordingly, Commission precedent, authoritative texts, and sound depreciation practices all support escalating terminal net salvage costs to the date the costs are expected to be incurred rather than some artificially foreshortened date.

While witness McCullar claims five other jurisdictions removed the escalation of estimated future terminal net salvage costs, none of the cases witness McCullar cited change the fact that the Commission has already decided this issue in Docket No. E-7, Sub 1146. (Id. at 287-88.) As witness Spanos explained, of the five cases witness McCullar cites, two do not even apply net salvage calculations in the manner she suggests and the remaining three do not change the fact that the manner in which DEP has calculated net salvage is the predominant approved methodology utilized in depreciation studies approved throughout the United States. (Id.) In Docket No. E-7, Sub 1146, the Commission found that the Company's approach to net salvage is used by the vast majority of regulatory jurisdictions. (Id. at 288; 2018 DEC Rate Order, at 175.) Specifically, the Commission stated that:

> The fact is the vast majority of jurisdictions use a method for net salvage in which future net salvage is estimated at its future cost and recovered through straight-line depreciation (also known as the traditional method). Approximately 46 out of 50 jurisdictions recover future costs using the straight-line depreciation method.

(2018 DEC Rate Order, at 175; Tr. vol. 16, 288.) North Carolina is one of those jurisdictions that use the traditional method. Because of this fact, the Commission concludes that the cases witness McCullar cites are in the minority and should not be afforded any weight in this proceeding. (Tr. vol. 16, 289.)

Finally, the Commission previously found witness McCullar's approach to estimating terminal net salvage to be deficient. (Id. at 286.) In the 2018 DEC Rate Order, witness McCullar challenged the inclusion of the full future net salvage cost in depreciation and instead proposed to include only estimates of net salvage costs at current cost levels. (Id. at 284.) The Commission already reviewed this concept in Docket No. E-7, Sub 1146 and did not find witness McCullar's arguments persuasive. In the 2018 DEC Rate Order, the Commission stated the following:

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

supported by authoritative accounting literature, and supported by unwarranted assumptions.

(2018 DEC Rate Order, at 175 (footnotes omitted); Tr. vol. 16, 286.)

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

Mass Property Future Net Salvage

Net salvage estimates are expressed as a percentage of the original cost retired. (Id. at 286.) The method for determining the estimated net salvage percent depends on the type of property. (Id.) For power plants, the estimate is typically based on a decommissioning study, with additional net salvage incorporated for interim retirements. (Id. at 286-87) For mass property accounts such as those for transmission and distribution plant, net salvage estimates are based in part on statistical analyses of historical net salvage data. (Id. at 287) In this case, the statistical net salvage analyses incorporate the Company's actual historical data from 1979 through 2018, and considers the cost of removal and gross salvage ratios to the associated retirements during the 40-year period. (Tr. vol. 16, 249.)

Witness Spanos, in his depreciation study, recommends a net salvage percentage of negative 100% for Account 364, Poles, Towers and Fixtures, negative 15% for Account 366, Underground Conduit, and negative 20% for Account 369, Services. Witness McCullar recommends a future net salvage percent of negative 75% for Account 364, negative 10% for Account 366, and negative 15% for Account 369. (Tr. vol. 15, 792.) Witness McCullar expressed concern with the Company's historic net salvage ratios calculated in the Depreciation Study. (Id. at 794-95.) Specifically, witness McCullar took issue with using a net salvage ratio that includes inflated dollars in the numerator and historic dollars in the denominator. (Id.) Witness McCullar explained that due to inflation, the amounts in the numerator and denominator of the net salvage ratio are at different price levels. (Id. at 795.) Witness McCullar noted that five other jurisdictions have adopted future net salvage percentages that recognized the inflated dollars included in the historic net salvage ratio and adopted future net salvage percentages that recognize the time value of cost of removal due to inflation. (Tr. vol. 16, 287-88.)

In response, witness Spanos testified that witness McCullar's proposal is not consistent with the Commission's decision in Docket No. E-7, Sub 1146 and is unsupported by the record. (Tr. vol. 16, 286.) Witness McCullar supports her treatment of Accounts 364, 366, and 369 by arguing against including future inflation in net salvage estimates. (Id. at 285.) Witness McCullar did not provide any statistical basis for her proposal other than recently recorded costs. (Id.) Witness McCullar also noted that five other jurisdictions have removed the escalation of estimated future terminal net salvage costs. (Tr. vol. 15, 795-98.) As witness Spanos previously testified, the Commission has already decided against witness McCullar's position on this concept and found that the

Company's approach was widely supported. (Id.) Overall, while witness McCullar's proposals for these accounts does not have as significant an impact as her proposals for other accounts, she does not provide any statistical basis for her proposal. (Id.) The only analytical method witness McCullar provides in support of her proposal is a comparison of the net salvage costs included in the proposed depreciation rates to the amount of net salvage DEC has incurred, on average, over the past five years. (Id. at 294.) This type of analysis performed by witness McCullar does not provide a reasonable basis to estimate net salvage. (Id. at 294-95.) Additionally, NARUC and Wolf and Fitch do not support witness McCullar's approach for mass property accounts. (Id. at 293-94.) In fact, the Company is unaware of any authoritative texts that support witness McCullar's analysis. (Id. at 295.)

Witness Spanos was also asked on cross-examination about the net salvage calculation in an Atmos Energy rate proceeding in Kansas in which witness McCullar testified. (Public Staff Spanos Cross-Examination Ex. 3.) This testimony did not undermine witness Spanos' position on net salvage, however, because it was clear from the face of the order in that proceeding that the Kansas Commission explicitly rejected a proposed negative salvage calculation based on a "recent history" approach similar to that offered by witness McCullar in this case. (Id. at ¶54.)

Considering all of the evidence, the Commission finds and concludes that the Company's proposed future net salvage rates for mass property Accounts 364, 366, and 369 are just and reasonable, appropriate for use in this case, and are adopted.

15-Year Service Life for AMI Meters

DEP requested a 15-year depreciation life for AMI meters. As explained by witness Spanos, a 15-S2.5 survivor curve was recommended by DEC for AMI meters, which the Commission previously approved in Docket No. E-7, Sub 1146. (Tr. vol. 16 at 297.) This estimate was consistent with the manufacturer's recommendation for the physical life of the AMI meters and accounted for alternative reasons for retirement such as damage or obsolescence. (Id.)

Public Staff witness McCullar recommended a 17-year service life for AMI meters. (Tr. vol. 15, 792.) Witness McCullar testified that a 17-year life is in the middle of the manufacturer's range, is a reasonable estimate based on the manufacturer's expected life of the AMI meters, and is fair to the Company and the ratepayer. (Id. at 791-92.)

In response, witness Spanos pointed out that the Commission approved the 15-year service life for AMI meters in the 2018 DEC Rate Order. (Tr. vol. 16, 296-98.) DEP used a 15-year average service life in its previous depreciation study in Docket No. E-2, Sub 1142. (Id. at 296.)[13] The 2018 DEC Rate Order adopted the depreciation rates proposed by DEC, except for certain depreciation rates discussed in the decision. As witness Spanos explained, because the 15-year average service life was not specifically identified and modified in the 2018 DEC Rate Order, the 15-year average service life was adopted by the Commission. (Id. at 297.) Moreover, DEC's cost-benefit analysis for AMI meters was based on a 15-year average service life and the Commission had specifically requested that such analysis include the "cost of replacing AMI meters at the end of their 15-year useful life." (2018 DEC Rate Order, at 117; Tr. vol. 16, 297.)

Witness McCullar has not provided any new evidence in the instant case that supports changing the 15-year average service life approved by the Commission. Witness Spanos noted that witness McCullar's arguments are almost identical to those she presented in Docket No. E-7, Sub 1146 that were not adopted by the Commission. (Tr. vol. 16, 298.) Additionally, witness McCullar simply took the mid-range of the manufacturer's life without considering issues like technological obsolescence. In that regard, witness McCullar made no attempt to distinguish the type of asset, which is a critical consideration when there is limited historical experience.

In light of all the evidence, the Commission finds and concludes that the Company's request to establish a 15-year average service life for AMI meters is just and reasonable and appropriate for use in this case.

Life Spans of Mayo Unit 1 and Roxboro Units 3 and 4

Since the last depreciation study, DEP has changed the life spans of Mayo Unit 1 and Roxboro Units 3 and 4 to be shorter than currently approved. DEP witness De May explained that "[a]s part of our strategy to reduce our reliance on coal, we have taken a fresh look at the viability of several of our coal-fired plants and have concluded that making shifts in the expected remaining depreciable lives of some of our coal-fired assets is a reasonable action to take now, while we continue to monitor the changing industry landscape and impacts of markets forces." (Tr. vol. 11, 755.) As witness Spanos testified, DEP intends to retire each of these units in 2029. (Tr. vol. 16, 301.) Witness Spanos incorporated the shortened life spans for these units into the Depreciation Study and recommended depreciation rates using these retirement dates. (Id. at 299.) As explained by witness Spanos, the revised life spans are reasonable because, in recent years, original life spans for steam production facilities have been shortened due to unit efficiencies and operating costs (driven in part by environmental regulations). (Id. at 299.)

Public Staff witness McCullar calculated depreciation rates using the retirement dates from the previous depreciation study. (Tr. vol. 16, 806.) Witness McCullar explained

[13] The Docket No. E-2, Sub 1142 depreciation rates for AMI meters were ultimately settled with the Public Staff using a different useful life calculation than was decided by the Commission in the Docket No. E-7, Sub 1146 proceeding.

that Public Staff directed McCullar to use the original retirement dates for Mayo Unit 1 and Roxboro Units 3 and 4. (Id.)

Public Staff witness Dorgan recommended that witness McCullar restore the depreciation rate of Mayo Unit 1 and Roxboro Units 3 and 4 to the depreciation rate approved in Docket No. E-2, Sub 1142 for several reasons. (Tr. vol. 15, 734.) First, witness Dorgan noted that although DEP stated that it intends to retire the Mayo 1 and Roxboro 3 and 4 Units, it has not done so. (Id.) Second, Public Staff has consistently recommended that depreciation rates be set at the original retirement date of the plant. (Id.) Thereafter, at the physical date of retirement, any remaining net book value is placed into a regulatory asset account and amortized over a reasonable period, to be determined in a future general rate case. (Id.) Third, witness Dorgan cites witness Metz's operational concerns with the accelerated retirement of these generating units. (Id.)

Additionally, Public Staff witness Metz took issue with evaluating the early retirements of Mayo Unit 1 and Roxboro Units 3 and 4 in the current proceeding. While witness Metz did not dispute the accelerated retirements of the units, he recommended that the retirements of these units be reviewed in DEP's Integrated Resource Plan (IRP) proceeding. (Tr. vol. 15, 832.) Witness Metz acknowledged that the IRP does not solely focus on the economics of early generation retirements but nonetheless suggested that it was a more appropriate forum to evaluate early retirements than a general rate case. (Id.)

FPWC witness Brunault also argued for extending the recovery of capital costs associated with Mayo Unit 1 and Roxboro Units 3 and 4 beyond the projected retirement dates for those units. (Tr. vol 16, 303.)

In rebuttal, witness De May stated that "the Company anticipates ongoing pressure to meet aggressive carbon reduction and emissions goals and to adapt further climate change-related policymaking. The Company already faces calls for early retirement of its coal-fired generating units, so it is seeking to take proactive steps in this case to position itself to meet these expectations. The Company believes that the time to act on this highly foreseeable policy shift is now." (Tr. vol. 11, 777.) Witness Spanos testified that the USOA requires that depreciation recover the costs of an asset over its service life. (Tr. vol. 16, 300.) Recovering costs after an asset is retired results in intergenerational inequity because future customers, who will not receive service from the retired asset, are forced to bear the costs for an asset that is already retired. (Id.) Witness Spanos explained that Public Staff's proposal will result in intergenerational inequity because it will result in DEP recovering a portion of the costs of Mayo Unit 1 and Roxboro Units 3 and 4 after they are retired. (Id. at 300-02.)

Witness Spanos also rebutted Public Staff witness Dorgan's justifications for Public Staff's proposal. Witness Spanos explained that DEP is not required to physically retire Mayo Unit 1 and Roxboro Units 3 and 4 prior to determining depreciation rates. (Id. at 301.) For the purposes of determining depreciation, DEP cannot wait until these units are retired to determine their service lives because the costs need to be recovered over the lives of the generating facilities. (Id.) Accordingly, witness Dorgan's first justification for using the original retirement dates does not comport with the USOA or generally accepted depreciation principles. (Id.at 301-02.) Additionally, witness Dorgan's argument that Public Staff has consistently advocated for setting depreciation rates at the original retirement date of the generating facility, and after physically retiring the facility, placing any costs into a regulatory asset account, is inequitable. (Id. at 302.) Witness Spanos correctly pointed out that any of the costs placed into a regulatory asset account and amortized over a given period will be recovered after these units are retired. (Id.) Therefore, Public Staff's proposal will result in intergenerational inequity. (Id.) Witness Spanos acknowledged that use of a regulatory asset may be required in some cases, such as instances when the date of retirement is close to the date of a filed rate case. (Id.) However, the accelerated retirement dates of Mayo Unit 1 and Roxboro Units 3 and 4 are 10 years from the test year in the Depreciation Study and, as such, there is sufficient time to recover the costs of these plants over their service lives. (Id.)

In light of all of the evidence, the Commission finds and concludes that the shortened life spans of Mayo Unit 1 and Roxboro Units 3 and 4 are appropriately incorporated into the Depreciation Study and used to set the Company's depreciation rates. The Public Staff has failed to justify the use of retirement dates from the prior 2018 DEP Rate Order. Prudent depreciation practices and the USOA support the retirement of Mayo Unit 1 and Roxboro Units 3 and 4 in 2029 because this will result in DEP recovering the costs of the generating facilities over their service lives. In this case, recovering the full costs of Mayo Unit 1 and Roxboro Units 3 and 4 over their shortened service lives will prevent future customers from paying for an asset that is already retired and from which they did not receive service. In sum, adopting DEP's shortened retirement dates for Mayo Unit 1 and Roxboro Units 3 and 4 will prevent intergenerational inequity.

General Plant Amortization Adjustments

In his Rebuttal Testimony, witness Spanos identified several areas where witness McCullar made errors in her calculation of depreciation expense. (Tr. vol. 16, 303-08.) These mistakes encompassed several discrete areas of her depreciation calculations. The first error identified by witness Spanos is witness McCullar's suggested utilization of two differing useful lives (one for DEC and one for DEP) in calculating amortization periods for Account 391 (Office Furniture and Equipment) and Account 397 (Communication Equipment). (Id. at 304-05.) After noting that witness McCullar did not challenge the general plant amortization period for these accounts in the DEC proceeding, witness Spanos observed that "[t]here is no compelling reason to use a different amortization period for these accounts for DE Progress than is approved and undisputed for DE Carolinas." (Id. at 305.) Witness Spanos also pointed out that the longer proposed amortization period for these accounts for DEP was unsupported by any depreciation analysis by witness McCullar. (Id. at 305-06.) Witness Spanos also testified that witness McCullar made several other mistakes relative to these accounts including the exclusion of millions of dollars of assets from these accounts that would need to be amortized given witness McCullar's calculations (resulting in understated depreciation expense associated with these assets), overstating the remaining life for assets in these accounts, and not updating the reserve adjustment for these accounts to reflect the impact of her other adjustments. (Id. at 307-08, 384-87.) There is no evidence in the record challenging these criticisms of witness McCullar's proposed changes to General Plant amortization.

Conclusion

In light of all of the evidence presented, the Commission finds and concludes that the depreciation rates proposed by DEP in this case, which are based on the revised Depreciation Study included as Spanos Ex. 1 and the Decommissioning Study reviewed in Docket No. E-2, Sub 1142, are just and reasonable, fair to both the Company and its customers, and therefore are approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 74-75

The evidence supporting these findings and conclusions is contained in the Company's verified Application and Form E-1; the evidence, orders and other matters of record in Docket No. E-2, Sub 1142 and Docket No. E-7, Sub 1146; late-filed exhibits, motions and Commission orders in this docket, and the testimony and exhibits of the following expert witnesses: DEP witnesses Bednarcik, Wells, Williams, Bonaparte, Lioy, Doss, Riley, Spanos, and Fetter; Public Staff witnesses Lucas, Maness, Garrett, and Moore; AG witness Hart; Sierra Club witness Quarles; and CUCA witness O'Donnell.[14]

The testimony and exhibits regarding DEP's CCR costs are voluminous, and the Commission has carefully considered all of the evidence and the record as a whole. Based on the Commission's consideration of the complete record in this case and for the reasons discussed further below, the Commission finds and concludes that the Company's CCR costs incurred from September 1, 2017 through February 29, 2020, were prudently and reasonably incurred, and that DEP is entitled to a return thereon, at its weighted average cost of capital authorized in this case, during the period in which these costs have been deferred and over the period in which they are amortized and brought into rates.

Introduction and Background

DEP seeks to recover a total of $440.1 million (on a North Carolina retail basis) coal ash basin closure costs, consisting of (a) actual costs of closure activities performed during the period from September 1, 2017 through February 29, 2020, all of which were incurred as a result of changes in the law with which the Company must comply, and all of which have been deferred by order of the Commission, and (b) financing costs incurred during the deferral period through August 2020. Pursuant to the "spend/defer/recover

[14] Further, at the request of the Company and without objection from any party, the Commission has taken judicial notice of certain evidence presented and admitted in the DEC-specific hearings in Docket No. E-7, Sub 1214. Where the Commission references the testimony and other evidence from the DEC-specific hearings referenced in this Order, such evidence has been judicially noticed pursuant to orders of the Commission.

model" outlined in DEP's last rate case, the Company's investors, both debt and equity, supplied the funds for these costs (CCR Costs). As a rate mitigation measure, DEP proposes to bring these costs into rates over a five-year amortization period beginning with the date new rates go into effect. DEP proposes further that it earn a return upon the unamortized balance, at its authorized weighted average cost of capital.

DEP requests that this Commission afford the same rate treatment it afforded to the Company in its last rate case.[15] The Company's overarching proposal focuses on (1) recovery "of" the coal ash costs the Company seeks in the current case (i.e., $440.1 million), along with (2) a return "on" those costs as they are brought into rates during the amortization period. The Company contends that recovery both "of" and "on" the incurred costs is warranted under the facts, the law, and the framework articulated in its 2018 DEP Rate Order. As such, the Company through various witnesses in this case establishes that since the last rate case, the Company and its investors providing the capital to finance CCR remediation investments have acted upon the explicit rules of the road established by our prior rate order. DEP argues that denying recovery of a return "on" those costs during the amortization would essentially amount to the Company providing a forced interest-free loan to its customers, an outcome manifestly unfair and confiscatory to the Company and its investors.

Many of the issues raised by intervenors in this case were litigated in the Company's last rate case discussed in this Commission's 2018 DEP Rate Order. For example:

- The Commission thoroughly considered the Company's "historical"[16] coal ash management practices, including their conformance to industry standards (2018 DEP Rate Order, at 142.);

- The Commission thoroughly considered the uncertainty prevalent prior to the enactment of CAMA and the CCR Rule and the impact that uncertainty had upon the Company's decision and timing for taking actions at all of its ash basins. As this Commission comprehensively addressed in the prior rate case, regulatory certainty was needed to close the Company's ash basins, to establish the level of cost to be borne by customers, and to avoid credible arguments of gold-plating (2018 Rate Order, at 183);

- On three prior occasions, including in the Company's last rate case, this Commission has also considered the Public Staff's "equitable sharing"

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[15] Docket No. E-2 Sub 1142, which was decided by the Commission's February 23, 2018 Rate Order Accepting Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase (2018 DEP Rate Order).

[16] "Historical" meaning prior to the changes in law wrought by the promulgation of the Federal CCR Rule in 2015, as well as the passage by the North Carolina General Assembly of the Coal Ash Management Act (CAMA) in 2014 and amendments to CAMA in 2016.

theory of cost disallowance, which the Commission emphatically rejected (2018 Rate Order, at 188-89);

- The Commission has also exhaustively evaluated the propriety and effect of the Asset Retirement Obligation (ARO) accounting employed by DEP to account for its CCR expenditures (2018 DEP Rate Order, at 194-96);[17] and

- Finally, the Commission has determined in its 2018 DEP Rate Order that the "spend/defer/recover" model employed by the Company in connection with its coal ash expenditures, entitles DEP to receive a return on such costs during both (1) the period during which those costs were deferred, and (2) the amortization period during which the previously deferred costs were brought into rates (2018 DEP Rate Order, at 194-96, 206).[18]

Although parties in this case disagree as to whether new facts or evidence illuminating any of these issues were adduced in the current docket, a close evaluation of the "new" evidence from DEP, in its rebuttal case, supplemented and added more detail to evidence the Company presented in the prior case, primarily as a result of intervenors raising the same issues that the Commission had already dealt with in the prior case. For example, the testimony of Company witness Marcia Williams brought to the Commission the perspective of a former EPA regulator, who led the EPA office that produced one of the major historical studies proffered by intervenors as "evidence" of the Company's historical imprudence, the 1988 EPA Report to Congress (1988 Report, Joint Ex. 13). Witness Williams testified that the 1988 Report *validated* the Company's historic ash management practices. As she noted, in the 1988 Report EPA concluded that no change was necessary to then-current coal ash waste management practices, inasmuch as those practices "appear[ed] adequate for protecting human health and the environment." (Joint Ex. 13 at 7-11.) And, as witness Williams also noted, EPA in crafting its 1988 Report was well aware that then-current waste management practices included, particularly in the Southeastern United States, unlined ash ponds. She noted that the 1988 Report found that these ponds

> [R]arely included the use of liners or leachate collection and that most facilities managing CCR did not have groundwater monitoring. The report found that 80 percent of CCR was disposed on the land (i.e., in surface impoundments, landfills, or other land-based units). Of the 483 surface impoundments in use at the time, only 45 were known to be lined while 303 were unlined and the liner status of 135 were unknown. In EPA's Region IV, which includes North Carolina, only 3 of the 195 surface impoundments were lined, while 153 were unlined and the liner status of 39 were unknown.

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[17] *See also* the Commission's June 22, 2018 Rate Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction in DEC's last rate case, Docket No. E-7, Sub 1146 (2018 DEC Rate Order), at 284-90. These issues were explored in more depth in the E-7, Sub 1146 Docket in light of additional development of ARO accounting evidence brought forward by the Public Staff. (*See* id. at 283.)

[18] *See also* 2018 DEC Rate Order, at 288-92.

(Tr. vol. 19, 222-23.)

In the Company's prior case and after a full trial on the merits, the Commission adjudicated these same contentions and found as a fact that "[s]ince the 1950s, standard industry practice at least in the Southeast, has been to deposit coal ash in coal ash basins." (2018 DEP Rate Order, at 142.) Even as late as 2010, when EPA proposed its CCR Rule, witness Williams testified that according to the EPA 74% of existing units were unlined, and 40% of "new" (meaning constructed during the 1990s or thereafter) units were unlined. (Tr. vol. 19, 422.) The Company did not construct any coal ash basins after 1982, and all of its basins were unlined, in accordance with standard industry practice at the time of their construction. Yet intervenors' presentation ignores these already-adjudicated facts, and forces the Company to prove them all over again.

In this case, intervenors ask the Commission to deny cost recovery on the basis of "fault"-based concepts, like "culpability." This is yet another aspect of intervenors' re-litigation approach. The Commission presented a detailed critique of the "fault" based and tort-like disallowance theories proposed in DEC's prior case. (2018 DEC Rate Order, at 260-65.) The Commission held that its

> [D]uty is not to determine liability to and assess damages for torts committed by management for injury to the environment or to receptors of contaminants. Environmental regulators and courts of general jurisdiction are the appropriate arbitrators of those disputes. DEC's unlined impoundments at issue operated pursuant to environmental permits as wastewater treatment facilities by DEQ or its predecessor. That agency's statutory mandate is environmental protection and would be the agency to rectify breaches of a duty of due care, if any, such as that advocated by certain Intervenors in this case. The issues before this economic regulatory tribunal is imprudence -- who should bear the remediation costs, the utility stockholders or its customers and on the basis of what justification.

(Id. at 261.) Noting further that intervenors equated lack of due care to management imprudence, the Commission stated that no one had cited any authority "to support the theory that, in determining the recovery through utility rates, costs of environmental remediation incurred by management to comply with express requirements of environmental regulators, management decisions should be assessed against a standard of due care." (Id.) These observations are still valid, and apply with equal force to DEP in this case.

Cost recovery under North Carolina law is regulated by the Commission under the prudence standard. Prudently incurred costs associated with service to customers are recoverable.[19] Such costs include financing costs – the cost of money – upon prudently

[19] The requirement that costs be associated with service belies the Public Staff's argument that many different types of costs are "shared" between shareholders and customers. For example, the Public Staff points to costs of senior management in a utility holding company. (*See* DEC Tr. vol. 26, 121-22.) Such costs may well be "shared" but prudence, imprudence, or even "fault" have nothing to do with the

incurred costs funded by the Company and its investors and deferred by order of the Commission in advance of being brought into rates, especially when they are brought into rates over time as a mitigation measure to reduce the impact of increased rates upon customers. Costs that are not prudently incurred are not recoverable. There is no room in such an analysis for tort-like "fault" concepts, and those concepts have no place in cost recovery under North Carolina law.

Legal Framework: Prudence and Industry Standards

The legal framework regarding cost recovery is long-established, and was well articulated by the Commission in the prior DEP and DEC rate cases. First, the operating principle underlying rate regulation generally is that the utility's reasonable and prudently incurred costs are recoverable in rates. (2018 Rate Order, at 196; DEC Order, at 257-58.) Second, under the evidentiary presumptions governing cost recovery the entirety of the utility's costs is deemed to be reasonable and prudent, unless challenged by an intervenor. (2018 Rate Order, at 196; DEC Order, at 259-62.) Third, if costs are challenged, the Commission must assess their prudence. (DEC Order, at 258-59, 265-66.)

Assessing prudence requires that the Commission apply rules and guidelines that have been developed over the past 100 years. As Company witness Steven Fetter testified, "the concept of prudence began in 1923 in a dissent from Justice Brandeis of the US Supreme Court[.]" (DEC Tr. vol. 26, 93; *see Missouri ex rel. Sw. Bell Tel. Co. v. Pub. Serv. Comm'n,* 262 U.S. 276, 306-07 (1923) (Brandeis, J, concurring and dissenting). Those rules and guidelines do not include "culpability." In his testimony, witness Fetter held up as a visual aid one volume of a two-volume reference work ("The Process of Ratemaking;" (*See* DEC Tr. vol. 26, 93; https://www.youtube.com/watch?v =PESiQ189BSc at approx. the 5:33 mark) and indicated that the index of the two volumes had "35 subcategories discussing various means of assessing prudence and what it means …[but that he] found nowhere in the two-volume text any mention of culpable or culpability." (DEC Tr. vol. 26, 93.)

In North Carolina, for at least the last 30+ years, the prudence framework has been applied as articulated by this Commission in its Order entered in Docket No. E-2, Sub 537 (the 1988 DEP Rate Case), in which the Commission approved, with some exceptions, costs DEP incurred in connection with the construction of Unit 1 of the Shearon Harris

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sharing. Rather, because senior management's duties are split between separate utilities – or even between regulated and unregulated entities – only a portion of them are necessary to support service by any specific utility. And, of course, costs must also be "known and measurable" (2018 DEP Rate Order, at 143.) Here, as in the Company's prior rate case, no party has questioned whether CCR Costs are "known and measurable." Finally, costs must be "reasonable" in size, but in the context of this case (as in DEP's prior rate case, *see* 2018 DEP Rate Order, at 196) the prudence framework captures the concept of "reasonable" – costs unreasonably large in size can hardly be said to have been prudently incurred.

nuclear plant. (*See* Order Granting Partial Increase in Rates and Charges, Docket No. E-2, Sub 537 (Aug. 5, 1988) (the 1988 DEP Rate Order).) There, the Commission set out the following principles governing the question of prudence:

First, the standard for judging prudence is "whether management decisions were made in a reasonable manner and at an appropriate time on the basis of what was reasonably known or reasonably should have been known at that time. . .. [T]his standard . . . must be based on a contemporaneous view of the action or decision under question. Perfection is not required. Hindsight analysis – the judging of events based on subsequent developments — is not permitted." (1988 DEP Rate Order, at 14.)

Second, challenging prudence requires a detailed and fact intensive analysis, and the challenger is required to (1) identify specific and discrete instances of imprudence; (2) demonstrate the existence of prudent alternatives – but a decision cannot be imprudent if it represents the only feasible way of accomplishing a goal; and (3) quantify the effects by calculating imprudently incurred costs. (Id. at 15.) As to quantification,

- The Commission can only disallow imprudent *expenditures* – that is, actions (even if imprudent) with no economic impact upon customers are of no consequence. As the Commission put it, "There can be imprudent actions without any economic impact. An imprudent decision or action can actually benefit the ratepayer economically. Thus, the identification of imprudence is not in itself sufficient." (Id.) The Commission rejected the importation of tort or "culpability" concepts into the prudence framework, and kept its focus where it statutorily belongs – upon rate regulation.

- The proper amount chargeable to customers is what the expenditure would have been absent the imprudent acts or decisions of management – in other words, the disallowance must be calculated as the difference between the (presumably) higher cost imprudent action and the (presumably) lower cost prudent action.

The North Carolina Supreme Court found "no error" in the Commission's articulation of the prudence framework in *State ex rel. Utils. Comm'n v. Thornburg (Thornburg)*, 325 N.C. 484, 489 (1989), and the framework was most recently followed in the Commission's February 24, 2020 Order in Docket No. E-22, Sub 562 (2020 Dominion Rate Order or Dominion Order), at 116.

A key factor in the prudence framework requires a challenger to identify "specific and discrete instances of imprudence." Necessarily embedded in this factor is an evaluation of the degree to which the utility has or has not acted consistent with industry standards. As two of the leading modern commentators on utility regulation, Lesser & Giacchino, state:

> Electric and natural gas utilities are required to follow a set of basic standards and practices, which together constitute *Good Utility Practice*. FERC defines *Good Utility Practice* for regulated electric utilities as follows:

> Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of *reasonable* judgment in light of the facts known *at the time the decision was made*, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Jonathan A. Lesser & Leonardo R. Giacchino (Lesser & Giacchino), *Fundamentals of Energy Regulation* 40 (Pub. Utils. Reports, Inc., 1st. ed., 2007) (citation omitted) (emphasis in original). Prudence is an attribute of "Good Utility Practice," and "Good Utility Practice" includes "the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period[.]" (Id. at 40-41.) That is, Good Utility Practice – prudence – is judged in relation to the utility's conformance with industry standards.

"Used and useful" is a concept directly embedded in the ratemaking statute – N.C. G.S. § 62-133(b)(1) states that the Commission must "[a]scertain the reasonable original cost of the public utility's property *used and useful, or to be used and useful* within a reasonable time after the test period, in providing the service rendered to the public within the State, less that portion of the cost which has been consumed by previous use recovered by depreciation expense[.]" (Emphasis added.) In general, the Supreme Court's treatment of the concept has been in the negative, i.e., asserted as a basis for its decision that something is not "used and useful" – for example, excess common facilities are not "used and useful" as a matter of law, *see Thornburg*, 325 N.C. at 495-96, and a water treatment plant that was not in service as of the end of the test year and would never again be in service was not "used and useful" within the meaning of N.C.G.S. § 62-133(b)(1). *State ex rel. Utils. Comm'n v. Carolina Water Serv., Inc.*, 335 N.C. 493, 508 (1994). The reverse, of course, is that if the expenditures do support and provide service to customers, the costs are "used and useful."

The burden of proof to show that rates are just and reasonable is on the utility. N.C.G.S. § 62-134(c). Nevertheless, intervenors have a burden of production in the event that they dispute an aspect of the utility's prima facie case. *State ex rel. Utils. Comm'n v. Intervenor Residents of Bent Creek/Mt. Carmel Subdivisions,* 305 N.C. 62, 76 (1982) (*Intervenor Residents*) ("The burden of going forward with evidence of reasonableness and justness arises only when the Commission requires it or affirmative evidence is offered by a party to the proceeding that challenges the reasonableness of expenses[.]"). If the intervenor meets its burden of production through the presentation of competent, material evidence, then the ultimate burden of persuasion reverts to the utility, in accordance with N.C.G.S. § 62-134(c). Finally, the Commission's orders must be based on competent, material and substantial evidence in the record of the instant proceeding. N.C.G.S. § 62-65(a).

Summary of the Evidence

The Company's Direct Case

Company witness Jessica Bednarcik presented the Company's direct case for recovery of coal ash. Witness Bednarcik testified that she is the Vice President, Coal Combustion Products (CCP) Operations, Maintenance and Governance for Duke Energy. She is a registered Professional Engineer in North and South Carolina and joined Duke Energy's Environmental Engineering group in 2005. In her current role, witness Bednarcik testified that she manages the team that defines, establishes, and maintains the Company's fleet CCP standards, programs, processes, and best practices for all fossil plant sites. Her team also oversees site operations and maintenance of CCP facilities, including CCR and dam operations and maintenance, production landfills, decommissioning and demolition, and byproducts management. (Tr. vol. 12, 31-33.)

In her testimony, she explained that DEP's compliance actions since September 1, 2017, have been and continue to be reasonable, prudent, and cost-effective approaches to comply with the federal CCR Rule and North Carolina's CAMA. (Id. at 33.) Under the CCR Rule and CAMA, DEP is required to close all of its CCR basins in North Carolina and South Carolina. For each activity the Company undertook, witness Bednarcik explained why the costs the Company incurred were necessary to satisfy federal and state regulatory requirements; appropriate in terms of meeting engineering and environmental standards; and timely and consistent with the site closure plans. In short, witness Bednarcik's direct testimony established that the actual costs incurred for ash basin closure at each site between September 1, 2017, and June 30, 2019, and the costs forecasted to be incurred through February 29, 2020, are reasonable and prudent. (Id.)

Witness Bednarcik explained that the Company's CCR costs reflect a continuation of ongoing projects that the Company initiated to meet its regulatory requirements. Costs for the initial phases of those projects were the subject of the Company's 2017 Rate Case, in which the Commission concluded that the Company's CCR costs were reasonably and prudently incurred. Witness Bednarcik also explained the closure options available for the Company's low-risk impoundments, including the Company's original plans to close those basins by cap-in-place. With assistance from experienced, professional engineering firms, the Company developed and submitted Closure Options Analysis Reports (COA Reports) to DEQ in fourth quarter of 2018 for the four sites. (Id. at 37-41.) On April 1, 2019, DEQ ordered Duke Energy to excavate all remaining coal ash impoundments in North Carolina, including the low risk impoundments at Mayo and Roxboro. (Id. at 42.) With the exception of preliminary closure plan development, the Company has not begun implementing cap-in-place closure at any of the sites covered by the order. Although some site work has been completed, none is specific to cap-in-place and would have to be conducted in an excavation closure, as well. (Id.)

Next, witness Bednarcik discussed the unique closure activities that the Company has undertaken at each of its sites, itemizing the associated costs the Company is seeking to recover in the instant case. In short, the Company is seeking recovery of the following costs related to compliance and closure of its CCR basins: Mayo ($22,520,499), Roxboro ($16,845,265), Asheville ($99,274,167), Sutton ($102,560,125), Cape Fear ($41,690,655), H.F. Lee ($86,609,666), Weatherspoon ($25,674,837), and Robinson ($20,762,298).[20] (Id. at 45-50, 54-55.)

In addition to closure costs, witness Bednarcik explained that the Company is seeking to recover the cost of paying a fulfillment fee to Charah, Inc. (Charah). In 2014, Duke Energy entered into a contract with Charah to dispose of coal ash from the Cape Fear, Sutton, H.F. Lee, and Weatherspoon sites, as well as DEC's Riverbend site. (Id. at 51.) After CAMA was amended to include beneficiation requirements, however, Duke Energy was unable to transfer the contracted-for amount of ash to Brickhaven and did not send any ash, whatsoever, to the Sanford Colon mine. (Id. at 51-52.) **[BEGIN CONFIDENTIAL]** [redacted] [**END CONFIDENTIAL]** Witness Bednarcik argued that engaging Charah was the best option for customers compared to the other options that Duke Energy had available at the time to meet regulatory requirements. (Id. at 52-53.)

Finally, witness Bednarcik explained that the Company has taken sufficient measures to ensure that costs for the closure projects are appropriately managed and minimized, and that all costs for which the Company is seeking recovery were reasonably and prudently incurred. (Id. at 56-57.)

Summary of Intervenors' Evidence

Public Staff

Prudence-Based Disallowances

Witnesses Garrett and Moore proposed a number of prudence-based disallowances with respect to the Company's CCR costs. Witnesses Garrett and Moore are principals in and founding members of Garrett & Moore, Inc., which provides environmental engineering and consulting services to power and waste industries. (Tr. vol. 15, 1266.) After reviewing the Company's direct case, they proposed three distinct disallowances: (1) witness Garrett proposed a disallowance of $33,670,054 which represents DEP's allocation of the fulfillment fee the Company paid to Charah related to the disposal of ash from the Sutton, Cape Fear, H.F. Lee, and Weatherspoon plants at

[20] The values filed in the Company's direct case are actuals through June 30, 2019.

the Brickhaven structural fill site (Id. at 1222.); (2) witness Garrett proposed a disallowance of $50,238,630 related to the hauling costs for disposal of ash from the Asheville plant to the R&B landfill in Homer, Georgia. (Id.); and (3) witness Moore proposed a disallowance of $130,348,392 in costs to construct the beneficiation units at the H.F. Lee and Cape Fear sites. (Id. at 1183.) Aside from these three cost categories, witnesses Garrett and Moore testified that they found the Company's requested recovery for CCR costs incurred at the Mayo, Roxboro, Sutton, and H.B. Robinsons plants to be reasonably and prudently incurred. (Id. at 1184-85; 1264-65.)

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

Next, witness Garrett testified that the Commission should disallow $50,238,630 of costs incurred related to the transport of 1,651,500 tons of excavated ash from the Asheville site to Waste Management's R&B landfill. (Id. at 1252.) In support of his recommended disallowance, he argued that there were two lower cost alternatives to disposal at the R&B landfill: (1) transportation of ash to Cliffside; and/or (2) depositing ash in an onsite landfill. According to Witness Garrett, the Company incurred **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in transportation costs that could have been avoided or reduced if the Company had adopted an alternate disposal strategy. (Id. at 1256-57.) Witness Garrett acknowledged that the Commission approved rate recovery for the same "transportation costs" in the 2018 DEP Rate Order, but argued that there has been a "material change in facts" since the Company's last rate case. He suggested that in 2018, Company witness Kerin testified that construction of an onsite landfill was impossible, but that witness Bednarcik's testimony in the current case contradicts that assertion. (Id. at 1261-62.)

Finally, witness Moore testified that the Commission should disallow $130,348,392 in CCR costs incurred to construct the Cape Fear and H.F. Lee beneficiation units. (Id. at 1138.) Specifically, witness Moore testified that the costs incurred by subcontractor Zachry Industrial Inc. (Zachry) for Engineering, Procurement, and Construction (EPC) at the Cape Fear and H.F. Lee beneficiation sites **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** were not reasonable and prudent because they were higher than the estimate for each project

[BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]** included in contractor The SEFA Group, Inc.'s (SEFA) response to the Company's Request for Information (RFI). (Id. at 1195.) In particular, witness Moore testified that the Company should have taken a number of steps to mitigate the high cost, including: (1) soliciting bids from a broader group of companies; (2) entering into three separate contracts for the construction of one STAR facility each, which he alleges would have been cheaper; (3) seeking statutory relief from the CAMA amendment's beneficiation requirements from the General Assembly; and (4) seeking guidance from the regulator, DEQ, as to whether some waiver or compromise would be possible, and what the consequences would be if it did not comply with the beneficiation requirements of the CAMA Amendment. (Id. at 1205-06.)

Discrete Culpability-Based Disallowances

Public Staff witness Lucas is an engineer with the Electric Division of the Public Staff. (Id. at 1438.) He testified that the Commission should impose two broad categories of disallowances: (1) expenditures of $1,240,328 related to groundwater extraction and treatment at the Asheville and Sutton plants, as well as the purchase of land at the Mayo plant which allowed the Company to mitigate potential exposure pathways; and (2) costs incurred to connect eligible residential properties to permanent alternative water supplies ($1,087,612) and/or install and maintain water treatment systems ($2,774,583). (Id. at 1441-42.)

With respect to groundwater extraction and treatment, witness Lucas acknowledged that the Commission allowed recovery of these expenses in the 2018 DEP Rate Order, but asked the Commission to take a "fresh look" at these costs in light of what he interpreted as numerous "violations" of groundwater standards since the Company's last case. (Id. at 1501.) He testified that, in his view, the evidence showed a total of 5,193 instances of new groundwater violations surrounding the Company CCR impoundments and that the Company had not challenged any of the measured exceedances. Witness Lucas argued that there would have been no need for the Company to extract and treat groundwater had it not been responsible for contaminating the groundwater in the first place. (Id. at 1501-02.) In support of this position, witness Lucas stated that legal counsel informed him that neither CAMA nor the CCR Rule would have required extraction and treatment of groundwater if there were no violations of groundwater quality standards. (Id.)

Regarding permanent alternative water supplies and installation and maintenance of water treatment systems, witness Lucas acknowledged that the costs were incurred pursuant to a CAMA requirement, N.C.G.S. § 130A-309.22(c1), but argued that the Company should be responsible for the costs because it created the contamination risk that, in his view, the legislature was forced to address. (Id. at 1530.) He further testified that the Commission previously disallowed the costs to provide bottled water that was similarly mandated by CAMA, and there is no meaningful difference between the two mandates with respect to recovery. (Id.)

Culpability-Based Disallowance – Equitable Sharing

In addition to the prudence-based disallowance, Public Staff witnesses Lucas and Maness also advocated that the Commission implement an "equitable sharing" of recoverable CCR costs, so as to allow the Company to recover only a portion of its otherwise recoverable CCR costs. Using this methodology, customers and shareholders would each be responsible for 50% of the recoverable CCR costs. (Tr. vol. 15, 1441, 1579.)

In support of his recommendation, witness Lucas testified that the Company has accumulated a record of ash basin-related environmental violations, which, in his view, have resulted in contamination of groundwater and surface water. According to witness Lucas, DEP is "culpable" for these alleged environmental violations and for creating a risk of future contamination. He therefore argued that it would be unjust to require customers to bear all the requested deferred coal ash costs. (Id. at 1448-49.)

Witness Lucas went on to testify that given the difficulty in identifying the costs of corrective action for environmental violations that DEP would have incurred in the absence of CAMA and the CCR Rule, as well as the difficulty in determining whether North Carolina would have required closure of ash basins in the absence of the spill at DEC's Dan River site, he does not believe the traditional imprudence approach is feasible for most of DEP's coal ash costs. He contended that equitable sharing is therefore appropriate because the costs of remediation and closure of the Company's coal ash disposal sites are intertwined with the Company's failure to prevent groundwater contamination as required by the 2L Rules. He concluded that this case presents factual circumstances (extensive environmental violations) where the determination of "reasonable and just rates" under N.C.G.S. § 62-133(d) requires a qualitative judgment of the Commission for a 50%/50% sharing of coal ash disposal site closure and remediation costs. (Id. at 1443-45.) However, even in the absence of "culpability" – that is, if the Commission disregarded witness Lucas's testimony entirely – witness Maness testified that he would still recommend "equitable sharing" due to the "magnitude and unique nature" of DEP's CCR costs. (Id. at 1591.)

Public Staff witnesses Lucas and Maness also provided testimony to respond to a portion of the Commission's Order Directing the Public Staff to File Testimony, dated January 22, 2020. The Order required the Public Staff to file testimony on several topics relating to CCR, including: (1) whether DEP included coal ash impoundment closure costs in net salvage for decommissioning DEP's coal plants; and (2) estimated costs for CCR remediation as initially proposed and after the December 31, 2019 Settlement Agreement between DEP and DEQ (Settlement Agreement).

Witness Maness provided the response on the net salvage issue and testified that a review of DEP's depreciation studies stretching back to 2000 does not indicate specifically whether the costs of decommissioning its coal ash impoundments were included in its net salvage percentages used to help determine depreciation rates. However, he testified that in its response to Public Staff discovery requests, DEP responded that the percentages used in the studies do not "include or account for anticipated costs of coal ash removal or remediation, or retirement/decommissioning of coal ash impoundments or storage facilities." Therefore, witness Maness testified that without more detailed information, he did not find it possible to conclude, with absolute certainty, that no portion of the previously utilized salvage percentages are allocable to impoundment retirement or closure costs. He, therefore, recommended that the Company address this issue in its rebuttal testimony. (Id. at 1589-92.) Regarding the Commission's request for cost estimates for CCR remediation, witness Lucas provided plant-by-plant estimates (Confidential Lucas Ex. 24) of total CCR costs from 2015 through 2079 that account for the Settlement Agreement. (Id. at 1521-25.) Witness Lucas testified that he was unable to develop estimates on an impoundment-by-impoundment basis, because DEP will often issue one contract to remediate an entire site without separating costs between various ash storage areas. (Id. at 1521.)

Other Intervenors' Disallowance Theories

The AG through witness Hart, Sierra Club through witness Quarles, and CUCA through witness O'Donnell submitted testimony supporting disallowances of DEP's CCR costs. None of these witnesses applied the prudency standard to support their recommended disallowances. Instead, the AG, Sierra Club, and CUCA based their disallowance recommendations on methodologies or theories that have never been applied or accepted by the Commission. Unable to identify enough discrete, imprudently incurred costs to "punish" the Company, intervenors also ask the Commission to disallow DEP's prudently incurred CCR costs.

AG Witness Hart recommended a range of disallowances, between approximately 10% and approximately 50%, on the grounds that the Company had not adequately addressed CCR storage and closure of its ash basins before 2014. While witness Hart is a Licensed or Professional Geologist in a number of states including North Carolina and South Carolina (Tr. vol. 13, 530-32), he testified that he is not an engineer, has never designed an ash basin, and has never managed or operated an ash basin. (Id. at 854.) He opined that the utility industry, including DEP, knew about the potential for contamination of groundwater from coal ash basins as early as the 1980s. (Id. at 538.) He then testified that by the early 2000s, as a result of EPA's Regulatory Determination in 2000 concerning the management of CCRs, that DEP should have known that it would face increased scrutiny, environmental sampling requirements, and potential mandates to close its ash basins. (Id. at 687.) After DEP began groundwater monitoring at all of its sites in 2008 through its voluntary participation in the Utility Solid Waste Activities Group (USWAG) Action Plan, witness Hart also opined that DEP was not proactive with regard to groundwater contamination at its coal ash basins, and instead chose to wait until regulatory agencies noted groundwater contamination concerns from DEP's data submittals in the 2009 to 2010 timeframe. (Id. at 689-91.) Witness Hart testified that while the CCR Rule and CAMA brought greater regulatory certainty about the management and closure of coal ash ponds, DEP should have taken steps to manage CCR differently under North Carolinas groundwater program (2L Rules). (Id. at 710.) However, at no point during his investigation did witness Hart attempt to meet with or interview anyone from DEQ to determine whether DEQ concurred with his opinion that DEP was not proactive enough. (Id. at 762-64.)

Witness Hart opined that DEP should have taken responsive action sooner and initiated a systematic plan to address its coal ash basins by converting facilities to dry ash handling, eliminating other wastewater streams, closure planning, and evaluating methods to reduce environmental impact while the basins were still operational. (Id. at 710, 830.) He opined that DEP's costs would be lower had it taken earlier action, but he admitted that any analysis of specific costs the DEP would have incurred had it responded earlier to the presence of groundwater impacts at its CCR basins is difficult. He explained that the difficulty arises from the fact that he could not retroactively determine what costs would have been incurred 10 or more years ago and because some of the costs would have resulted in additional costs that would have to be accounted for to determine whether there was a net increase/decrease in costs for customers. As an example, witness Hart explained that the conversion to dry ash handling would have led to increased costs to transport ash to an off-site or on-site landfill. Therefore, witness Hart was not able to provide line-by-line estimates of what the Company's earlier costs would have been. Instead, witness Hart concocted a methodology that assumed the activities for which DEP is requesting cost recovery at this time would have been similar to the activities that would have been conducted at an earlier time. Witness Hart first subtracted water connection costs and costs associated with "old" basins from DEP's overall request to arrive at an "Amount not excluded," or "Revised Cost." (Id. at 696-99.) He opined that the water connection costs and "old" basin costs – costs associated with basins that were "out-of-use" before 1990 – should be disallowed outright. (Id. at 696.) He then applied his time value of money methodology only to the "Revised Cost" by de-escalating the cost by considering the inflation rate between the time when DEP knew it had issues with groundwater contamination and when it started planning for basin closure in 2014. Based on his calculations, he recommended a disallowance range of $17.7 million if DEP had started closure planning in 2009 to $90.7 million if DEP had started planning in 1992. (Id. at 695-703.)

Sierra Club witness Quarles did not quantify a disallowance recommendation, but merely opined that the Company's CCR costs would have been lower had it converted to dry ash handling at some point in the past. (Tr. vol. 14, 595, 613-16.) He asserted that the Commission could disallow "avoidable costs" by multiplying the Company's estimated cost per ton by the tonnage of ash disposed after 1988. (Id. at 614.) Similar to his testimony in the Company's prior rate case, witness Quarles' testimony in this case asserted that it was unreasonable for the Company to continue operating unlined coal ash basins after the 1980s. He testified that the Company should have closed and remediated unlined impoundments and should have converted to dry ash handling in lined landfills. (Id.; c*ompare* Tr. vol. 6, 112 (Docket No. E-7, Sub 1146).)

Summary of Duke Energy Progress' Rebuttal Evidence

Rebuttal of Arguments Regarding Culpability and Historical Standards

The Company submitted the rebuttal testimonies of witnesses Wells, Williams, Lioy, and Bonaparte to rebut intervenors' testimony in support of unjustified disallowance recommendations of DEP's prudently incurred CCR costs.[21] Witnesses Wells and Williams focus their testimony on the pervasive flaws in intervenors' theories, namely: (1) intervenors apply modern environmental standards to historical practices, (2) intervenors ignore the discretion afforded to the Company's environmental regulators, and (3) intervenors cherry-pick data points to draw unreasonable inferences about what the Company and its regulators should have known or done at multiple points in time. The Company witnesses also showed that intervenors routinely ignored or dismissed scientific conclusions and regulatory decisions that did not fit their narrative. Witnesses Wells and Williams argued that the end result of intervenors' evaluation of DEP's historical CCR management practices is a biased and unfair presentation, which the Commission should not countenance. (Tr. vol. 19, 140.)

Witnesses Wells and Williams, together, provided a Company-specific, overall industry, and historical regulatory perspective of coal ash management practices over the past five decades. Witness Wells joined Duke Energy in 2009 as an Environmental Health and Safety (EHS) attorney after serving a similar role at General Electric Company. He transferred from Duke Energy's legal department to a role as Vice President of Duke Energy's EHS Coal Combustion Products division in 2015. He testified that he transferred to his current role as Vice President – Environmental Health and Safety Programs and Environmental Sciences for Duke Energy in 2018. (Id. at 131-32.)

For her part, Witness Williams testified that she has had an almost 50-year career centered on environmental protection and regulation, including government service with the EPA (over 17 years), senior management in the waste management industry (approximately 3 years), and consulting for private industry and public agencies (almost 30 years). She testified that her career has focused on compliance with the Resource Conservation and Recovery Act (RCRA), the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), the Clean Water Act (CWA), and the Toxic Substances Control Act (TSCA). (Id. at 205.)

Witness Williams testified that from 1985 to 1988, she served as Director of the Office of Solid Waste (OSW). She testified that during her tenure as Director, OSW worked on completing the various reports to Congress on "special wastes" required by amendments to RCRA that were enacted in 1980, including the Bevill Amendment. She explained that the Bevill Amendment exempted fossil fuel combustion waste from the "hazardous waste" category pending further study by EPA, and required EPA to submit a formal report to Congress regarding its findings. She testified that the 1988 Report to Congress entitled *Wastes from the Combustion of Coal by Electric Utility Power Plants*, which was cited throughout the record, was finalized and published by EPA at the end of her tenure as OSW Director. She also testified that during her tenure as Director, EPA was also completing a multi-year effort to characterize the almost 200,000 non-hazardous

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[21] The Commission has taken judicial notice of certain testimony and evidence presented and admitted in the DEC-specific hearings in Docket No. E-7, Sub 1214. Where the Commission references the testimony and other evidence from the DEC-specific hearings referenced in this Order, such evidence has been judicially noticed pursuant to orders of the Commission.

waste surface impoundments and over 15,000 landfills in the U.S. from the perspective of environmental design and operational controls. She testified that the 1988 Report on Solid Waste Disposal in the United States, which summarized the work performed by the Agency over the previous four years, was issued shortly after she left EPA. (Id. at 205-12.)

Company witness Lioy testified to AG witness Hart's improper use of the time value of money methodology and generally flawed approach. (Tr. vol. 11, 156-57.) He testified that he is a Certified Public Accountant (CPA), licensed in the state of North Carolina, and that he is a Certified Financial Forensics (CFF), Certified Construction Auditor (CCA), Certified Global Management Accountant (CGMA) and Certified Fraud Examiner (CFE). He testified that he has over 25 years of professional experience performing a wide range of accounting and financial analyses in connection with litigation, regulatory and other matters. He explained that he has extensive experience preparing calculations and performing hundreds of analyses using the time value of money concept. (Id. at 155-56.)

Witness Bonaparte testified about his observations and findings regarding CCR management strategies and closure planning of CCR surface impoundments in the Southeast region where DEP operates, including the states of Georgia, North Carolina, South Carolina, and Virginia, during the approximate timeframe of 2009 to 2011, or earlier. (Id. at 119-20.) He testified that he is a registered professional civil engineer in 19 states and is the Chairman and a Senior Principal with Geosyntec Consulting, Inc. and has nearly 40 years of professional experience in the areas of geo-environmental and geotechnical engineering applied to municipal, industrial, hazardous, and low-level radioactive waste disposal facility projects. He explained that his experience with CCR landfills and impoundments spans 25 years, and that he is knowledgeable regarding the physical and chemical characteristics of CCR, the Federal CCR Rule, and the design and construction of storage, disposal, and closure systems for CCR. (Id. at 118-19.)

Use of Unlined Ash Basins and Industry Standards

Witness Wells and Williams explained that DEP's initial construction and continued use of unlined ash basins even after 2014 was consistent with industry standards and applicable federal and state environmental regulations. In the Company's prior case and after a full trial on the merits, the Company's witnesses noted that the Commission found that "[a]t least since the 1950s, standard industry practice, particularly in the Southeastern United States, has been reliance on coal ash basins" (see 2018 DEP Rate Order, at 182-84),[22] and that as the 1988 Report itself indicated "'until recently, most surface impoundments and landfills used for utility waste management have been simple unlined systems.'" (Joint Ex. 13, at 7-11.) Even as late as 2010, when EPA proposed its CCR Rule, witness Williams testified that according to EPA, 74% of existing units were unlined, and 40% of "new" (meaning constructed during the 1990s or thereafter) units were

[22] *See also* 2020 DENC Rate Case Order, at 124-25 ("[U]nlined impoundments were the accepted repositories for storing CCRs prior to adoption of the CCR Rule, and compliance with the Clean Water Act and NPDES permits for water discharges was generally accepted as meeting the expectations of environmental regulators.")

unlined. (Tr. vol. 19, 422.) The Company did not construct any coal ash basins after 1985, and all of its basins were unlined, in accordance with standard industry practice at the time of their construction.

While intervenors suggest that the continued use of unlined basins after the 1980s was wrong, witness Wells explained that DEP's environmental regulators did not agree. Under delegated authority from EPA, DEQ and DHEC issued NPDES permits to DEP, which specifically authorized the Company to sluice fly ash and bottom ash to unlined basins, and then discharge the sluice water, after settling occurred, to surface waters. (Id. at 141-42.) He testified that neither the utility industry nor environmental regulators believed that unlined basins posed significant environmental risk, and therefore discontinuing use of unlined impoundments during their useful life was neither prohibited nor even discouraged. (Id. at 144.)

The opinions of witnesses Wells and Williams were reinforced by testimony presented by Company witness Bonaparte. Witness Bonaparte's review of publicly available data demonstrated that DEP's CCR storage practices were consistent with other utilities in the region. Witness Bonaparte summarized his findings:

- Information was reviewed for 93 CCR impoundments at the 40 generating stations. Of these, only three (3.2%) CCR impoundments were identified as having engineered closure plans and/or engineering-related closure planning in the 2009-2011 timeframe, or earlier. A few additional impoundments had received a layer of non-engineered fill above the CCR impoundment and/or had grass/vegetation growing on the surface of the impoundment, but this non-engineered closure activity is interpreted herein as being a simple extension of CCR impoundment operations.

- Of the 93 CCR impoundments reviewed, 85 (91%) were either directly reported or interpreted as being unlined; most of the CCR impoundments reviewed were reported as being active in the 2009-2011 timeframe (although some were inactive), and of the active impoundments, the majority were reported as receiving sluiced CCR at the time of the USEPA dam safety assessment reports.

- Only 1 of the 57 CCR Rule closure plans had any indication of closure planning for the subject CCR impoundment for the 2009-2011 timeframe, or earlier.

(Tr. vol. 11, 121; DEP Bonaparte Rebuttal Ex. 2, 9.)

Environmental Monitoring of Unlined Ash Basins

Witness Wells and Williams testified that, contrary to intervenors' assertions, DEP proactively navigated the evolving science regarding unlined ash basins and appropriately managed known risks. Witness Wells testified that studies performed by EPA, the industry, and DEP in the late 1970s and throughout the 1980s that were applicable to DEP's ash basins consistently demonstrated that harm to groundwater quality from its unlined impoundments was nonexistent or insignificant. (Id. at 144-45.) He testified that even today, groundwater and surface water monitoring has demonstrated that DEP's ash basins have not caused significant harm to the environment or public health. (Id. at 388.)

Witness Wells also testified that DEP certainly would have been aware of the industry studies, beginning with the EPA-sponsored study at DEC's Allen plant in the late 1970s, that groundwater risks associated with unlined ash basins were not materializing or were otherwise insignificant at DEP sites. (Id. at 161-62.) Witnesses Wells and Williams further testified that these studies in the late 1970s and 1980s culminated in EPA's 1988 Report to Congress, which concluded "that current waste management practices [including unlined ash basins] appear to be adequate for protection of human health and the environment." (Id. at 162, 223.)

Witness Wells testified that the Company did not simply rely on industry-wide studies to inform its understanding of unlined ash basins. He testified that in 1978, a year before North Carolina promulgated groundwater regulations, DEP initiated a groundwater study at Roxboro to evaluate impacts to groundwater from its 12-year old unlined ash basin. (Quarles Ex 7.) He further testified that one year later, in 1979, DEP commissioned a study to evaluate potential groundwater impacts from a yet-to-be-built unlined ash basin at Mayo. The studies of the existing ash basin at Roxboro and the proposed ash basin at Mayo indicated to the Company that its unlined ash basins in North Carolina did not pose a substantial threat to groundwater quality or human health. (Tr. vol. 19, 149-52, 160.) The Mayo study specifically concluded that it would be "difficult to imagine that any significant adverse impact on the ground water aquifer could be caused by ponding of the ash wastes at the proposed site." (Id. at 150.) The results of the Mayo and Roxboro studies reinforced the data that was becoming available through contemporaneous EPA-sponsored studies, that naturally occurring soils in North Carolina "can give essentially complete protection against trace elements that occur in ash pond sludge." (Id. at 152.) The Company's proactivity could also be seen in its decision to convert to dry fly ash handling at Roxboro due to high selenium levels in Hyco Lake. (Id. at 269.) As witnesses Wells and Williams explained, however, this conversion was prompted by effluent discharges to surface water – not groundwater conditions. (Id. at 178, 271.)

Witness Wells also testified about the Company's efforts to address groundwater concerns at its Sutton plant in the 1980s. His testimony demonstrated how DEP responded proactively and responsibly to evidence-based concerns, if and when they arose. He testified that at Sutton, the Company developed a groundwater monitoring network and agreed to construct a lined ash basin in 1984 to mitigate off-site groundwater impacts. He explained that the liner system at Sutton – consisting of compacted clay – met industry standards for liners at the time. Nevertheless, he noted that the Company is required to close the lined basin at Sutton under the CCR Rule and CAMA because it does not meet *modern* liner standards. He testified that this demonstrates the folly of intervenors' theory that the Company should or could have retrofitted all of its basins during this timeframe in order to avoid present-day costs. He further explained that the issues at Sutton were site-specific, it would have been unreasonable to assume those conditions existed at other plants. He testified that off-site conditions around Sutton were largely impacted by the volume of groundwater that neighboring industrial facilities were pumping to support their operations. He testified that no other DEP site is located next to an industrial facility that draws millions of gallons of groundwater per year. He explained that DEQ agreed, because it subsequently approved the construction of an unlined basin at Cape Fear in 1985 and did not require groundwater monitoring as a condition of its approval. (Id. at 152-58, 156.) Witness Wells also testified that, unlike a majority of DEP's ash basins which were located in the Piedmont region, Sutton was located in the Coastal Plain Region. Following the Sutton investigation, DEQ also required DEP to monitor groundwater as condition of Weatherspoon's NPDES permit in 1990, which was also located in the Coastal Plain. DEP continued monitoring at Weatherspoon until 2000, when it received authorization from DEQ to suspend further groundwater monitoring. (Id. at 162.)

In addition to conducting groundwater monitoring at Sutton and Weatherspoon, witness Wells testified that DEP also began monitoring groundwater at Roxboro in conjunction with its construction of an ash landfill. Later in the mid-2000s, witness Wells testified that DEP voluntarily participated in the USWAG Action Plan, which resulted in monitoring networks being developed at all of its sites. It was not until 2010 that DEQ required DEP to monitor groundwater at all of its sites. Until that point, witness Wells explained that DEQ never believed that a blanket groundwater monitoring requirement was scientifically supportable or necessary – otherwise DEQ could have imposed such a requirement using its state-law authority. (Id. at 165.) Witness Williams testified that DEP's groundwater monitoring efforts over time and the fact that it was monitoring groundwater at all sites by 2010 reveal a company that was "way ahead" of the industry as a whole. (Id. at 361.)

Given the Company's forthcoming and cooperative relationship with its regulators, witnesses Wells and Williams testified that it was unreasonable and unfair for intervenors to cast DEP's CCR management practices in a negative light. Witness Williams explained that the EPA worked closely to obtain state input into its 1988 CCR Report to Congress and into its work between 2000 and 2015 to evaluate minimum national protections for CCR. During these collaborative efforts, witness Williams testified that she was unaware that North Carolina indicated that it did not possess adequate authorities to protectively regulate CCR management. Moreover, she stated that DEQ had the ability to request that EPA use its authorities, if needed, to address any imminent and substantial endangerment. However, DEQ did not require DEP to modify the design of its ash ponds by requiring liners, did not require the ponds to close, or did not mandate groundwater monitoring earlier than they did, which she testified is a strong indication that DEP's operations were considered to be reasonable and protective by the Agency charged with protecting the North Carolina environment. (Id. at 276-77.) Even after DEQ began receiving DEP's groundwater data collected under the USWAG Action Plan, DEQ did not castigate the Company's historical practices. Witness Wells testified that DEQ's June 17, 2011 policy memorandum, titled "The Policy for Compliance Evaluation of Long-Term Permitted Facilities with No Prior Groundwater Monitoring Requirements" shows that DEQ took the opposite approach. (2011 DEQ Policy). He described the 2011 DEQ Policy, which included a detailed flow chart dictating the steps to be taken by DEQ and regulated facilities upon the identification of a groundwater exceedance near a coal ash pond.

Under the 2011 DEQ Policy, as long as DEP was cooperating with DEQ, DEQ would not take enforcement action against the Company. (Id. at 163-64.)

Intervenors' Fault-Based Disallowances

Public Staff

Witnesses Wells and Williams urged the Commission to once again reject the Public Staff's "equitable sharing" disallowance theory insomuch as the Public Staff's theory rests on DEP's "degree of fault" for past environmental practices. Witnesses Wells and Williams rejected witness Lucas's assertion that evidence of 2L violations and the existence of seeps demonstrated that DEP mismanaged its ash basins. As the Company witnesses indicated, the Commission explicitly rejected these theories in the Company's prior rate case.

Witness Wells faulted witness Lucas for relying on evidence of "new" violations since the Company's last rate case. Witness Wells explained that the increase in sample results that witness Junis deems "violations" is the result of the fact that intensive monitoring at the sites has continued since 2017. (Tr. vol. 19, 190-92.) He testified that, on some cases, new wells have been installed since 2017. He also noted that the location of compliance boundaries has changed, so that some wells were reclassified as being located "at or beyond a compliance boundary." (Id. at 191.) He explained that the purpose of the ongoing monitoring is to help the Company and its regulators better understand site specific conditions to develop appropriate corrective actions, and that the additional wells and sampling have achieved that purpose. He explained that, for example, DEP retained the consulting firm Arcadis to perform trend analysis on the wells at these sites. He testified that the trend analysis used several different methods to determine whether concentrations of constituents in individual wells are increasing, decreasing, or stable. He testified that based on this evidence, the characteristics of groundwater contamination around the ash basin remains similar to what the Company was seeing in 2017. (Id. at 192.) Witness Wells asserted merely counting the number of exceedances, as witness Lucas did, does not provide an accurate picture of groundwater conditions at any given site. Rather than indicating mismanagement, witness Wells asserted that DEP's groundwater assessment efforts over the past two years demonstrates responsible actions that enable the Company and its regulators to better understand the impacted areas and drive appropriate corrective action. (Id.) Witness Wells noted that witness Lucas's position leaves the Company in an untenable position. He testified that witness Lucas seeks to punish the Company for prudently meeting its CCR Rule and CAMA obligations to collect groundwater samples to characterize groundwater impacts. He also notes that if the Company had not complied with the CCR Rule and CAMA by reducing the number of wells drilled or samples collected to avoid witness Lucas's criticism, the Company would be vulnerable to legal challenges for violating those regulations (Id. at 192-93.) Witness Wells further explained that the Public Staff's analysis was flawed because it assumed that groundwater is constantly moving, and that every exceedance represents the contamination of previously uncontaminated groundwater. He explained that groundwater plumes do not act in the manner the Public Staff described; groundwater plumes are relatively static and typically stabilized, which is what has occurred at DEP ash basins. (Id. at 233-34.)

Regarding seeps, witness Wells asserted that the existence of seeps at ash basins is not evidence that the ash basins were mismanaged. Witness Wells testified that all earthen dams, including those that form surface impoundments for storing ash, are prone to the movement of liquid through porous features within those structures through a process known as "seepage." He explained that such seepage is common, expected, and, to a degree, necessary to maintain the stability of an earthen dam or dike wall. Absent a certain amount of seepage, he explained that earthen dams can become over-saturated, which may reduce the margins of safety and weaken structural integrity. He testified that certain of DEP'S CCR impoundments feature engineered toe drains within the dam structures to collect seepage. He testified that DEQ was long aware of the existence of seeps, but that DEQ exercised regulatory restraint and did not view them as a priority for inclusion of NPDES permits due to the low concentrations of constituents. (Id. at 186.)

Given the historical coordination between DEP and DEQ, witness Williams concluded that it would be wrong to characterize DEP's practices as mismanagement. She explained that the 2L standards are water quality remedial requirements that recognize that environmental contamination, including contamination that constitutes environmental harm, can result when an entity is in full compliance with all operational performance requirements. She clarified that remedial standards, like those contained in the 2L Rules, differ from design, construction, and operational standards that are contained in permits issued by DEQ, like NPDES permits. She explained that it was the responsibility of regulators to ensure that design and operational standards were adequate to meet performance, or remedial standards, like the 2L Rules. She testified that regulators normally do not issue permits if they believe there is some unprotected condition associated with permits that they are about to issue. (Id. at 347-51.)

AG

The Company offered the testimony of witnesses Williams, Bednarcik, and Lioy in response to AG witness Hart's recommended disallowances. While witness Hart attempted to quantify the costs the Company would have incurred had it taken additional actions in the past, witness Williams noted that his testimony acknowledged that such an undertaking would not be possible or accurate. (Id. at 321-22.) As he did in the DEC case, witness Hart first recommended a disallowance of DEP's costs to provide alternative water supplies (Step A). (Id.) Witness Hart's methodology in this case differed from his DEC testimony in that he also recommended a disallowance of costs associated with "basins that should have been taken out of service long ago at the Asheville, Cape Fear, HF Lee, Roxboro, and Sutton facilities [Step B]." Witness Bednarcik testified that this distinction between inactive basins and more recently active basins is without merit. She explained that, as with the active basins, DEP was under no regulatory obligation to formally close its inactive basins prior to the final CCR Rule and CAMA. (Id. at 323.) Witness Bednarcik testified that DEQ instructed DEP as late as 2009 that initiating closure of inactive basins was not necessary. (Tr. vol. 17, 143-45.) Witness Williams also testified that many of these basins had been subject to regulation by DEQ through the NPDES permitting process and therefore DEQ was certainly aware when they were taken out of service and did not impose additional closure requirements at that time or any time up until the passage of CAMA and the CCR Rule. She also explained that, at the time, ceasing the use of a pond and allowing it to decant naturally was considered an acceptable closure in North Carolina and throughout the industry. Therefore, she opined that removing the closure costs associated with complying with CAMA and CCR today is entirely arbitrary. She also noted that if DEP had voluntarily taken action earlier to formally close these inactive ash ponds, it is very unlikely that the closure would have included the excavation of the ash and much more likely that the closure would involve the removal of liquid and some revegetation. She testified that DEP's overall costs might very well have been more since it would have still been expending the costs it is now to remove the ash in addition to any earlier closure costs. (Id. at 323-24.)

AG witness Hart's third step (Step C) in his disallowance methodology is the same time value of money calculation that he performed in DEC's case. Witness Williams testified that adjusting for inflation is not relevant in evaluating whether costs expended at an earlier date are in fact more or less than costs expended today. She explained that by relying on inflation, witness Hart did not solve his underlying problem that predicting what might have happened earlier is difficult and entirely uncertain. She also testified that his selection of historical points in time was arbitrary, since no selected date represents when a reasonable and prudent company would have taken actions different than those taken by DEP. (Id. at 324.)

Company witness Lioy attacked witness Hart's methodology from an accounting perspective and opined that witness Hart's testimony and calculations supporting his recommended disallowance were flawed and unreliable. He testified that witness Hart's methodology demonstrated a fundamental misunderstanding of – and, therefore, a misapplication of – the concept of time value of money. (Id. at 157-58.)

Witness Lioy explained that the "time value of money" is a financial concept used to value a sum of money at different points in time. He testified that the underlying premise of the concept is that when comparing sums of money over different periods of time, you need to factor in potential earning power of the money. By way of example, witness Lioy testified that if one can earn 5% annual interest, a dollar today will be worth $1.05 in a year from now. He explained that the inverse is also true: a dollar a year from now is a worth approximately $0.95 today. (Id. at 158.)

Witness Lioy then explained how witness Hart incorrectly applied the time value of money concept. He testified that under witness Hart's calculation, $216 million in today's dollars (ignoring witness Hart's error of using 2014 instead of "today") is equivalent to $125 million in 1992 dollars. He then opined asserting that there is a "difference" between these figures, as witness Hart does, actually results from an apples (1992 dollars) to oranges ("today's" – although actually 2014 – dollars) comparison. As witness Lioy explained, these amounts are equivalent, just expressed at different points in time. He testified that a correct apples-to-apples time value of money analysis would determine that those amounts, compared in constant dollars, are equivalent. Witness Lioy explained that witness Hart's analysis actually demonstrates this: in constant dollars, the difference between the cost of the work had it been performed in 1992 ($125 million in 1992 dollars or its equivalent in today's dollars, $216 million) and the Revised Cost is zero. Witness Lioy testified that the result would be the same for the other dates selected by AG witness Hart (*i.e.* 1996 and 2009). Witness Lioy testified that witness Hart ignored that the point of calculating the time value of money is to make things equivalent, so that a comparison of costs at different time periods can be made using constant dollars. (Id. at 161-63.)

Witness Lioy opined that if witness Hart was attempting to quantify the amount DEP would have spent as of the earlier time periods in his analysis (1992, 1996, and 2009) in an attempt to quantify alleged imprudently incurred costs, witness Hart failed. He testified that all witness Hart did is make a mathematical calculation by subtracting the Revised Cost (expressed in earlier period dollars) from the Revised Cost (expressed in "today's" – actually 2014 – dollars). Witness Lioy noted that witness Hart admitted at his deposition that he "didn't know of" any standard texts or peer reviewed journals that supported his application of the time value of money concept in this fashion, indicating that his methodology was just subtraction. (Id. at 164-65.)

Witness Lioy also testified that witness Hart failed to consider a number of necessary factors that he would need to determine what DEP would have spent in 1992, 1996, or 2009. He testified that to fully evaluate work that would or could have been done in 1992, for example, would require the evaluator to take into account different applicable laws and regulations in 1992 as compared to today, and different technologies, means and methods available in 1992 as compared to today, among other potential factors bearing on cost. Witness Lioy notes that witness Hart does not even attempt to do this – indeed, he indicates that doing so presents many difficulties, including the difficulty "at this point in time to retroactively determine what costs would have been incurred or more years ago." (Id. at 165.)

Setting aside witness Hart's misapplication of the time value of money concept, witness Lioy also opined that witness Hart made numerous other errors that render his testimony unreliable. Witness Lioy testified that witness Hart erroneously took costs incurred between September 1, 2017 and June 30, 2019, and treats them as being incurred on a single day, December 31, 2014. He explained that witness Hart then discounted those costs back to January 1 of each of his selected dates. By treating costs in 2018 and 2019 as occurring in 2014, witness Lioy opined that witness Hart completely ignored the time value of money concept. Witness Lioy explained further that witness Hart's approach of assuming all costs (hundreds of millions of dollars-worth) occurred on a single day for purposes of his calculation defies reason and normal convention where the costs are incurred and spread out over multiple years as major projects are constructed and completed. Taking these factors into consideration, even if one were to accept his flawed methodology, witness Lioy opined that witness Hart's calculations are wholly unreliable, not prepared in accordance with normal accounting or financial conventions, and are wholly speculative. (Id. at 166-67.)

Sierra Club

Company witnesses Williams and Bednarcik rejected Sierra Club witness Quarles first ever attempt to quantify "avoidable costs" had the Company ceased using ash basins for storing CCR in ash basins in 1988 "or whatever the Commission concludes was the date by which the Company should have known the risk posed by continuing to store coal ash in unlined ponds and should have switched to dry disposal." (Id. at 293-94.) Witness Quarles suggested the "avoidable costs" could be calculated by multiplying the Company's estimated cost per ton for ash excavation by the amount of ash disposed after 1988 or the date of the Commission's choosing.[23] Witness Williams testified that there is no basis for asserting that 1988 is the date where the reasonable knowledge of risks warranted switching the management method for ash; in fact, the CCR Report to Congress that year and the 1993 EPA Regulatory Determination in no way supported such a conclusion. Witness Williams notes that these key documents concluded, after EPA's extensive review, that existing management methods were protective. She explained that the information available to the Company and regulators did not appreciably change until EPA began collecting data in the 2000s for the development of national regulations. By that time, witness Williams opined that it was reasonable and prudent for DEP to wait for the conclusion of that regulatory process as long as they worked with regulators to address any site-specific environmental issues. Further, witness Williams testified that if DEP had closed its existing surface impoundments prior to the CCR Rule and CAMA, there was no guarantee that a landfill constructed to replace the impoundment before the new rules were in effect would have been in compliance and may have been required to close, in which case excavation may have been required of the ash in the landfill. (Id. at 294-95.) As witness Bednarcik noted in her rebuttal testimony, at no point in his testimony does witness Quarles actually quantify the "avoidable costs" by applying methodology for which he advocates. (Tr. vol. 17, 146.)

Rebuttal of Accounting Arguments

Witnesses Doss, Riley, and Spanos testified regarding a number of coal ash accounting issues. These witnesses rebutted the Public Staff's positions regarding ARO accounting employed by the Company for its CCR basin closure costs, and, in particular, witness Maness's characterization of those costs as a deferred expense. Witness Doss highlighted that the Commission comprehensively addressed witness Maness's position on ARO accounting and deferral issues in the 2018 DEC Rate Order. Witness Doss noted that the Commission rejected Public Staff witness Maness' testimony and credited the testimony of Company witnesses Doss and McManeus. Witness Doss testified that, as this Commission concluded in the 2018 DEC Rate Order, "witness Maness' classification of these costs as "deferred expenses" is not persuasive, not supported by authority and

[23] The Commission rejected this type of disallowance methodology in the 2018 DEC Rate Case: "Attempts to identify years-old hypothetical past costs, for example, by allocating tons of CCRs to formulate inexact allocation percentages to be applied to 2015-2017 costs is to rely upon guesswork that simply is legally and equitably deficient." (2018 DEC Rate Order, at 263.)

not determinative given the nature of deferral and it is also incorrect as a matter of accounting. (Tr. vol. 16 at 340-341.) Witness Doss noted further that he provided detailed testimony in the Docket No. E-7, Sub 1146 explaining the GAAP, FERC and deferral requirements governing the Company's established of an ARO for CCR basin closure costs. In the 2018 DEC Rate Order, the Commission expressly credited his explanation on these issues and found his testimony uncontradicted in that case. (Id. at 335.)

Witness Doss explained further that relying upon guidance from this Commission, ASC 410, GAAP, FERC, and Duke Energy Corporation accounting policies, the ARO charging committee rigorously evaluates costs to be incurred to determine whether they qualify for ARO accounting treatment. (Id. at 336-37.) The charging committee's designations are internally reviewed by the Company's Coal Combustion Products (CCP) group to ensure that (1) all relevant facts were appropriately communicated by CCP and understood by the Committee, and (2) that the CCP group understands the decisions to properly categorize actual project costs. (Id. at 363.)

Witness Doss also demonstrated that the purpose for which costs are incurred determine the corresponding accounting classification, and provided examples of this principle in his live testimony. (Tr. vol. 17, 45-46.) Regarding potential sub-designations of ARO costs to reflect how DEP would have accounted for costs if such costs were not capitalized, witness Doss reiterated that in the 2018 DEC Rate Order, the Commission found that under GAAP, the costs (no matter what their classification), are capitalized pursuant to ASC 410-20-25-5. (Tr. vol. 16, 340-341.) To that end, DEP simply cannot reconstruct accounting systems, processes, and guidelines that would apply in a hypothetical non-ARO accounting world: "[n]ot only is [DEP's] accounting system incapable of facilitating a retroactive removal of accounting guidance, a retroactive assessment of what designation other than ARO might be appropriate for a particular activity would be pure speculation." (Id. at 365.)

Witness Riley also discussed the requirements of ASC 410, which beginning in 2003, required companies like DEP to assess, on an ongoing basis, whether it had a present legal obligation to remove, dispense, or remediate a long-lived capital asset. (Tr. vol. 13, 354.) Witness Riley noted that receiving less than a full return (which would be at the Company's weighted average cost of capital (Tr. vol. 13, 406) would be a cost disallowance. (Id. at 404-05.) This disallowance could require an immediate write-off not only of the amount of disallowed cost but potentially also additional future returns, if the Company were to determine that they were no longer probable of recovery. (Id. at 420-21.)

Rebuttal of Prudence-Based and Culpability-Based Disallowances

In her Rebuttal Testimony, witness Bednarcik rebutted the prudence-based and culpability-based disallowances recommended by the Public Staff and AG, including: (1) payment of a fulfillment fee to Charah, Inc. (Charah) ($36,670,054); (2) payment of a purported $30.42 per ton "transportation cost" to transport CCR from the Asheville plant to the R&B landfill in Homer, Georgia ($50,238,630); (3) construction costs at the H.F. Lee and Cape Fear Beneficiation plants ($130,384,392); (4) expenditures for groundwater extraction and treatment at the Asheville and Sutton plants, as well as the purchase of land at the Mayo plant which allowed the Company to mitigate potential exposure pathways ($1,240,328 on a system basis); and (5) costs incurred to connect eligible residential properties to permanent alternative water supplies ($1,087,612 on a system basis) and/or install and maintain water treatment systems ($2,774,583 on a system basis), as required by CAMA. She also discussed, in supplemental testimony requested by the Commission, the Company's projected future costs of basin closure pursuant to the settlement agreement entered into by and between DEP and the DEQ.

Charah Fulfillment Fee

With respect to the Charah fulfillment fee, witness Bednarcik testified that the Charah Master Contract contemplated that Duke Energy would provide a minimum of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

In an attempt to mitigate the risk that Charah might not recover all or part of its capital expenditures in the event of termination or any significant decrease in the amount of ash to be excavated, the parties agreed to the fulfillment fee provisions. **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]** Ultimately, however, the Company only issued purchase orders for 16,425 tons of ash to be delivered to the Brickhaven mine. This was the result of changes to Duke Energy's closure strategy mandated by amendments to CAMA requiring beneficiation that were passed *after* execution of the Charah Master Contract and issuance of the first purchase order. Witness Bednarcik explained that the fulfillment fee was subsequently calculated and paid according to the detailed terms of the contract. (Id. at 99.)

Asheville Transportation Costs

With respect to the costs the Company incurred to transport excavated ash from the Asheville site to Waste Management's R&B landfill in Homer, Georgia, witness Bednarcik explained that there has been no "material change in facts" since the Commission allowed full recovery of these costs in the 2018 DEP Rate Order. She testified that construction and utilization of an onsite landfill of any size was not feasible between September 1, 2017 and December 31, 2019 because construction of the Asheville combined cycle plant required the use of all available space that might otherwise be used for an onsite landfill. Even after construction was completed, witness Bednarcik testified that it was still both infeasible and unsafe to construct an onsite landfill with the capacity to store all of the ash in the 1964 Ash Basin plus the additional production ash from the coal-fired units. (Id. at 104-05.) To the contrary, the landfill that DEP is currently constructing on-site at Asheville is not the same 3 million ton-capacity landfill that the Public Staff argued should have been pursued in Docket No. E-2, Sub 1142, and the design process for the new landfill confirmed that offsite disposal was necessary for most of the CCR at Asheville because site constraints – including wetlands, property buffers, and topography – dictated the maximum capacity of the on-site landfill could be only 1.3 million tons of CCR. To achieve that capacity, witness Bednarcik explained, the Company had to use state-of-the-art technology that had never been used in North Carolina. Witness Bednarcik thus concluded that witness Garrett's proposed disallowance is based on flawed reasoning in two key ways: (1) even the current under-construction landfill would not hold the amount of ash transported between September 1, 2017 and December 31, 2019, and witness Garrett did not account for the cost of transporting and disposing of what would have been more than 300,000 tons of remaining ash; and (2) witness Garrett's disallowance does not account for the costs to construct any such landfill. (Id. at 105-06.)

Rebutting witness Garrett's argument that the Company should have selected Cliffside as the primary offsite disposal option for Asheville CCR, witness Bednarcik testified that contracting with Waste Management to send the CCR to R&B Landfill was the most prudent option since the Company would have incurred a termination fee if it was unable to work with Waste Management. (Id. at 113-14.)

From a technical standpoint, witness Bednarcik explained that the R&B Landfill provided two distinct advantages over Cliffside. First, transportation from Asheville to R&B Landfill could be accomplished on an established trucking route that runs primarily via interstate. While technically a shorter distance, transportation to Cliffside would have required ash to traverse approximately eight miles on two-lane country roads. The impacts to the community around Cliffside resulting from the track traffic needed to dispose 1.6 million tons of ash, witness Bednarcik explained, would have been significant. Second, witness Bednarcik testified that use of the R&B landfill allowed the Company to preserve the Cliffside landfill's primary responsibility, which was to store CCR from Cliffside. (Id. at 114-16.)

Finally, witness Bednarcik testified that witness Garrett's calculation of the purported "transportation costs" applied an incorrect methodology. To calculate the overall cost per ton purported to be "excessive," witness Garrett simply divided the total cost paid to Waste Management by the volume of ash transported. Witness Bednarcik explained that this calculation ignores the fact that Waste Management conducted other activities at Asheville related to water management and operations of the rim ditch. These transportation costs were part of a competitive bid analysis, and witness Garrett provides no details as to why he believes the rate to be "excessive." (Id. at 116.)

In sum, witness Bednarcik testified that the Public Staff has not provided any evidence – in the form of designs, plans, or otherwise – showing that a 3 million ton landfill is technically or practically feasible or that it could have been constructed and permitted in time to avoid offsite transportation of CCR from September 1, 2017 going forward. Absent that showing, there has been no material change that has obviated the need for offsite disposal. (Id.)

H.F. Lee and Cape Fear Beneficiation Costs

With respect to the H.F. Lee and Cape Fear beneficiation sites, witness Bednarcik testified that the RFI promulgated by the Company in August 2016 for the H.F. Lee and Cape Fear beneficiation projects did not ask responding contractors for any site-specific estimate of the EPC costs to be incurred for the beneficiation sites, nor did it provide project details that would be necessary to calculate such an estimate – in large part because the Company was still developing the project's precise scope and determining the locations for beneficiation. Nevertheless, the Company still intended to engage H&M to construct the beneficiation units based on its past work with SEFA, but H&M ultimately removed itself from consideration for the project. (Id. 116-18.)

Witness Bednarcik explained that the estimate SEFA provided was based on the costs it incurred to construct the Winyah STAR Facility in South Carolina, but there are several key differences between the Winyah and H.F. Lee and Cape Fear projects that would impact cost. (Id. at 119.) First, the Winyah plant is designed to produce 200,000 tons of ash product per year (a 120 MMBtu facility), while the H.F. Lee and Cape Fear beneficiation units must produce 300,000 tons of ash product per year (a 140 MMBtu facility) to meet CAMA requirements. CAMA's output requirement necessitated installation of a second external heat exchanger at H.F. Lee and Cape Fear along with all associated equipment. In addition, Winyah typically uses 70% ponded ash and 30% production ash. Ash at the Company's plants, on the other hand, is 100% ponded ash and required the addition of a grinding circuit to meet American Society for Testing Materials (ASTM) standards for concrete. The two facilities also use different scrubbers, and the dry scrubbers at H.F. Lee and Cape Fear required a second bag house with additional induced draft fans. Finally, the Winyah STAR facility was a refurbishment/addition to an existing carbon burn-out facility and SEFA was able to reuse a significant part of the carbon burn-out facility when constructing Winyah's STAR unit. The Company's facilities are new construction. (Id. at 122-23.)

According to witness Bednarcik, after H&M declined the project, in January 2017, the Company sent out an RFP for the balance of plant engineering and construction to four Companies – CBI, Fluor, Kiewit, and Zachry. Each of these companies were engaged in current EPC contracts with the Company and/or had successfully worked with the Company in the past. Because the detailed engineering had not begun and one of the three locations had not been selected, the RFP evaluation was based upon labor and equipment rates, not on overall estimated construction costs. Accordingly, the Company selected Zachry based upon its stated rates and not on any overall estimated contract price. In fact, after the Company selected Zachry as the EPC contractor in February 2017, the Company's internal estimating group worked with Zachry to develop an estimated overall cost, which was the amount included in the Zachry Master Contract 21281, dated November 3, 2017. (Id. at 125.)

Witness Bednarcik stated that witness Moore's suggestion that the Company should have sought statutory relief from CAMA's beneficiation requirements is not a real-world solution. First, there is no guarantee that the General Assembly would have actually granted such relief. Even if it did, it is likely that the original CAMA deadline would have passed before such a bill could be drafted, vetted, and passed. Witness Bednarcik testified that the suggestion that the Company should have sought guidance from DEQ upon learning of Zachry's estimated EPC costs is also misguided. DEQ is responsible for enforcing the State's environmental laws irrespective of an entity's cost of compliance. There are no cost considerations in the beneficiation provisions of CAMA and it would therefore be inappropriate for DEQ to make such considerations as part of its enforcement. (Id. at 127.) **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** (Id. at 128.)

Extraction Wells and Groundwater Treatment

In response to witness Lucas's proposed disallowance of these costs, witness Bednarcik noted that the Commission allowed the Company to recover these same types of costs in the Company's last rate case. She further discredited witness Lucas's claim that the Company identified 3,495 "new" instances of "groundwater violations" by explaining that an increase in measured exceedances does not suggest an increase in groundwater contamination in and around the Asheville, H.F. Lee, and Mayo plants. Rather, it is simply an indicator of the increased testing—both in frequency and location—the Company is conducting to identify the location of the plume. (Id. at 132-33.)

Permanent Alternative Water Supplies

Finally, witness Bednarcik argued that the Commission should allow the Company to recover its costs related to permanent alternative water supplies and the costs to install and maintain water treatment systems because these costs were incurred pursuant to statute and, as witness Lucas acknowledged, there has been no change since the Commission allowed recovery in the 2017 rate case. (Id. at 133-34.)

AG's Proposed Disallowance

Witness Bednarcik submitted supplemental rebuttal testimony to address certain issues raised in the supplemental testimony of AG witness Hart. In particular, she testified that witness Hart failed to recommend any concrete disallowance and instead simply contends that the Commission should impose a disallowance ranging from $218 million to $291 million to reflect potential cost savings had the Company completed closure. (Id. at 142.) Witness Bednarcik explained that witness Hart's testimony is flawed on many levels. First, witness Hart's recommendation to disallow all closure costs for long inactive basins ignores the regulatory landscape in place at the time of those closures. (Id. at 143.) Second, witness Hart failed to consider that the Company might have chosen a different closure strategy had it undertaken the task at an earlier date. Witness Bednarcik testified that any analysis of what strategy the Company would have adopted or what costs the Company would have incurred had it chosen to close inactive basins in 1989, 1996, 2003, and/or 2010 would have been nothing more than conjecture. (Id. at 144-45.)

Projected Future Closure Costs

Witness Bednarcik submitted supplemental testimony to respond 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 response, witness Bednarcik provided spreadsheets showing (1) the projected annual CCR remediation costs on a plant-by-plant basis from 2019 through 2078; (2) for each plant and year, a breakdown of the costs by remediation activities; and (3) for each plant's annual total cost an allocation to North Carolina retail based on the applicable energy factor. (Id. at 149.)

Witness Bednarcik also provided a brief explanation of the Settlement Agreement the Company reached with DEQ and a variety of special interest groups represented by the Southern Environmental Law Center (SELC) regarding closure of the Company's remaining ash basins. Witness Bednarcik explained that the Agreement details a reasonable and prudent plan for closure of the nine remaining CCR basins owned by DEP and DEC. Seven of the nine basins – including two at the Allen Steam Station, one at Belews Creek Steam Station, one at the Mayo Plant, one at the Roxboro Plant, and two at the Cliffside Energy Complex – will be excavated in their entirety with ash moved to on-site lined landfills. For the other two basins, at Marshall Steam Station and the Roxboro Plant, uncapped basin ash will be excavated and moved to lined landfills. While Duke Energy agreed to excavate all remaining ash rather than cap it in place, witness Bednarcik explained that the Company also secured key representations from DEQ and the community and citizen groups that would allow it to proceed with excavation as expeditiously as possible and without the threat of further challenges from either group. In particular, witness Bednarcik explained that the Agreement calls for expedited state permit approvals, which would keep projects on a rapid timeline, while at the same time 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. Entering into the Settlement Agreement also allowed the parties to resolve other pending litigation in state and federal courts, thereby ensuring that the impoundments are excavated on an expedited basis and to remove the uncertainty associated with litigation. (Id. at 152-54.)

Witness Bednarcik 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. With the exception of closure plan development, none of the site work that has been conducted at the Allen, Belews Creek, Cliffside, or Marshall sites is specific to cap-in-place closure and would be required to complete closure by excavation as well. (Id. at 155.) That said, witness Bednarcik explained that it would be 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, its remaining CCR basins. Aside from the expected margin of error surrounding estimates for both closure methods, it is difficult to assign a dollar value to the efficient regulatory approval process the Company secured through the settlement. (Id. at 156.)

Framework for Discussion

This Commission has specific duties and functions delegated to it by statute. "The Commission is a creation of the Legislature and, in fixing rates to be charged by public utilities, exercises the legislative function. It has no authority except that [authority] given to it by statute." *State ex rel. Utils. Comm'n v. Edmisten, 291 N.C. 451, 464 (1977)*. This Commission is not an environmental agency and is, therefore, not charged with the enforcement of the nation's or this State's environmental laws. *See State ex rel. Utilities Comm'n v. High Rock Lake Ass'n, Inc.*, 37 N.C. App. 138, 142 (1978), *appeal dismissed, review denied*, 295 N.C. 646. It is not a law enforcement agency, either. Nor is it a court of general jurisdiction, endowed with the responsibility to pass on issues of tort liability or due care under the circumstances. (*See* 2018 DEC Rate Order, at 260-61.) Rather, it sits in this proceeding with a specific task: to determine just and reasonable rates that the Company may charge its customers. In fixing such rates, the Commission is further charged with the task of examining and assessing the Company's costs, upon which those rates are founded.

The Commission concludes, based upon its careful review of all the evidence presented and its application of the governing legal principles to the facts that it has determined to be pertinent, that the Company has met its burden of showing that the CCR Costs it has and is incurring *are* known and measurable, reasonable and prudent, and used and useful in the provision of electric service to customers. As such, the Commission finds and concludes as follows:

- DEP seeks recovery of the actual CCR costs it incurred during the period from September 1, 2017 through February 29, 2020. On a North Carolina retail jurisdiction basis, these costs amount to approximately $404.6 million.[24] These costs are (a) known and measurable, (b) reasonable and prudent, and (c) used and useful in the provision of electric service to the Company's customers. As under N.C.G.S.§ 62-133 – the statute governing "[h]ow rates [are] fixed" in North Carolina – these costs are required to be included in rates, and the Commission may not legally disallow them. However, the Company proposes that, rather than recovering 100% of these already incurred costs immediately, it recover them over a five-year amortization period. The proposed five-year amortization period is just and reasonable, fair to the Company and to its customers, and the Commission approves it.

- DEP seek to recover the financing costs incurred during the Deferral Period and the Amortization Period. The Deferral Period is the period from the time the costs were first incurred through the date upon which they begin to be brought into rates; for purposes of this case, through August 31, 2020. The Amortization Period is the period over which deferred CCR Costs are amortized – that is, paid by customers over time – as they are brought into rates. The financing costs equate to a return "on" prudently incurred CCR costs. They are allowable and allowed.

In short, the Company has met its burden – both the prima facie burden of production and the ultimate burden of persuasion – of showing its entitlement to a recovery "of" CCR Costs. The Company, having met that burden, is entitled under the applicable legal standards to a return "on" such Costs at its weighted average cost of capital that the Commission sets in this case.

In remaining sections of this Order, the Commission explains and provides the basis for its decision. The Commission's Order resolves four basic questions:

1. Whether intervenors' "fault"-based theories of disallowance, and specifically the Public Staff's "equitable sharing" proposal, are viable under the law. Consistent with past orders, the Commission answers this question "No."

2. Whether intervenors' cost disallowance proposals that apply to the Company's historical actions and decisions – that is, actions and decisions taken long before, and in some cases decades before, the time period in which the costs sought for recovery in this case were incurred – are viable under the law. Viewing these actions and decisions through the lens of the prudence framework, the Commission again answers this question "No" – to the contrary, applying the prudence framework intervenors' challenges

[24] The amount of actual CCR costs is net of the amount (approximately $5.5 million) the Company had been collecting for coal ash basin closure through depreciation expense as allowed by the Commission in a previous DEP rate case, Docket No. E-2, Sub 1023, and the remainder of which are the financing costs incurred by the Company upon these deferred costs through August 2020.

fail, because (a) intervenors have not quantified the impact of the Company's actions and decisions upon customers, and (b) in any event, the Company has shown that its actions and decisions were prudent in light of industry standards and knowledge at the time they were taken and made.

3. Whether a return on any costs to be recovered is allowable. The Commission answers this question "Yes." For prudently incurred CCR Costs that investors advanced to customers, DEP is entitled to earn a return during both the Deferral Period and the Amortization Period at its authorized weighted average cost of capital established in this case. This determination is consistent with the mandates of the United States and North Carolina Constitutions, the rate fixing statute, decisions of the North Carolina Supreme Court, and the spend/defer/recover framework established in the 2018 DEP Rate Order.

4. Whether the prudence-based challenges to the Company's coal ash costs, or other discrete challenges mounted by the Public Staff and the AG's should be allowed. The Commission answers this question "No." The Company has carried its burden of proving that the costs are prudently incurred.

Discussion of Question #1: "Fault"-Based Theories of Disallowance, and Specifically "Equitable Sharing"

The Commission determines that intervenors' "fault"-based concepts are not viable cost disallowance mechanisms under North Carolina law. Here the Commission discusses in detail the principal "fault"-based theory – the Public Staff's "equitable sharing" concept, and also the Public Staff's specific "fault"-based disallowances relating to the Company's environmental practices, as they relate to seeps and groundwater exceedances.

"Equitable Sharing"

Intervenors' principal "fault"-based theory is advanced by the Public Staff. Slightly over three years ago, when the Public Staff filed testimony in DEP's last North Carolina rate case, it unveiled its theory of "equitable sharing,"[25] whereby it proposed that DEP's *prudently incurred* coal ash costs be shared 50/50 between DEP and its customers. Public Staff proposed the same theory in DEC's last rate case, albeit with a different sharing ratio of 51% for DEC and 49% for customers. Public Staff then proposed the same theory, with yet a different sharing ratio, in Dominion Energy North Carolina's (Dominion) last rate case – 60/40 with customers bearing the larger share. In each of those cases, Public Staff purportedly based its apportionment of costs on some (undefined) degree of utility "culpability" for the incurrence of those costs. At the same time, Public Staff argued that "equitable sharing" would be appropriate irrespective of a

[25] That testimony was filed on October 20, 2017.

finding of "culpability" because the CCR costs were "extremely large." In each one of those cases, the Public Staff asserted that adoption of the theory and the Public Staff's chosen sharing ratio, was within the Commission's discretion. And in each one of those cases, the Commission rejected the Public Staff's theory because it was arbitrary, capricious, and unfair. The Commission concluded that, if it adopted "equitable sharing," its order would be overturned on appeal because it would be arbitrarily and capriciously disallowing prudently incurred costs. In this case, the Commission again rejects the Public Staff's "equitable sharing" theory because it remains arbitrary, capricious, and unfair.

Assessing management decisions, alternatives to those decisions, and quantifying costs differences between the decisions and alternatives are vital requirements of the prudence framework. Public Staff witness Lucas acknowledged in his pre-filed testimony that the disallowance was not based upon the prudence framework. (*See, e.g.*, (Tr. vol. 15, 1444 ("I do not believe the traditional imprudence approach is feasible for most of DEP's coal ash costs."); 1449 ("the equitable sharing recommendation is not based on the imprudence standard"). The Public Staff concedes, therefore, that no disallowance of CCR Cost under the prudence framework would be permissible, except of course, through a Garrett and Moore-type prudence analysis. In this case the Public Staff once again advances its theory, asking the Commission to "take a fresh look" at its arguments. (Tr. vol. 15, 1501, 1513-14.) The Commission declines Public Staff's invitation. There is no basis for a "fresh look" – the Public Staff's theory is today just as flawed as it was when the Commission rejected it in DEP's and DEC's prior cases:

> First, the concept is standard-less, and, therefore, from the Commission's view arbitrary for purposes of disallowing identifiable costs – there is no rationale that supports a substantially large 51% disallowance. The Public Staff chose a desirable equitable sharing ratio, then backed into the mechanism to achieve that level of disallowance, leaving the allocation subject to an arbitrary and capricious attack, particularly as it provides no explanation as to why the "equitable" split for DEP in the 2018 DEP Case was in its view 50-50, while the "equitable" split in this case is 51-49. As the Commission held in the 2018 DEP Case, the "Public Staff provides insufficient justification for the 50/50 [split] as opposed to 60/40 or 80/20 ...." 2018 DEP Rate Order, p. 189.

2018 DEC Rate Order, at 273. In the Company's prior case the Commission indicated further, citing *Tate Terrace Realty Investors, Inc. v. Currituck Cty.*, 127 N.C. App. 212, 222-23 (1997), that a "determining principle" was missing from the Public Staff's proposal, and that in its absence "were the Commission to adopt … [equitable sharing], the Commission very well could be found to be acting arbitrarily and capriciously, and subject itself to reversal." (2018 DEP Rate Order, at 189) (*citing Sanchez v. Town of Beaufort*, 211 N.C. App. 574, *disc. review denied*, 365 N.C. 349 (2011).).

Nothing has changed since the Commission last rejected "equitable sharing" in Dominion's Rate Case. The Public Staff followed the exact same methodology, described in witness Maness' testimony, as it did in the last case (and in DEC's last case, and in Dominion's last case) to create the sharing apportionment. First, witness Maness removed unamortized coal ash costs from rate base, thereby eliminating any return on that unamortized balance. (Tr. vol. 15, 1565.) Next, he chose an amortization period that would result in the Public Staff's desired sharing ratio. (Id. at 1577-79.) In other words, just as it did in the Company's last case (and in DEC's last case, and in Dominion's last case), the Public Staff merely chose its desired sharing percentage, then mathematically backed into that percentage by using the amortization period as a toggle. It is the Public Staff's choice of the sharing percentage that is arbitrary and "without a determining principle."

Commissioner McKissick gave the Public Staff an opportunity to explain whether a determining principle exists for the "culpability" standard; that is, "a standard that applies not simply to the facts of this case, but to other cases that the Commission might consider if they're going down the path of equitable sharing." (Tr. vol. 15, 1807.)[26] Despite having espoused "equitable sharing" and "culpability" for the past three years, the Public Staff was still unable to supply this determining principle, as is evident from its submission of Public Staff Late-Filed Exhibit No. 1 (PS LFE No. 1).

The prudence framework is an established standard of conduct against which the utility's actions may be judged. Commissioner McKissick's request was for the Public Staff to articulate criteria by which the Commission could *objectively*, not *subjectively*, judge a utility's conduct so as to determine whether otherwise recoverable costs should be disallowed. According to PS LFE No. 1, "equitable sharing" and "culpability" are grounded in the Commission's discretion, granted by N.C.G.S. § 62-133(d), to consider "all other material facts of record" in setting rates that meet the statutory mandate of being just and reasonable, and fair to the utility and the consumer. (Id. at 3.) However, consideration of all other material facts "is not a grant to roam at large in an unfenced field." *State ex rel. Utilities Comm'n v. Pub. Serv. Co. of N.C.*, 257 N.C. 233, 237 (1962).

Commissioner McKissick asked the Public Staff to provide the fencing – the Public Staff's response was that the Commission's discretion essentially has no bounds.[27] PS

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[26] On September 28, 2020, the Company filed with the consent of the Public Staff, the AG, and Sierra Club an Amended Joint Stipulation (Amended Stipulation) regarding certain coal ash and coal ash accounting-related testimony and exhibits admitted into evidence during the DEC-specific hearings. Pursuant to the Amended Stipulation, the stipulating parties agreed that that evidence was admissible in the DEP-specific hearings, and, specifically with respect to testimony, that they recognized "that a question posed live in the [DEC] hearing to a witness in that hearing would be answered in like fashion by that same witness, tailored to [DEP], in the [DEP] hearing." (Amended Stipulation, at 3.) The parties further noted in this regard that "Public Staff witness Junis appeared in the [DEC] case, but is not appearing in the [DEP] case, and that his place in the [DEP] case is being assumed by Public Staff witness Jay Lucas. Accordingly, in this instance, the 'same' witness as Charles Junis in the [DEP] case is understood to be Public Staff witness Lucas." (Id. at fn. 2.) During the course of the DEP hearing all stipulated testimony was in fact introduced into evidence and is part of the DEP Record.

[27] In *State ex rel. Utils. Comm'n. v. Thornburg*, 314 N.C. 509, 516 (1985) the Supreme Court specifically warned that the Commission under Section 62-133(d) did not in fact have "unbridled discretion in exercising its judgment."

LFE No. 1 does not articulate *any* rules, much less rules that can be objectively and generally applied to conduct beyond the facts and circumstances of this case. The Public Staff admitted as much, stating, "[t]he determination of culpability is fact and case-specific, and is not amenable to a bright-line test." (PS LFE No. 1.) Rather, PS LFE No. 1 conclusively proves that the Commission's insight and holding from the 2018 DEC and 2018 DEP Rate Orders was exactly correct – "culpability" and "equitable sharing" are standard-less concepts without any consistent and objectively understandable rationale. To the contrary, they are merely expressions of the Public Staff's "judgment" as to how and in what ratio coal ash costs should be shared between the Company and its customers – an arbitrary and continuously fluctuating judgment of the Public Staff alone. Were the Commission to agree and adopt that judgment, it would be acting no less arbitrarily. And for an administrative and adjudicatory body to act arbitrarily is, of course, contrary to law.

The Commission must "set rates that will protect both the right of the public utility to earn a fair rate of return for its shareholders and ensure its financial integrity, while also protecting the right of the utility's intrastate customers to pay a retail rate which reasonably and fairly reflects the cost of service rendered on their behalf." *State ex rel. Utils. Comm'n v. Nantahala Power & Light Co.*, 313 N.C. 614, 691 (1985). The Commission achieves this balance through the prudency standard, which is the Commission's sole guiding standard for assessing disallowances under N.C.G.S. § 62-133. The Public Staff knows how to apply the prudency standard when it wants to, and it has done so in this case through the discrete disallowance proposals recommended by witnesses Garrett, Moore, and Lucas. The Commission does not weigh the equities, nor can it fashion any relief it wants, rather it is bound by the ratemaking framework set forth in N.C.G.S. § 62-133. Applying a standard of care to a public utility's management decisions would irreparably upset the balance to which public utilities and customers are entitled.

Environmental Practices – Seeps and Groundwater Exceedances

In PS LFE No. 1 the Public Staff asserts that the Company had "***some*** degree of responsibility or fault" for the consequences of its past environmental practices. ((Id. at 1.) (emphasis added).) It mentions specifically surface water discharge issues (seeps) as well as North Carolina's groundwater classification rules and standards, known as the 2L Rules. Both subjects were addressed in detail in the Company's prior case, with the Public Staff's position being soundly rejected, yet both are revived again in this case. The Commission once again rejects both challenges.

The Public Staff insists that "unauthorized seeps that DEP has admitted to environmental regulators" violated the terms of the Company's NPDES permits. (Tr. vol. 15, 1442.) The Public Staff claims "unauthorized seeps" are evidence of the Company's "culpability" for environmental violations. Under its tort-based framework, the Public Staff asserted that the Company is at "fault" for those violations and should be responsible for the resulting harm. Setting aside the fact that the Public Staff assigns no actual dollar impact to customers of these "violations," to equate seeps with management imprudence is simply wrong when addressed in the context of the actual story of the seeps.

That story was presented in detail by Company witness James Wells, and was not contradicted by any witness. (*See* Tr. vol. 19, 186-90, 450-65.) All earthen dams seep; indeed, seepage is necessary to maintain the stability of the dam. Engineered seeps are designed to collect seepage within the dam structures. In 2010, EPA instructed the States with delegated authority under the Clean Water Act, which would include North Carolina, to evaluate seeps within the permitting process. DEQ decided it had other more pressing priorities, particularly since the effluent composition of the seep water was similar to effluent from the ponds themselves, but in substantially lower concentrations, and also as no other state was following through with EPA's request. Regardless of its priorities, DEQ struggled to find common ground with EPA on the appropriate regulatory approach to seeps. In 2014, four years after EPA tried to induce the States to address seeps but with no action on that subject taken by DEQ, and in an effort to seek regulatory certainty as to seeps, DEP and DEC[28] sought to include all "areas of wetness" at its coal ash basins in its NPDES permits – and DEQ, for whatever reason, sat on the application for years.[29] Eventually, in 2018 – *four years after DEP applied for the permits, and eight years after EPA's instruction to the States regarding evaluation of seeps* – DEP and DEQ agreed on a regulatory approach as to seeps, which has now been implemented.

Witness Wells provided essentially the same testimony in the Company's last case (*See* 2018 DEP Rate Order, at 177) and in DEC's last case. The Commission summarized this testimony in the prior DEC case:

> Company witness Wells testified on rebuttal … [in response to Public Staff witness Junis who] suggested that the existence of seepage at the Company's CCR impoundments is evidence of the Company's "culpability." Witness Wells explained that the Public Staff's position ignores (1) the fact that the EPA first directed permitting authorities to address seeps in 2010, (2) the Company's attempts to obtain regulatory certainty as to seeps, and (3) DEQ's challenges in implementing EPA's direction. Tr. Vol. 24, p. 226.

2018 DEC Rate Order, at 250. In both cases the Commission declined intervenors' invitation to view seeps as evidence of mismanagement justifying cost disallowance. As it indicated in the Company's prior case, even the Joint Factual Statement underpinning the Company's guilty plea noted that "DEQ and DEP have been in long-standing negotiations as to whether seeps are a violation of law and since 2014 whether seeps should be covered by the NPDES permit … [and that according] to statements made in the criminal case, DEQ has currently not made a determination on this issue." (2018 Rate Order, at 184 (record citations omitted).)

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[28] The merger of Duke Energy Corporation and Progress Energy, Inc. had by then occurred. The merger became effective in July 2012.

[29] The Commission intends no criticism, express or implied, of DEQ for this delay. The Commission understands that the issues DEQ had to deal with regarding seeps were novel and complex, and that DEQ was required to navigate between its own priorities and (possibly at times unclear) direction from EPA. The Commission's only point is that the delay is by no means attributable to any "fault" on the part of DEP or DEC.

The Commission in the Company's prior case declined to view the seeps as evidence of mismanagement – because they are *not* evidence of mismanagement. Yet the Public Staff wants in this case to re-litigate the exact same issue, on the exact same theory, with the exact same evidence – and expects a different result. The Commission rejects this approach. Whether the existence of seeps – known by and disclosed to the environmental regulator, and the subject of long-standing negotiations between the Company and its environmental regulator regarding the best and most effective way of dealing with resulting environmental impacts (if any) – is in violation of the Clean Water Act is not an issue for the Commission. It is an issue for the environmental regulator, and was resolved by the environmental regulator. The questions for the Commission are (1) whether the existence of seeps constitutes mismanagement, and, if so, (2) whether and to what degree the Company's incurred CCR costs have been impacted by that mismanagement. The answer to the first question was and still is, No. Even if the Commission answered Yes to the first question, the Public Staff has provided no evidence on which to base an answer to the second question.[30]

As it did with the Company's seeps, the Public Staff recycled its theory from the Company's last rate case that DEP was "culpable" for groundwater violations. The Commission dealt with this at length in its 2018 DEP Rate Order, and the Public Staff is once again simply wrong. First, the Public Staff's assertion of "culpability" or "fault" is based wholly on what it alleges are the large number of "violations" of the 2L Rules. As witness Lucas put it, there are "7,411 groundwater exceedances confirmed by DEP's own groundwater monitoring data, in violation of the state's 2L rules." (Tr. vol. 15, 1442.) But relying upon a simple count of exceedances does not equate to mismanagement; rather, it is misleading and constitutes "a very serious flaw in this analysis." (Tr. vol. 19, 432.)

Witness Lucas's testimony is based upon a complete misapprehension of the facts. The Public Staff's position[31] is that the number of violations is a factor of sampling "new contaminants" because of movement of the contaminant plume. (Tr. vol. 15, 1765.) Witness Williams, who is an actual expert on groundwater, indicates otherwise. She testified that the Public Staff "tried to explain that … [its methodology] wasn't flaw[ed] because groundwater is constantly moving, and therefore … every exceedance is a new example of where the groundwater has moved and contaminated … additional clean groundwater." (Tr. vol. 19, 432.) But she added "that actually isn't how groundwater behaves." (Id.) Rather, if the plume is stable, then these are not "new exceedances" (id.) – and the plumes at the DEP basins are, indeed, stable. As witness Wells stated, "[I]t's sitting, and it's stable, and our multiple models say it will continue to do so for hundreds

[30] Sierra Club suggests that the economic consequence for the existence of seeps is the cost of basin closure – hundreds of millions of dollars, so far. The Commission rejects this theory. The Company could have – and did, during the limbo period in which DEQ was either unwilling or unable to act on seeps – simply pump water seeping out of the basins back into the basins. (Tr. vol. 19, 460.) It was not required to close the basins on account of the seeps.

[31] The position was articulated by Public Staff witness Junis in the DEC-specific hearings, but his articulation of that position is made part of the DEP Record through the Amended Stipulation.

of years, as we see it, if we take no further action." (Id. at 388-89; *see also* Tr. vol. 20, 26 (Company's stable plume does not present health risk).)

Simply counting exceedances is also "not a meaningful thing to do" (Tr. vol. 19, at 432-33) because in the assessment phase of a groundwater investigation the number of "exceedances" will depend on the number of wells and the number of sampling events per well, which would be expected to increase as DEP and DEQ engage in the iterative process of delineating the plume. (Id. at 192.) When the same well is resampled during the same day or even months later, and both results are above the groundwater standard, it does not mean that conditions have worsened. A site that samples the same well two times a year is not two times worse than if it sampled that well just once a year. (Id.) Similarly, monitoring data from new wells that were added to evaluate a known plume provides more information about existing conditions, but the data does not mean that conditions have gotten worse attributable to any fault of the Company. Witness Lucas essentially implied that the Company should be punished for meeting its CCR Rule and CAMA requirements. If the Company had not complied with the CCR Rule and CAMA by failing to install additional wells or conduct sampling in order to avoid witness Lucas's criticism, the Company would rightfully be accused of being imprudent. A catch-22 situation like this, by definition, leaves no room for a prudent alternative; therefore, the Commission finds that witness Lucas's evidence of "new" violations cannot support a disallowance under the prudence framework.

Additionally, as witness Wells, indicates, as part of that process new wells have been installed, and the location of the compliance boundary has changed, such that some wells were reclassified as being located at or beyond a compliance boundary. (Id. at 191-92.) The number of exceedances today, given the extensive groundwater monitoring required in order to comply with CAMA and the CCR Rule, says nothing about any alleged mismanagement in the past. (Id. at 192.) To the contrary, DEP's "comprehensive assessment demonstrates responsible actions that enable the Company and its regulators to better understand the impacted areas and drive appropriate corrective action." (Id. 191-92.)

Second, the Public Staff completely ignores the fact that the 2L corrective action rules are "remedial"-oriented as opposed to "compliance"-oriented. (Id. at 328-29.) The distinction is crucial to an understanding of why a 2L exceedance or "violation" is not necessarily an indication of mismanagement. But this is a distinction apparently completely lost on the Public Staff. It was explained in detail by witness Williams:

> [The distinction] is important because the class of remedial requirements, including North Carolina's 2L requirements, recognize that environmental contamination, including contamination that constitutes environmental harm, can result when an entity is in full compliance with all operational performance requirements. That is, a company may operate a facility in compliance with all waste and chemical management design and operating laws and regulations and still have releases to the environment that require either investigation or remediation under remedial laws.

> The practical reasons for this distinction are obvious. Operational performance requirements including specific permit conditions, while designed and intended to prevent environmental harm, are not fail-proof. These requirements may not adequately address all activities, all site-specific locations, all waste streams, or all chemicals with the potential to result in environmental harm. Our understanding and knowledge regarding how to achieve prospective protection is constantly evolving.

(Id. at 329.)

Third, just as with seeps, the Public Staff completely ignores the actual history of the 2L corrective action rules and their relationship to permitted facilities, like DEP's ash ponds, that predated the promulgation of those rules in 1984.[32] Pre-existing facilities were expressly addressed in connection with the establishment of corrective action requirements. (Id. at 159 (Witness Wells testified that the report accompanying the promulgation of the corrective action rules noted that "[I]t is probable that some violations do exist where facility construction predated the groundwater standards …[and that DEQ would address issues when] NPDES permits come up for renewal …").) And, indeed, groundwater monitoring requirements at a number of the ponds were addressed in the NPDES permitting process. (Id. at 165-66.) After 2008, DEQ "began systematically adding groundwater requirements to NPDES permits as they were reissued or modified" (id. at 163), and then "[a]s additional data became available and both the Company's and DEQ's understanding of groundwater impacts matured, [DEQ] issued a policy memo, dated June 17, 2011, titled 'The Policy for Compliance Evaluation of Long-Term Permitted Facilities with No Prior Groundwater Monitoring Requirements.'" (Id. at 163-64; *see also* Hart Ex. 12 (2011 DEQ Policy or Policy).)

The 2011 DEQ Policy was described in detail by witness Wells. (Tr. vol. 19, 163-64.) As he indicated, the Policy included a detailed flow chart dictating the steps to be taken by the Department and the permittee (i.e., the utility) upon the identification of a groundwater exceedance near a coal ash pond, including (1) verifying the accuracy and significance of the results of the groundwater testing; (2) determining whether and to what extent the identified substance could be naturally occurring; and (3) evaluating other possible sources of the identified substance. After these steps had been completed, and after DEQ and the affected utility had determined that the exceedance was from an ash pond, the Policy required the parties to work together to develop a corrective action plan. Notably, the Policy itself indicates that enforcement action by DEQ – the issuance of a Notice of Violation, along with fines and penalties for non-compliance – would ordinarily be unnecessary unless the permittee was uncooperative through the process described in the flowchart. This underscores the "remedial" orientation of the 2L Rules. (Id.)

In this case, witness Wells testified that

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[32] While the 2L Rules themselves first came into being in 1979, their corrective action requirements were introduced in 1984.

> Impacts to groundwater around ash basins are not the result of mismanagement. The existence of groundwater exceedances at or beyond the compliance boundaries at these sites is a function of where these sites are on the timeline of groundwater assessment and corrective action under modern laws that have changed the way that unlined basins are viewed. As these views have changed, the Company has taken every action required by … [its environmental regulators] to address groundwater impacts as they have been identified.

(Id. at 184.) He presented similar testimony in the Company's prior case. (2018 DEP Rate Order, at 174.)

Just like with seeps, the Commission heard all of this evidence in the Company's prior case. (2018 DEP Rate Order, at 181-83.) The Commission indicated that witness Wells "concluded that compliance with this process is not mismanagement and should not be held against DEP with respect to cost recovery." (Id. at 182.) It credited his testimony and expressly found that there was "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." (Id. at 183.)

CCR Costs sought for recovery in this case were expended in order to comply with requirements of CAMA, including its 2016 amendment, and the CCR Rule. CAMA and the CCR Rule are very prescriptive, and require the Company to take specific steps spelled out in their text in order to be in compliance. The Company's coal ash basins are required to be closed under these requirements. Witness Lucas asserts that "ultimate closure of all coal ash basins" will correct "environmental violations" (Tr. vol. 15, 1443), but the only "violations" the Public Staff identifies are surface water discharge requirements (allegedly violated by seeps) and exceedances under the 2L Rules. However, witness Junis fails to show any causal connection between the alleged surface water discharge violations or the exceedances and basin closure, because there is no causal connection. As witness Wells testified, "Under the CCR Rule and CAMA, closure of all of the Company's ash basins had already been triggered before the 2017 Rate Case was filed and the triggering factor was not groundwater impacts." (Tr. vol. 19, 191.)

The trigger for basin closure came either from CAMA directly or as a result of the CCR Rule's location requirements. CAMA and the CCR Rule are, of course *new* regulation – they did not even exist, nor did their triggering requirements, prior to 2014-15. Witness Bednarcik discussed the CCR Rule's triggering location criteria extensively during her cross-examination by the AG. (*See*, *e.g.,* Tr. vol. 12, 297-98 (closure required if the basin did not meet even one of the criteria); Tr. vol. 13, 21-22 (purpose of the criteria was to evaluate whether closure was mandated); id. at 24 (DEP did not meet the location requirement, so closure triggered).)

Witness Bednarcik noted further that the Company's ash basins were all lawfully permitted when first developed, and had been subject to permit renewals since they were first developed. (Id. at 68-69.) But, with the passage of the CCR Rule and CAMA, the Company was required to – and did – shift its ash management practices to comply with the new laws: "New change, new rule, new regulations. We have to comply with the new rules and regulations, and that is what we are doing." (Id. at 69.) She indicated further that basin closure resulting from the new legal requirements does not mean that past practices were unreasonable or imprudent. (Id.)

There is also no causal connection with respect to the groundwater treatment systems the Company has been required to install to meet the prescriptive requirements of CAMA/CCR Rule, pursuant to agreement with DEQ. Had the Company been able to proceed under the 2L Rules alone, natural attenuation of the groundwater plume would have been a remediation option (Tr. vol. 19, 585-86; *see also* Tr. vol. 20, 26), and a considerably less expensive one. Under CAMA/CCR Rule, as opposed to the 2L Rules alone, basin closure is required – not because of any mismanagement, but because of the mandates written into CAMA and the CCR Rule by the General Assembly and EPA.

The dissent in the 2018 DEP Rate Order recognized the lack of any causal connection as well:

> Had the Company's management of coal combustion wastes resulted in no exceedances of the state's 2L groundwater standards, no violations of any NPDES permits, no criminal prosecutions, and no civil or administrative lawsuits, the record taken as a whole shows that the Company would eventually have been required to undertake many or even most of the ash disposal activities now required of it by the CCR Rule and CAMA.

(*See* 2018 DEP Rate Order, Commissioner Clodfelter concurring in part and dissenting in part, at 9.) For example, prior to the passage of CAMA and the CCR Rule, DEP was coordinating with DEQ to develop a closure plan for the Weatherspoon ash basin, which would serve as a template for future ash basin closures at retired plants. (Tr. vol. 19, 34.) This process was underway well before any corrective action plans were developed pursuant to the 2L Rules and 2011 DEQ Policy. The lack of a causal connection means that the Public Staff cannot show that any of the CCR Costs sought for recovery should be disallowed because of "environmental violations."

During her direct examination, witness Bednarcik was given a homework assignment – to determine whether it was possible to break out the costs necessitated under CAMA and/or the CCR Rule for 2L rule exceedances beyond the compliance boundary. Witness Bednarcik did her homework and reported back when she was on the witness stand in the rebuttal phase of the hearings. The answer was that it was not possible – because what would have been required by DEQ in the absence of CAMA and the CCR Rule, and operating just under the 2L Rules, is unknowable because DEQ has wide discretion, and the Company simply does not know what would have been required under 2L alone. (Tr. vol 18, 48-50.) She concluded "Where we sit today is we have to comply with CAMA and CCR" (id. at 50) – the prescriptive rules and regulations that now govern what the Company must do and when it must do it.

In DEP Late-Filed Exhibit No. 8 the Company reiterated that it is not possible to isolate outside-the-compliance-boundary costs. Noting the prescriptive nature of CAMA and the CCR Rule, and that the 2L rule provides DEQ with considerable discretion in connection with groundwater corrective action, the Company stated "[i]t is unknown if the Company would have had to install the same number of wells, would have had to conduct the same type of groundwater modeling, or would have had to perform the same type of corrective action within the same time frame under 2L only." (Id. at 3.) The Public Staff already knows this, and witness Lucas's own testimony reflects that it knows this. He stated that 2L rule costs "***cannot be quantified without undue speculation***." ((Tr. vol. 15, 1444) (emphasis added).)

The questions for the Commission regarding the 2L Rules are identical to the questions regarding seeps: (1) whether the existence of seeps constitutes mismanagement, and, if so, (2) whether and to what degree the Company's incurred CCR costs have been impacted by that mismanagement. The answer to the first question was and still is, No. Even if the Commission answered Yes to the first question, the Public Staff has once again failed to provide evidence to resolve the second question.

Discussion of Question #2: Viewing the Company Historical Actions and Decisions Through the Prudence Framework

The prudence standard requires a detailed and fact intensive analysis into the challenged conduct. This analysis necessarily involves detailed inquiry into industry standards, inasmuch as conduct that conforms to the standards of the industry as a whole can hardly be deemed to be imprudent. The analysis also requires quantification of impact, inasmuch as cost disallowance requires quantification – without quantification there is no proven actual dollar amount the Commission may disallow. Under the prudence standard, the Company is entitled to recover the entirety of its CCR Costs. DEP has shown that its expenditures were reasonable and prudent.

Here, the challenges mounted by the Public Staff, the AG, and Sierra Club[33] all fail under the prudence standard. First, DEP has shown that its historical coal ash

[33] In addition, CUCA witness O'Donnell contends that the Company "caused" CAMA and therefore the Commission should disallow ash basin closure costs "associated with any plant that is not subjected to CCR but is subjected to CAMA." (Tr. vol. 14, 178.) Witness O'Donnell's recommendations rest on: (1) a "financial analysis" comparing the size of the CCR/CAMA ARO established by DEP with the CCR AROs established by utilities around the country and (2) a draft preamble to a prior Senate bill draft of CAMA. We previously considered and rejected these precise arguments in DEC's last rate case. In rejecting these arguments, the Commission found that "the notion that the Company was the direct cause of CAMA is of limited legal basis. Witness O'Donnell presents no evidence of such direct causation, and witness Wittliff appears to base his opinion on a draft preamble to the Senate bill (Tr. vol. 11, 240, 248-50), notwithstanding the fact that this preamble is not present in the final ratified bill. (*See* 2018 DEC Rate Order at 271.) Under North Carolina law, legislative intent is ascertained by the plain words of the statute. *Rhyne v. K-Mart Corp.*, 149 N.C. App. 672, 562 S.E.2d 82 (2002). If the legislature intended on denying cost recovery, it would have said so. Furthermore, the Commission also explained that even if DEC or DEP directly caused CAMA "such direct causation alone is not sufficient legal basis for disallowing otherwise recoverable costs." (Id. at 272.)

management practices met or even exceeded industry standards. Further, while no intervenor has shown such historical imprudence, even if there were any, no intervenor has been able to quantify the impact of such conduct upon and in relation to the CCR Costs actually incurred by the Company in the September 1, 2017 through February 29, 2020 period – a period long after any alleged (but still unproven) imprudence could have occurred.

Viewing the evidentiary record through the lens of the prudence framework, including industry standards – as the Commission must do, as there is no other lens through which to view it – answers the cost recovery issues presented in this case just like it answered them in the Company's prior rate case. This goes well beyond intervenors' failure to quantify costs, although that failure alone would justify rejection of their disallowance claims. In addition to intervenors' failure to quantify, DEP is entitled to recover CCR Costs in this case because it has proven that it acted reasonably and prudently throughout the pre-CAMA/CCR Rule period upon which intervenors center their "fault" based attack on the Company's conduct.

In addition, the Commission has not lost sight of the fact that it has heard all of this before, and already decided these issues. In the Company's prior case the Commission noted the limitations inherent in the Public Staff's approach were:

> D]emonstrated by … [witness Lucas's] inability to answer with any specificity on cross-examination: 'From 1920 until 2014, with respect to ... [the] Company's ash basins in this state, what should we have done differently and when should ... [it] have done it?" (Tr. Vol. 19, p. 35.) His response essentially was that "Somewhere along the line the Company should have taken some kind of action to not contaminate groundwater." (Id. at 36.) But the kinds of actions he appears to have favored – such as lining ash ponds when this was contrary to standard practice, or creating dry coal ash basins when for the most part the Company's industry peers were sluicing coal ash into wet basin impoundments, would (a) have cost money which would have been charged to customers, or (b) would have left the Company open to credible claims of "gold-plating," and therefore cost disallowance, which would have prevented the Company from moving forward with these suggested improvements in the first place. Witness Lucas and the Public Staff fault the Company for not taking steps that were not in accord with steps most of the industry was following, but at the same time disregarding responsibility of paying for that which they – in 20/20 hindsight – wish the Company had done.

(2018 DEP Rate Order, at 183.) The Commission also noted these same limitations in the prior DEC case (*See* 2018 DEC Rate Order, at 301), and held that it was therefore "not persuaded … that any past violations by DEC, or many of its past coal ash management practices, support the discrete amounts of cost disallowances advocated by the intervenors and the Public Staff in this case." (Id. at 302.) Nothing intervenors have submitted in this case moves the needle from the manner in which these same issues were decided in the prior cases.

Quantification of Impact

Under the prudence framework, the challenger to cost recovery discharges its burden of production by presenting evidence that quantifies the effects of allegedly imprudent actions, omissions, or decisions. (Dominion Order, at 129.) The Public Staff openly concedes an absence of any quantification and seeks only to allocate a disallowance premised upon a theory of "equitable sharing." Sierra Club and the AG have in this case attempted to quantify impacts. However, the Commission rejects their quantification theories.

Sierra Club's quantification evidence was submitted by witness Quarles. He testified that current costs would be smaller had the Company instituted dry ash handling sooner. (Tr. vol. 14, 613-14.) He indicated that the Commission need only "pick … [the] point in time" in the past when that conversion should have occurred (id. at 748), and then calculate the savings based upon a per ton cost for closing the Company's basins. But, he conceded, the per ton handling cost he used in his calculation is at *today's* cost (id.), and he had "no idea" what the costs would have been at his "pick a date" point in the past. (Id. at 750.)

Moreover, the Commission dealt with this precise issue in the Dominion Order. Noting that no party in that case presented evidence as to what CCR costs, if any, "might have been avoided if [Dominion] had used a different approach to managing its CCRs at some point during the last several decades," the Commission observed:

> For example, one could argue that [Dominion] should have converted all of its coal-fired plants to dry ash handling at least at some time during the 1990s. However, to quantify the costs and benefits of this strategy would require establishing, with some level of certainty, the costs that [Dominion] would have incurred for such conversions, and the savings in present CCR remediation costs that would have resulted from such conversions. In addition, [Dominion] could have been entitled to recover those conversion costs, plus a return on its increased rate base, from its ratepayers over the past several decades.

(2020 Dominion Rate Order, at 129.) Witness Quarles did not establish with *any* "level of certainty" what the past costs would have been; he simply had "no idea" of their magnitude. He also did not factor in the capital costs, and the Company's earnings thereon, in connection with the dry ash conversion which he states should have occurred at his "pick a date" point in the past. (Tr. vol. 14, 747-48.) The Commission has already rejected his approach.

The AG's quantification attempt, through witness Hart, also fails. First, witness Hart advocated multimillion-dollar disallowances through what he termed his "time value of money" quantification method. His methodology, which enjoys no support whatsoever from any peer reviewed authority (*See* Hart DEP Cross Examination Ex. No. 10, at 76, 88), fails to quantify any impact of supposed imprudence upon customers, because it merely shows at various earlier points in time costs equivalent to current CCR Costs, meaning that the "difference" in cost under his methodology is actually zero. (Tr. vol. 11, 163.)

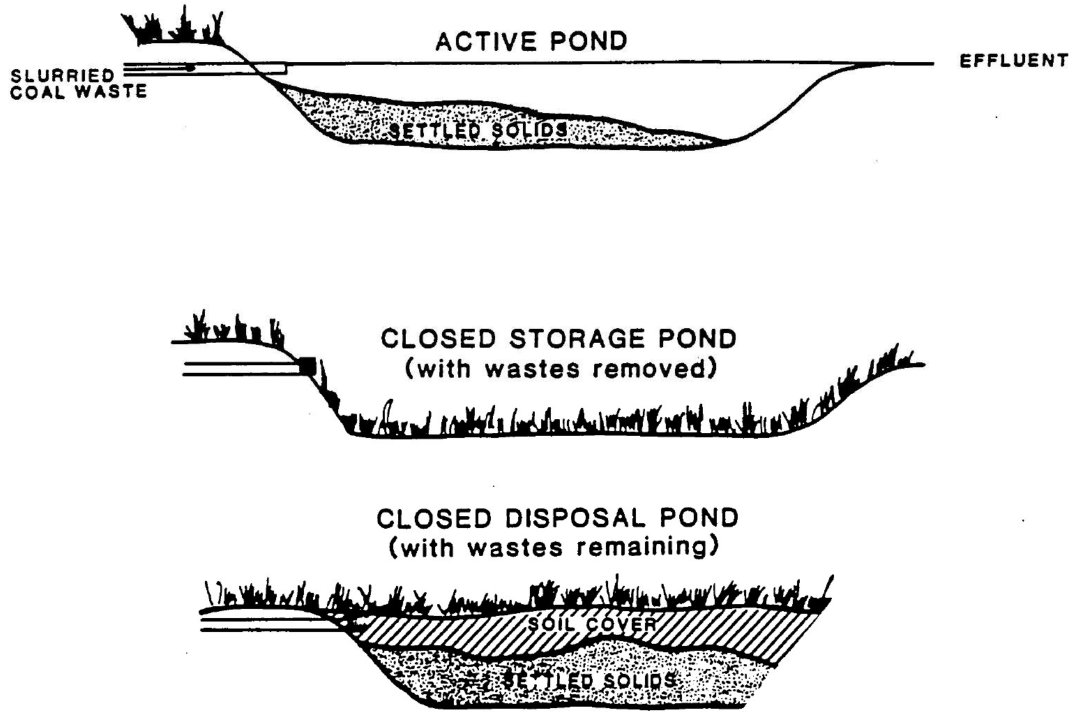
Witness Hart also advocated cost disallowance for what he called "old" basins, which he characterized as having been taken out of service many years ago but not closed; he called this disallowance "Step B." (Tr. vol. 13, 546-47.) Step B applies to inactive basins at the Company's Asheville, Cape Fear, H.F. Lee, Roxboro, and Sutton facilities. (Id.) There are multiple issues with witness Hart's Step B. First, he assumes that the inactive basins were not in use – but, to the contrary, they were (and, if still unexcavated, are) in use, if for no other reason than to store coal ash, a byproduct of the generation of electricity.

Witness Hart assumes further that the inactive basins should have been "closed" (id. at 895-96) at some point in time in the past (Tr. vol. 14, 24), although he cannot say what exactly should have been done to "close" them, nor can he define exactly when they should have been "closed." He therefore fails to take into account the fact that DEP's practices with respect to the inactive basins conformed to industry standards. (Tr. vol. 19, 323-24.) Witness Williams testified that the 1988 EPA Report to Congress, which her office prepared, described the life cycle of an ash basin, and even depicted it as shown below. (*See* Joint Ex. 13, at 4-11 – 4-12.)

4-12

EXHIBIT 4-2

TYPICAL SURFACE IMPOUNDMENT (POND) STAGES



Witness Williams noted that the final picture was of a "closed disposal pond with waste remaining in it … end[ing] up with soil over the filled solids and then some type of vegetation that ends up growing." (Tr. vol. 19, 710.) She characterized this closure method as "pretty much the standard approach at the time" (id.),[34] and witness Wells noted that with regard to "closure and treatment of those ponds over time," DEP adhered to industry standards throughout the timeframe in which it operated coal ash basins. (Id.)

Moreover, witness Hart failed to consider any costs associated with earlier closure of the inactive basins, at whatever undefined time in the past he posits they should have

[34] *See also* Joint Ex. 8 – a 1982 publication by the Electric Power Research Institute (EPRI), so, according to Intervenors, representative of "industry" knowledge and practice (*see* Tr. vol. 14, 600-01 (witness Quarles); Tr. vol. 15, 1476-79 (witness Lucas)). The EPRI report states: "The most common closure practices employed for retired utility waste disposal sites are (1) covering with soil followed by revegetation; (2) pond draining and backfilling with soil; and (3) pond abandonment." (Joint Ex. 8, at 8-1.)

been closed. Just as earlier conversion to dry ash handling would have required the Company to incur costs that it would have recovered, and upon which it would have earned a return, so too any closure involving (for example) an engineered cap (*See* Tr. vol. 14, 25) would have involved costs upon which the Company would have earned a return. Witness Hart also did not consider the impact of having to re-do any earlier closure. There is simply no evidence that any earlier closure would have obviated the need for the Company to incur the costs that it is currently incurring in order to comply with the new legal requirements of CAMA or the CCR Rule.

By itself, intervenors' failure to quantify costs and failure to account for the Company's incurrence of other costs (and earnings thereon) means that even were the Company's past actions to be deemed imprudent, no disallowance is appropriate. [35] But in addition, the Company has shown that its historical actions were not imprudent.

Industry Standards – Unlined Ash Ponds

Industry standards are the touchstone for prudence. As we have seen, prudence is an attribute of "Good Utility Practice" (Lesser & Giacchino, at 40), and "Good Utility Practice" includes "the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period" (Id. at 40.) That is, Good Utility Practice – prudence – is judged in relation to the utility's conformance with industry standards. DEP's continued operation of unlined basins until the change in law wrought by CAMA and the CCR Rule was compliant with industry standards. The Company proved this through the testimony of witness Williams, among others:

> [I]n evaluating whether a company operated reasonably it is certainly appropriate to compare that company to others in the same or similar industries. … EPA's 1988 CCR Report to Congress found that of the 483 CCR surface impoundments in the United States less than 10% (45) were found to be lined and of the 195 surface impoundments in the Southeastern United States (EPA's Region 4), less than 2% (3) were found to be lined

(Tr. vol. 19, 282.) Witness Williams' observation is further buttressed by the testimony of witness Bonaparte, who demonstrated that the Company, consistent with its peer utilities in the Southeast, managed coal ash in unlined surface impoundments throughout the pre-CAMA/CCR Rule period. Witness Bonaparte's investigation was presented through a

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[35] In the prior DEC case, the Commission discussed at length the Intervenors' often contradictory recommendations regarding what DEC should have done differently in the past. (2018 DEC Rate Order, at 316-18.) It stated that, as a result, "insurmountable obstacles exist[ed] to quantify the alleged offsets that are a fundamental element to Intervenors' disallowance theory." (Id. at 318.) Noting further that the Public Staff, "the agency required by statute to audit rate requests and recommend adjustments," candidly admitted that it was unwilling to speculate about what should have occurred in the past, and what that would have cost, and concluded "[w]ithout any evidence sponsored by any witness quantifying what DEC should have spent in the past, the Commission has no basis for disallowing 2015-2017 DEC remediation costs in support of a theory that DEC should have done more prior to 2015." (Id.) Precisely the same observations may be made concerning the 2017-2020 costs the Company has expended and seeks recovery of in this case.

report (Geosyntech Report, Bonaparte Ex. 2) which found that over 90% of the CCR impoundments "were either directly reported or interpreted to be unlined" and that most of them were reported as being active in the timeframe of the investigation (2009-11). (Id., at 9.) After obtaining approval from DEQ, the Company last constructed an unlined basin in North Carolina in 1985[36] (Tr. vol. 15, 100). DEQ approved the construction of the unlined basin at Cape Fear *after* it had required DEP to construct a clay-lined basin at Sutton in 1984 due to site-specific concerns at that site. (Id. at 153.) Even factoring in the clay-lined basin at Sutton, nearly 100% of the pre-1985 basins in North Carolina, South Carolina, Georgia and Virginia were unlined. (Bonaparte Ex. 2.)

No intervenor credibly argued that the Company deviated from the practices of the utility industry as a whole. Indeed, the AG's coal ash witness in the last round of cases "testified that the majority of utilities continued to use unlined wet ash impoundments even after this timeframe, because '[t]he law allowed them to do it, and the law continued to allow them to do it.'" (2018 DEC Rate Order, at 267.) That same AG witness, when asked how DEP's management of ash ponds was different from industry standards, testified, "Well, I think there were a number of companies that were doing exactly what Duke did." (Tr. vol. 15, at 112-13 (E-2, Sub 1142).) He went on to testify that the industry "standard, is compliance" with the law. (Id. at 114 Witness Quarles in the Company's previous case testified to the same effect. (DEC Quarles Cross Examination Ex. 1, at 199 (utilities continued to use ash ponds because it was "convenient and there [was] no regulatory standard" prohibiting the practice).)[37]

EPA promulgated the CCR Rule in 2015, and that Rule (along with CAMA) dictated closure of the Company's unlined basins. EPA issued its proposed rule in 2010. The proposed rule contained three regulatory options – regulation under Resource Conservation and Recovery Act (RCRA), Subtitle C, which contains EPA's hazardous waste rules and would have required liners; regulation under RCRA Subtitle D, the solid waste rules, which would have allowed existing ponds to operate "as is" for five years (i.e., without liners); and under an approach called "D Prime" which would have allowed unlined basins to continue to operate for the remainder of their useful lives. (Tr. vol. 20, 14.) Reviewing these options, witness Williams – with "an almost 50-year career centered on environmental protection and regulation, spanning government service with the EPA (over 17 years), a senior management position in the waste management industry (approximately 3 years), and consulting work (almost 30 years) in which … [she has] been a consultant to both private industry and government agencies on a wide range of environmental matters" (Tr. vol. 19, 205) – testified "So even as late as 2010, when EPA was putting out its proposed rule on this, it had not yet determined that it was necessary

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[36] Design documents for the 1985 Ash Basin at Cape Fear show that the basin was actually designed in 1984. (2006 Five-Year Independent Consultant Inspection, Cape Fear, Docket No. E-100, Sub 23A (filed on Dec. 4, 2008).)

[37] This exhibit contains testimony from the prior DEP rate case. The Commission has taken judicial notice of coal ash-related testimony and exhibits from that case, and the exhibit was in any event introduced into the Record in this case by way of the Amended Stipulation. (*See* Tr. vol. 14, 710.)

across the board to close unlined ponds prior to the end of their useful life …." (Tr. vol. 20, 14-15.)

Witness Williams indicated that liners in connection with the construction of ash ponds was a "site specific issue" until the CCR Rule was finalized. (Id. at 15.) The liner installed in 1984 at DEP's Sutton Plant demonstrates this – and demonstrates also that DEP was responsive to potential environmental impacts of its operations, even when those operations were ultimately shown *not* to be the cause of a perceived environmental issue.

The Sutton clay liner is the subject of extensive testimony from witness Wells. (Tr. vol. 19, 152-58, 718-20.) In summary, the issue at Sutton related to high chloride (i.e., salt) concentrations discovered in production wells operated by a neighboring manufacturing facility, Hercofina. When investigated by DEQ in 1978, the high chloride concentrations were viewed as being associated with the Sutton cooling pond, not the ash pond (Old Basin), a view that ultimately proved to be correct. (*See* Hart Ex. 24B at PDF p. 105; Tr. vol. 19, 153, 719-20.) At the time, the intake for the cooling pond in the Cape Fear River was in a location with a large tidal influence, which brought saltwater into the cooling pond. (Tr. vol. 19, 719-20.) In the late 1980s the Company moved the cooling pond intake several miles upstream, and, with fresher water drawn into the cooling pond, the chloride issue dissipated. (Id. at 154, 720.)

Nevertheless, when DEP proposed the construction of a new ash pond at Sutton in the early 1980s, Hercofina again raised the issue of potential contamination from the ash pond. DEP had by then obtained regulatory approval for construction of an *unlined* basin, but, in conjunction with DEQ, it agreed to construct the new basin with a clay liner. (Id. at 153.) To further assuage Hercofina's concerns, DEP also agreed to establish existing groundwater quality prior to construction of the new basin, and groundwater wells were installed for this purpose in 1984. (Id. at 153-54.)

In sum, DEP implemented in 1984 a groundwater monitoring program at Sutton and installed in conjunction with DEQ a clay liner at the new Sutton ash basin to address an environmental issue that actually arose not from the plant's Old Basin but from its cooling pond. But it did so in recognition of a potential future risk from the new basin, in light of concerns expressed by its neighbor, Hercofina. (Id. at 720.) Importantly, however, DEQ did not require DEP to take any action regarding installation of a liner at either the Old Basin or any of its other existing basins (id. at 154) or at a new basin that DEP constructed at its Cape Fear plant in 1985 – a year after the new basin at Sutton was built. (Tr. vol. 18, 23; Tr. vol. 19, 156.) The Sutton clay liner story illustrates both that CCR and its management is a site-specific issue, that DEP was attuned to potential for environmental degradation, and that DEP with its environmental regulator, DEQ, responded appropriately to that potential.

Accordingly, when intervenors fault DEP for continuing CCR management in unlined ponds and not switching to dry ash handling earlier, they must contend with DEP's conformance with industry standards in continuing to operate the ponds – and they do not. In addition, intervenors fail to quantify any impacts. The fact that the 1984 ash basin at Sutton was constructed with a clay liner did not prevent that basin from being excavated in the aftermath of CAMA and the CCR Rule. (Tr. vol. 15, 1718-19.) Intervenors have presented no evidence suggesting that even if the Company's ash basins had been lined when constructed, or retrofit with liners after construction, the presence of liners would have made any difference to the basin closure activities – and their attendant cost – that the Company has had to undertake post-CAMA and the CCR Rule, in order to comply with the new legal requirements of CAMA and the CCR Rule.

<u>Industry Standards – Groundwater Monitoring</u>

Intervenors contend that the Company engaged too late in "comprehensive" (Lucas – Tr. vol. 15, 1480-81) or "proactive" (Hart – Tr. vol. 13, 541, 690-91) groundwater monitoring at its coal ash basins. Intervenors have once again supplied their own vague, subjective standards in place of objective, industry standards.

Witness Williams unequivocally testified that DEP was well ahead of its industry peers in initiating and conducting groundwater monitoring at its coal ash ponds. She summarized the evidence supporting her observation during the DEC-specific hearings, noting that "[F]rom the '80s all the way through to the time frame when EPA was doing its proposed rule, you were seeing numbers like 33 -- 32 percent, 33 percent, 35 percent of these facilities had groundwater monitoring installed, and so I think it really is noteworthy that by the time you get to 2008, you know, when Duke had completed installing initial well systems at all of its facilities that hadn't already installed them due to a requirement in an NPDES permit, they installed it at the rest of the facilities by 2008." (Tr. vol. 19, 624-25.) In the DEP-specific hearings she added:

> So I would just say, if you want to compare both to what EPA knew and to what industry practices were, I'm not going to repeat all the statistics that I put on the record in the DEC case, but unlined ponds were the most prevalent and common type of pond that was in use throughout the 1980s, well into the 2000s at the time of the CCR final rule. ***And that DEP was ahead of the curve, in terms of industry standards, of starting its groundwater monitoring, before it was required, before the majority of the industry had it at all sites. And DEP did begin undertaking coordination with DEQ to react to the results of the groundwater monitoring. I think they were a leader in this particular situation.***

(Tr. vol. 19, 704-05 (emphasis added).) No witness in this proceeding had the depth of knowledge and expertise on the subject of groundwater regulation possessed and displayed by witness Williams. She stated, regarding DEP's groundwater monitoring program, "I believe in light … of the fact that [DEP] had installed groundwater monitoring systems before many of the industry had done it at all their facilities and were then improving them and working with them, I believe they did what you would reasonably expect a prudent utility to do." (<u>Id</u>. at 654.) The Commission agrees with witness Williams that DEP demonstrated leadership and exceeded industry standards in implementing its groundwater monitoring regime, and that these are attributes of a prudently managed and operated utility.

EPA never required groundwater monitoring at any coal ash pond until it included a monitoring requirement in the CCR Rule – in 2015. (Id. at 440.) Likewise, DEQ never required DEP to monitor groundwater at every ash basin; DEP undertook that responsibility voluntarily. While intervenors portray DEQ as passive and credulous, the regulatory history between DEP and DEQ revealed through the record paints a vastly different picture. As witness Wells notes,

> Throughout its history of CCR management, the Company has worked in lock-step with its regulators to site, construct, and operate ash basins in compliance with regulatory and industry standards. When deemed necessary to address environmental conditions at its sites, the Company coordinated with regulators to develop a remedial response, including further groundwater monitoring and assessment. DE Progress also participated in voluntary efforts to help the industry and its regulators better understand the potential impacts of ash basins on the environment. These actions are affirmative evidence of prudence.

(Tr. vol. 19, 135-36.)

One example was DEQ's coordination with DEP to characterize and identify groundwater impacts at the Sutton plant in the 1980s. This effort resulted in DEP's decision to construct a new clay-lined ash basin and the installation of a groundwater monitoring system that provided data for decades. (Id. at 269.) Another example was the investigation of high selenium levels in Hyco Lake that resulted in DEP's decision to convert to dry fly ash handling. (Id.) Yet another example is the groundwater investigation the Company undertook at its Mayo site, which occurred in 1978-79, in connection with the Company's analysis of environmental impacts of the plant, which was then under consideration but had not as yet been constructed. The investigation is described in a report authored in 1979 by Edwin O. Floyd, a licensed engineer specializing in groundwater hydrology and titled "Evaluation of the Potential For Contamination of the Ground-Water Aquifer By Leachate From the Coal-Ash Storage Pond at the Mayo Electric Generating Plant Site" (Floyd Report). (Bednarcik Rebuttal DEP Redirect Ex. No. 1.) The Floyd Report concluded, among other things, that the clay-rich soils at the Mayo plant site would preclude any significant adverse impact upon groundwater from the operation of Mayo's unlined ash basin:

> Soil conditions at the proposed ash pond site at the Mayo Electric Generating Plant are adequate to provide excellent protection to the ground-water aquifer both in preventing significant leakage from the pond and in reducing the concentrations of the heavy minerals by filtration before the leachate reaches the aquifer. …
>
> In consideration of the natural action of the soils on heavy minerals in the leachate, the dilution effects of mixing with the natural ground water, and the fact that there are no water supply sources or major water courses for miles downstream from the ash pond dam, ***it is difficult to imagine that***

any significant adverse impact on the ground water aquifer could be caused by ponding of the ash wastes at the proposed site.

(Id. at 14-15 (emphasis added).)[38]

More recently, the Company proactively approached DEQ in 2008 when groundwater monitoring data showed exceedances of boron at the compliance boundary. The Company took action to address concerns regarding potential impacts upon drinking water supply wells, even though subsequent investigation indicated that the Sutton ash pond was not the source of boron impacts upon those wells. (Id. at 170-71.) As with the other examples, the Sutton boron case shows that "[c]onsistent with its history, the Company took targeted action to resolve a specific [environmental] concern." (Id. at 171.)

Around 2009, DEQ began to add groundwater monitoring requirements to all of the Company's NPDES permits as they came up for renewal. As the Company's and DEQ's understanding of groundwater conditions grew as a result of the Company's monitoring efforts, DEQ realized that the regulated community lacked sufficient guidance on how to evaluate and correct groundwater impacts at long-term permitted sites like DEC's. In 2011, DEQ issued a guidance document that proscribed the process to be undertaken by DEQ and utilities upon the identification of a groundwater exceedance near a coal ash pond. (AG Hart Direct Exh. 12 (2011 DEQ Policy).) The 2011 DEQ Policy included a flowchart that "outlines the steps to be taken to assess whether or not groundwater standards have been exceeded at the compliance boundary." (Id.) Under that process, only after a utility failed to undertake corrective action when directed to do so would DEQ consider pursuing enforcement. (Id.) The mere existence of the 2011 DEQ Policy, as well as its provisions, severely undermine Public Staff's position that DEP was delinquent in monitoring groundwater at its sites. If the path for determining compliance with North Carolina's groundwater standards from 1979 to 2011 around ash basins was as clear and obvious as the Public Staff seems to suggest, then there would have been no need for DEQ to issue guidance on how to perform that evaluation. Further, had DEQ believed that DEP was deficient in instituting groundwater monitoring at its basins, then DEQ would not have restricted its ability to issue notices of violation and penalties. Stated differently, DEQ did not consider groundwater exceedances associated with DEP's ash basins to be the result of wrongdoing or mismanagement warranting punishment. Only

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[38] The Floyd Report's reference to the clay-rich Piedmont soils and their attenuative capacity is echoed by EPA's investigation of, among other sites, DEC's Allen Plant several years later. (*See* Joint Ex. 10.) The investigation was conducted through a contractor, Arthur D. Little, Inc., and the Allen Plant was selected for study inasmuch as EPA viewed it as representative of sites located in the Piedmont region (Tr. vol. 19, 161), which is where Mayo is located. (Id. at 152.) The Arthur D. Little Report concluded that "Data from the study suggest that no major environmental effects have occurred at any of the six sites." (Joint Ex. 10, at iii.) As witness Williams notes, the Arthur D. Little report concluded that the Piedmont soils prevented arsenic from migrating and impacting groundwater. (Id. at 288.) And as witness Wells testified, the Arthur D. Little report, along with DEC's own internal investigations at Allen, concluded that the wet sluicing of coal ash to Piedmont region ponds did not have a significant impact to groundwater: "And the key conclusion, not just from Duke's internal voluntary work … [but also the] A. D. Little work, was the same. And that is the impacts were localized, they weren't seeing a risk, they weren't seeing a significant impact." (Id. at 391.)

DEP's failure to correct those violations once they were identified would be deserving of punishment.

The 2011 DEQ Policy is consistent with DEQ's historical treatment and regulation of ash basins. DEQ never imposed a blanket groundwater monitoring requirement for all of DEP's sites. Instead, DEQ reserved discretionary authority in the general conditions of its NPDES permits to require permittees to monitor groundwater to determine a facility's compliance with state groundwater standards. *See, e.g.* DEC NPDES Permits and Groundwater Monitoring Reports, Docket No. E-7, Sub 1146, 152 (Mar. 12, 2018). "Part III Other Requirements" of NPDES permits issued by DEQ in 2002, for example, contained Condition "B. Groundwater Monitoring," which stated, "[t]he permittee shall, upon written notice from the Director of the Division of Water Quality, conduct groundwater monitoring as may be required to determine the compliance of this NPDES permitted facility with the current groundwater standards." (Id.) DEQ's authority to require groundwater monitoring at an NPDES facility can be found in Section .0110 of the 2L Rules, which became effective on August 1, 1989. 15A N.C.A.C. 2L .0110(a) (Lexis). Therefore, it is indisputable that DEQ had the regulatory authority and discretion to require groundwater monitoring as a condition in all of DEP's NPDES permits at any time after August 1, 1989.

For DEP's sites, DEQ exercised its regulatory discretion by *gradually* adding groundwater monitoring requirements to the Company's NPDES permits over a span of two decades, beginning in 1993. As witness Wells explained, groundwater sampling data was submitted to DEQ, and DEQ possessed the expertise to evaluate that data. DEC's groundwater monitoring plans that were submitted pursuant to NPDES permit requirements were subject to DEQ's approval. Yet, DEQ *required* the Company to monitor groundwater only at a few select sites through the 2000s. In fact, even after the 2011 DEQ Policy was issued, it was not until 2013 that DEQ included groundwater monitoring as a requirement in all of the Company's NPDES permits, despite the fact that each NPDES permit has a reopener provision. (Tr. vol. 19, 165-66.)

The Public Staff and other intervenors may wish that DEQ had taken a more aggressive regulatory approach to groundwater at DEP's sites. The Commission, though, does not have the authority to second-guess the Company's environmental regulators. Nor can the Commission conclude from the evidence that the Company's reliance on its regulators to define the scope of its regulatory requirements with respect to groundwater monitoring was unreasonable. While intervenors characterize the 2L standards as self-implementing such that DEP was obligated to actively monitor groundwater at all sites, evidence in the record contradicts this opinion. First, if intervenors' assertion is correct, then there would have been no need for DEQ to subject NPDES permittees to Condition B of "Part III Other Requirements." Second, if intervenors' assertion is correct, then DEQ would not have surrendered enforcement authority over 2L violations under the 2011 DEQ Policy. Third, intervenors fail to consider the evolution of groundwater assessment capabilities and reliability over time. Intervenors contend that wide-spread monitoring should have occurred as early as the 1980s. As Company witness Williams testified on cross examination, groundwater monitoring was in its infancy at this time, and there was no regulatory push to require facilities to drill wells all over sites to gather information that at the time was not viewed as entirely helpful to regulatory decision-making. She noted cases where groundwater monitoring wells were drilled too close to waste and ended up *causing* groundwater contamination that would not have otherwise been present. (Tr. vol. 19, 401-02.) Lastly, intervenors fail to consider that each NPDES permit issued to DEP was written by DEQ to “protect the level of groundwater quality, established by applicable standards, at the compliance boundary.” 15A N.C.A.C. 2L .0108(f)(1). As Company witness Williams testified, an environmental regulator in DEQ’s position would not have issued NPDES permits to DEP if it believed the Company’s operations posed an unreasonable risk to groundwater quality (id. at 348); nor could it have done so under North Carolina regulations. The Commission reminds intervenors that the Commission’s responsibility is cost recovery; environmental regulators must oversee protection of the environment and public health.

The undisputed evidence indicates that Colleen Sullins, who began her career at the Division of Water Quality within DEQ in 1992 writing permits for large industrial users and ended up being the Director of the Division of Water Quality in 2007 before retiring in 2011, testified that “Coal ash has been an issue that I dealt with for most of my career at the Division of Water Quality.” (DEC Hart Cross Examination Ex. 4, at 22.) And the reason is obvious:

> [T]he power companies [meaning DEC and DEP], we were constantly in interaction with them because we were issuing permits for them to do a variety of different things.
>
> So you know, they were sort of always on the radar like a large, a large permitted entity would be and a complex permitted entity because it involved multiple divisions trying to figure out how to issue the various permits for which they had responsibility and deal with the various issues.

(Id., at 30.) Every single one of DEP’s coal ash basins was permitted by DEQ, and those permits constantly came up for renewal on a periodic cycle. To portray DEQ as disengaged is to twist the facts into an unrecognizable shape, far removed from reality.

Alternatives – Early Ash Pond Closure

The prudence framework demands a comparison between viable alternatives; without that comparison, the Commission is not in a position to assess whether the alternative chosen was imprudent. In addition, quantification of effect cannot be ascertained without a comparison of alternatives, since the disallowance must be calculated as the difference between the (presumably) higher cost imprudent alternative and the (presumably) lower cost prudent alternative.

Intervenors posit that regulatory closure of ash basins at an earlier (although undefined) point in time might have lessened current CCR Costs. Of course, “might have lessened" is not quantification.[39] In addition, wet sluicing of coal ash is the lowest cost option. (*See* DEP Late-Filed Ex. 21, at 1.) Accordingly, had the Company embarked prematurely upon dry ash handling at its facilities it would once again have opened itself up to "credible claims of 'gold-plating,' and therefore cost disallowance" (2018 DEP Rate Order, at 183), particularly in light of the Company's own conclusion – concurred by DEQ – that no significant impact from the basins existed, in light of EPA/Arthur D. Little's identical conclusion (Joint Ex. 10, at iii), and in light of EPA's conclusion that existing coal ash management techniques were adequate. (Joint Ex. 13, at 7-11.)

Nevertheless, responding to site-specific conditions, the Company did undertake dry ash conversions in limited circumstances. At its Roxboro facility it converted to dry fly ash handling in the late 1980s, in order to address surface water impacts to Hyco Lake (see Tr. vol. 19, 178); DEC did so too at its Belews Creek facility in the same timeframe and for essentially the same reason. (Joint Ex. 11.) This is an example of the Company acting proactively and prudently as warranted by evidence of environmental impact from its operations. (Tr. vol. 19, 686.) Dry fly ash handling capability was implemented at Mayo in order to take advantage of opportunities to sell the ash commercially (Bednarcik Rebuttal Sierra Club Cross Examination Ex. No. 2 (Mayo EIS), at 6-12.)[40] But in the case of both Roxboro and Mayo, bottom ash continued to be handled wet – because wet sluicing was not perceived to be an environmental risk, and because wet sluicing was not only the low cost option but also an entirely legal option.

Prior to approximately 2010, the prevailing assumption in the utility industry was that coal-fired power plants would continue to supply power long into the future, on the order of 55 to 65 years. (Tr. vol. 17, 49-50.) In the 2009-11 timeframe, electric utilities with coal-fired plants were evaluating potential retirement of those plants because of tighter environmental regulation coupled with the falling price of natural gas. (Id.) The Company participated in this re-evaluation – as did the Commission itself. (*See* DEP Late-Filed Ex. No. 3.) In this Exhibit, DEP recounts the history of its planned retirements of coal units at its H.F. Lee, Cape Fear, and Weatherspoon plants in connection with the Commission's approval of a CPCN for a new 950 MW Wayne County Combined Cycle Project (Lee CC). These retirements were prompted by extensive analysis showing that required environmental controls at these units would be uneconomical and that retirement was the more cost-effective, and hence more prudent, path.

The Exhibit also notes the Company's request for – and the Commission's approval of – the retirement of Sutton coal units in connection with the development of a replacement 620 MW combined cycle plant at Sutton (Sutton CC). Again, retirement was

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[39] The same factors that the Commission pointed to in the 2020 Dominion Order would also apply. To support a disallowance, the Commission would need evidence of savings resulting from early closure netted against the costs that would have been incurred in early closure, including cost recovery plus a return on DEP's increased rate base.

[40] The Mayo EIS further demonstrated that wet fly ash handling was considerably cheaper than dry handling, with dry handling shown to be more than twice as expensive. (Mayo EIS at 6-12; Tr. vol. 19, 682-83.)

the more cost-effective and more prudent path, as opposed to installing newly required pollution control equipment.

The retirements all took place during the 2011-13 timeframe. Intervenors suggest that had ash basin retirement occurred in conjunction with plant retirement, costs might have been lower – although, once again, they do not quantify "lower." But this notion also runs up against the "viable alternative" factor embedded in the prudence framework. In North Carolina, pre-CAMA and pre-CCR Rule, despite years of trying, the DEQ had simply not come up with closure rules, standards, and regulations.

The evidence of this is again completely undisputed, and was testified to at length by Company witness Jessica Bednarcik. (*See* Tr. vol. 13, 61-63; Bednarcik Direct Redirect Ex. 3 (Redirect Ex. 3); Bednarcik Direct Redirect Ex. 4 (Redirect Ex. 4).)

Redirect Ex. 3 is a memorandum memorializing a July 23, 2009 meeting between DEQ, DEP, and DEC regarding ash ponds. It starts out by indicating that DEQ had so far that year "received and responded to many questions from the media and the public about ash ponds," and that DEQ "staff had commended the utility companies for volunteering this groundwater monitoring program[41] and maintaining a productive working relationship with the agency." (Id. at 1.) The memorandum indicates that while DEQ had some pond closure requirements, they were "light on specifics" and that its two relevant subdivisions "would get together internally to discuss closure requirements for ash ponds." (Id. at 2.) It indicates further that DEQ did not state a timeframe by which it "would issue closure requirements for ash ponds." (Id.)

Redirect Ex. 4 is an email chain dated March/April 2013 between DEQ and "Duke Energy" (that is, after the merger of Duke and Progress, which occurred in July 2012). The email exchange reflects that in March 2013 DEQ sent Duke draft ash pond closure guidance developed "over the past year" and requested "feedback from our stakeholders, Duke and the former Progress Energy, before going forward with this. (Redirect Ex. 4, at 1.) The transmittal email also indicates that the DEQ draft "was based on what you [i.e., Duke] presented during our Weatherspoon closure meetings …." (Id.) The requested feedback was provided in April. (Id.) Of course, this exchange took place almost four years after DEQ had indicated, in Redirect Ex. 3, that it would come up with guidelines, although without any commitment as to a timeframe in which it would do so. As witness Bednarcik observed, this was not a "simple process" and it took "a long time … for DEQ to provide draft guidance." (Tr. vol. 13, 63.)

The guidelines were never finalized. (Id. at 64.) Instead, with the passage of CAMA and the promulgation of the CCR Rule, the General Assembly and EPA provided highly prescriptive rules for how and in what timeframe basin closure could and would proceed.

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[41] Both DEP and DEC participated in a voluntary groundwater monitoring program at all of their ash pond sites, a program coordinated by USWAG in partnership with EPA to implement a voluntary groundwater monitoring program to help federal and state regulators expand their knowledge of potential groundwater impacts from unlined ash basins. (*See* Hart Ex. 13.)

Even absent DEQ's uncertainty about closure of inactive basins, intervenors ignore that the accepted practice in the industry and North Carolina for "closing" inactive ash basins involved allowing it to decant naturally and vegetate. (Tr. vol. 19, 323-24.) The Commission has already reviewed the 1988 EPA Report to Congress' discussion of this standard industry practice above, in the section on intervenors' failure to quantify impacts.[42]

The prudence framework requires the Commission to compare alternative choices available to the Company if it is going to deem the chosen option to be imprudent. But in terms of early closure of ash ponds, closure at any time prior to CAMA/CCR Rule was not even an option, unless the Company wished to get ahead of its environmental regulator, and simply begin to close a pond without that regulator's buy-in. But that would have been imprudent – because without the buy-in, the Company had no assurance that its chosen path would have been approved by the environmental regulator. If not approved, then of course the Company would have been at risk of re-doing work – potentially very expensive work – it had already done. As witness Bednarcik stated, regulatory clarity ensures that the Company can execute its "work per our rules and regulations." (Tr. vol. 13, 65.) Prematurely executing work and finding itself in non-compliance with the rules and regulations would have garnered no sympathy from the Public Staff, the AG, or the Commission – its economic regulator.

Prematurely performing work, particularly in the timeframe after the publication by EPA of its proposed CCR Rule (Proposed Rule) in 2010 would have been even more fraught.[43] The scope of potential regulatory action set out in the Proposed Rule was very wide, so the issuance of the Proposed Rule increased, rather than decreased, regulatory uncertainty:

> The proposed rule offered regulatory options that varied significantly in how they would address existing ash ponds. One of the options would regulate CCR as a special waste under the hazardous Subtitle C regulations (the Subtitle C Option). Existing ash ponds would be required to meet similar requirements to hazardous waste surface impoundments or go through formal closure. Another option would establish standards for ash ponds under the non-hazardous Subtitle D regulations (the Subtitle D Option). Under this option existing ash ponds would also need to meet new technical standards, including composite liners, or close. However, EPA also offered a third option it called "D prime." This option was the same as the Subtitle D option, except that existing unlined ash ponds would not have to close or install composite

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[42] *See also* Joint Ex. 8 – a 1982 publication by EPRI, so, according to Intervenors, representative of "industry" knowledge and practice (*see* Tr. vol. 14, 600-01 (witness Quarles); Tr. vol. 15, 1476-79 (witness Lucas)). The EPRI report states: "The most common closure practices employed for retired utility waste disposal sites are (1) covering with soil followed by revegetation; (2) pond draining and backfilling with soil; and (3) pond abandonment." (Joint Ex. 8, at 8-1.)

[43] This of course is the precise timeframe in which Intervenors, citing retirement of coal plants, indicate that basin closure should have occurred.

> liners but could continue to operate for their existing life. Therefore, the proposal left open whether existing ash ponds would be required to upgrade or close or could continue to operate as is and whether CCR would be regulated as a hazardous waste or as non-hazardous waste.

(Tr. vol. 19, 248-49.) Had EPA chosen the Subtitle C Option, the impact – in terms of what would have had to have been done and its cost – would have been "unbelievable"; in contrast the D Prime Option would have meant the Company would "basically do nothing." (Id. at 573.) Guessing wrong could have led the Company to incur substantial costs and be subjected to second-guessing by the Public Staff, the AG, and the Commission.

The Commission addressed this very point in the Company's prior case:

> DEP in the past contemplated a future requirement to close unlined impoundments. While it was reasonable and appropriate to anticipate and plan for what EPA's ultimate decisions would be, the Commission determines not to penalize DEP through denial of cost recovery for its decision to wait until EPA's CCR determinations in this area were finalized. Had DEP acted prematurely in anticipation of regulations under consideration but not yet implemented, with the expenditure of substantial sums in the process, and with the ultimate EPA decisions differing from those anticipated, DEP risked unjustified expenditures.

(2018 DEP Rate Order, at 200.) The Commission even provided an example of how that might happen. It referenced EPA's 2015 promulgation of the Clean Power Plan, which imposed significant obligations upon the utility industry. The Commission noted that had "electric utilities incurred costs prematurely to comply, these costs could have been called into question when the U.S. Supreme Court stayed the Clean Power Plan." (Id. at 200-01.)

The danger of proceeding prematurely is also illustrated by Georgia Power's decommissioning of one of its coal-fired stations, Plant Arkwright. Closure also included the plant's coal ash ponds, which, like DEC's ponds, were unlined. The AG introduced as a cross examination exhibit a 2004 manual published by the EPRI titled "Decommissioning Handbook for Coal-Fired Power Plants" (Doss/Spanos/Riley Rebuttal AG Cross Exhibit No. 1 (2004 EPRI Manual)), which described the Plant Arkwright closure.

Ash pond closure at Arkwright was prompted not only by closure of the associated coal plant (something not contemplated for DEP plants until much later), but also by Georgia Power's desire to repurpose the plant site "for future development." (Id. at A-2.) Ash pond closure in Georgia had a defined regulatory structure, and the Georgia environmental authorities participated in the closure plan. (Id. at A-6.) Nothing similar was available to DEP in North Carolina.

But the Plant Arkwright pond closure serves as a cautionary tale, as its story was not finished in the mid-2000s. Despite the involvement of the Georgia environmental authorities in the closure, and despite the fact that Georgia had a defined regulatory structure for pond closure, Georgia Power is today having to re-do the closure, because the regulatory standards have changed from the time at which the work was originally performed. (Tr. vol. 19, 707-08.) The notion that early closure would necessarily have resulted in lower (if still undefined) cost has no basis in objective evidence and is sheer speculation.

Company witness Williams, drawing on her decades of experience, testified that in light of all the regulatory uncertainties faced by owners and operators of coal ash ponds in North Carolina, it was prudent to wait "until after CAMA and the CCR Rule became law to take specific actions to upgrade or close ash ponds as long as they were working cooperatively with environmental officials to address any site-specific environmental issues." (Tr. vol. 19, 213-14.) No intervenor witness has the credentials to credibly contradict this testimony, and no intervenor witness did contradict this testimony.

DEP did intervene and work cooperatively with environmental officials to address site specific environmental issues. Witness Wells testified, if the Company were to see a public health risk then "You move and take action. And that's what the Company has done throughout these years." (Tr. vol. 19, 384.) One example of this is the Sutton chloride situation in the mid-1980s; another is the Roxboro Hyco Lake situation; and yet another is the Sutton boron plume situation. But apart from these discrete instances the Company did not see a public health risk justifying precipitous action – and neither did its environmental regulator, DEQ. As witness Wells testified, the Company's ash basins have been actively regulated by DEQ for decades in order to "minimize potential impacts to human health and the environment," including reviewing "decades-worth of surface and groundwater data" from those basins. (Tr. vol. 19, 181.) Despite this intensive regulation, prior to the advent of CAMA/CCR Rule and their new legal requirements, DEQ never ordered DEP to cease using or close the basins, and never even took other less sweeping measures, such as requiring the Company to retrofit the basins with liners, close basins that had become inactive, or excavate coal ash from any basin, active or inactive. (Id.)

DEQ's regulatory role is ignored by intervenors. But fully appreciating that role is critical to the prudence analysis. Witness Williams testified:

> That DEQ did not require [DEP] to modify the design of its ash ponds by requiring liners, did not require the ponds to close, or did not mandate groundwater monitoring earlier than they did, is a strong indication that [DEP's] operations were considered to be reasonable and protective by the Agency charged with protecting the North Carolina environment.

(Id. at 277.) CAMA and the CCR Rule require highly prescriptive actions that the Company is compelled to take, and which it has taken. The notion that in the absence of those prescriptive requirements DEP should have taken those or similar actions earlier, and that doing so would have reduced cost, also has no basis in objective evidence and is sheer speculation.

Intervenors Rely on 20/20 Hindsight, which the Prudence Framework Prohibits, and Their Analysis Lacks Rigor, which the Prudence Framework Demands

The prudence framework expressly forbids the Commission from evaluating a utility's conduct through the eyes of hindsight, which, of course is always 20/20: "Hindsight analysis – the judging of events based on subsequent developments — is not permitted." (1988 DEP Rate Order, at 14.) Unfortunately, however, intervenors' testimony and arguments are infused with hindsight analysis.

Illustrating this point is the testimony of Public Staff witness Junis.[44] He expressed his concern, in commenting on DEP witness Bednarcik's earlier testimony (Tr. vol. 12, 242), that in her review of some of historical documents she tried to put herself in the timeframe of the documents with the knowledge available at that time, and with that mindset concluded that she would not have done anything differently at the time. He stated in response:

> [Witness Bednarcik] stated very authoritatively that, based on reviewing all of this historical documentation, that if she was in a position to decide, she would have done nothing different in the management of coal ash over that period. ***I have great concerns about a scientist or engineer looking back over decades of time and not finding one thing that could have been done better or differently.***

(Tr. vol. 15, 1726-27 (emphasis added).) This is Public Staff's philosophy – looking back, it could find all manner of things that in its view should have been done differently. But that in a nutshell is hindsight analysis. Witness Bednarcik, to the contrary, engaged in appropriate prudence review analysis – she sought to review decisions made by the Company "in light of the facts known at the time the decision was made" (Lesser & Giacchino, at 40), not looking at those decisions with 20/20 hindsight.

Witness Lucas's overall criticism that the Company should have engaged in "comprehensive" groundwater monitoring in the 1980s (Tr. vol. 15, 1480-81) is another example of intervenors' hindsight analysis; as witness Williams testified in response, it was not until "many decades later …[that we understood] that it takes a very large number of wells to truly understand the complexity of what's going on in the subsurface adequately." (Tr. vol. 19, 716.) She responded further to witness Quarles' testimony regarding groundwater monitoring standards and his criticism of what EPA and the utility industry knew about groundwater monitoring in the 1980s, noting first that she was "somewhat disturbed by his comments" (Tr. vol. 19, 701) and continuing:

> [Witness Quarles] also expressed the opinions strongly about the state of

[44] This testimony has been stipulated into the DEP Record through the Amended Stipulation, which recognized "that a question posed live in the [DEC] hearing to a witness in that hearing would be answered in like fashion by that same witness, tailored to [DEP], in the [DEP] hearing."

> groundwater monitoring and whether that monitoring was required by EPA. He didn't cite references in his response, nor were there supporting references in his testimony on that. And I would just say, again, I lived this for a very long time at EPA. And I will tell you that groundwater monitoring was very different in terms of the knowledge level in the 1980s than what it is today.
>
> And that included things like the definition of what a perched aquifer was that was defined as part of the uppermost aquifer. But it also included whether or not groundwater monitoring on a site-specific basis was deemed to be high priority and appropriate. And it was specifically deferred to the state to make those determinations.

(Id. at 704.)

Witness Williams was with EPA from 1970 through 1988. She knows exactly when intervenor witnesses are employing hindsight analysis because she was there at the time and understands and knows from her own first-hand experience what was happening at the time. Her conclusions based upon her vast experience and expertise fully support the Company's positions:

- First, that it is difficult to predict the exact nature of future regulatory requirements until a final rule has been issued.
- Second, that owners and operators of coal ash basins in North Carolina faced significant uncertainty regarding the regulatory requirements for managing CCR until the passage of CAMA and the promulgation of EPA's final CCR Rule, and even after these new legal requirements were finalized site-specific clarity for the Company was achieved until 2020.
- Third, in light of these uncertainties, owners and operators of coal ash ponds were acting prudently by waiting until after CAMA and the CCR Rule became law to take specific actions to upgrade or close ash ponds as long as they were working cooperatively with environmental officials to address any site-specific environmental issues.
- Fourth, prior to the enactment of CAMA and promulgation of the final CCR Rule, an accurate estimate of the costs associated with ash pond closure (even assuming that closure would have been required) would have been extremely difficult with a high likelihood for significant over- or under-estimation. Even with those regulations, fully known and measurable estimates required completion of recently finalized site-specific closure agreements.

(Id. at 234-35.) Intervenors simply have not presented evidence to refute witness Williams' observations; to the contrary, through her testimony the Company has met its ultimate burden of proof to show that its historical actions were prudent and do not form the basis of any cost disallowance.

Closely akin to hindsight analysis is intervenors' practice of cherry picking a sentence or two from a massive historical document or study and using that snippet of the document to "prove" a point, while ignoring the balance of the document, which typically proves the opposite. While there are many examples (more of them are reviewed below in connection with the Commission's discussion of the Company's entitlement to a return "on" CCR Costs), one that stands out is the Mayo EIS, Bednarcik Rebuttal Sierra Club Cross Examination Ex. No. 2.

After witness Bednarcik, recalling her DEC testimony, noted that intervenor witnesses "were putting [on] today's lens" when they tried to look at historical practices, and that is what she "was calling out" (Tr. vol. 17, 480-81), Sierra Club asked if she was "aware that, in 1978, at the time the Company was making decisions, EPA had clearly stated that water carriage of fly ash and bottom sluicing systems are, quote, inconsistent with existing and expected standards of performance for new sources." (Id. at 481.)

The quoted reference in the question was to a few lines in a letter within the 500+ page Mayo EIS. The prudence framework demands rigor; in the Commission's own words, a "detailed and fact intensive analysis." (2020 Dominion Rate Order, at 116; 2018 DEC Rate Order, at 258.) Cherry picking is the antithesis of rigor, and this is demonstrated by rigorous examination of the Mayo EIS itself, which the prudence framework requires.

Rigorous analysis begins with context. An Environmental Impact Statement is required under the National Environmental Policy Act (NEPA), 42. U.S.C. § 4321 *et seq.,* which "sets forth a regulatory scheme for major federal actions that may significantly impact the environment." *Nat'l Audubon Soc'y v. Dep't of the Navy (Audubon)*, 422 F.3d 174, 184 (4th Cir. 2005). The Mayo EIS was made necessary by DEP's application for a permit (404 Permit) from the Army Corps of Engineers (Corps), a federal agency, in connection with the development of the Mayo plant. The Corps was, therefore, the federal agency that prepared the Mayo EIS. The process culminated in the issuance by the Corps of the 404 Permit. (Mayo EIS, at PDF pages 1-11.)

NEPA is designed "to promote efforts which will prevent or eliminate damage to the environment and biosphere and stimulate the health and welfare of man." *Audubon*, 422 F.3d at 184. It does so in two ways – first, it requires that the federal agency in question (here, the Corps) carefully consider the effects of its action upon the environment – in NEPA parlance, that the agency take a "hard look" at the action's environmental impact. (Id. at 184-85.) Second, NEPA requires the agency to communicate widely so as to ensure that the public and other governmental agencies have the opportunity to analyze and comment on the proposed action. (Id. at 184.) To fulfill this obligation, the agency in question will prepare and disseminate a Draft Environmental Impact Statement (Draft EIS). In the Mayo Draft EIS, one of the issues identified by the Corps was a "potential risk to Crutchfield Branch" in connection with the development of the Mayo project. (Tr. vol. 19, 680.)

The entire Mayo EIS document consists of well in excess of 500 pages. Two of those pages consist of a comment letter from EPA Region IV to the Corps, commenting on the *Draft* Mayo EIS. (Mayo EIS, at PDF pages 498-99.) The snippet from the letter referenced in Sierra Club's cross-examination of witness Bednarcik came from this letter. EPA Region IV noted therein its concern, echoed in the cross-examination, regarding the potential environmental impact to Crutchfield Branch, a stream nearby the proposed location of the ash pond and into which the proposed NPDES outfall from the pond would flow.

Following receipt of comments, the next step in the NEPA process is for the Corps to review and resolve the comments, which the Corps did in connection with its preparation of the *Final* Mayo EIS. (Tr. vol. 19, 680.) Witness Williams described in detail the Corps' resolution of the EPA Region IV comments. (Id. at 696-700.) She testified that in the Final Mayo EIS, those comments were indeed addressed:

> And one of the key aspects about the final statement is that it said the final EIS had looked at all of the issues that had been raised with regard to groundwater and the ability of groundwater potentially to impact Crutchfield Branch. And the solution to that, which was laid out in the final EIS, was that it would be addressed through the NPDES permit …. And, in fact, that's what happened.

(Id. at 696.)

Thus, the Corps, in accordance with the NEPA process, received comments from, among others, EPA Region IV. It also received input and comment from other agencies, including DEQ. The DEQ comments were repeated by the Corps in Section 2.2.2 of the Mayo EIS, in which the Corps addressed groundwater concerns related to the Mayo project. The DEQ comments indicated, first, that the Company would be required to complete groundwater studies related to the potential for environmental impact. (Mayo EIS, at 2-6.) The Company did so – it commissioned the Floyd Report, which concluded that "it is difficult to imagine that any significant adverse impact on the ground water aquifer could be caused by ponding of the ash wastes at the proposed site." (Floyd Report, at 15.) The DEQ comments further indicated, as witness Williams testified, that all discharges to Crutchfield Branch would be covered by the NPDES permit for the ash pond, and that the permit also provide for testing to ensure no impact upon Crutchfield Branch. This, too, was done. The NPDES permit was issued (Tr. vol. 19, 698-99) and surface monitoring of Crutchfield Branch was written into the original NPDES permit in 1982 and each subsequent permit in order to confirm that any groundwater impacts were not being realized in that surface water stream. (Id. at 674-75, 699.)

The DEQ comments concluded by indicating DEQ believed "that by including this language in the NPDES permit for the Mayo project sufficient controls will be available to assure that examination of potential groundwater pollution is completed and that appropriate remedial action is taken by the Company prior to the completion of the project." (Mayo EIS, at 2-6.) Witness Williams, testifying from the EPA perspective, concurred. She expressly disagreed with Sierra Club's characterization of EPA Region IV's comments:

But secondly, and I think really importantly, the EPA Office of Solid Waste[45] continued to look at this whole issue of whether or not unlined ponds were protective throughout the 1980s, as I had mentioned earlier today, and also looked at the question of groundwater monitoring, and continued to find both unlined ash ponds and the need for groundwater monitoring to be site specific, and … found them to be the industry standard and not unreasonable with respect to impacts on groundwater through the 1980s. And you can even take it beyond that, because EPA did not really make its determination [regarding unlined ash ponds] until it finalized the CCR Rule in 2015.

(Tr. vol. 19, 700.) Thus, rigorous – as opposed to surface – analysis of the Mayo EIS would reveal that, first, the final conclusion of the entire study was that the ash ponds at Mayo would not have a significant environmental impact, and, second, that the manner in which the agencies charged with protecting the environment would assure this outcome would be through the NPDES permitting process. The Sierra Club's attack on the Company using a couple of lines from a single set of comments does not comport with rigorous analysis.

Intervenors' inability or unwillingness to avoid hindsight analysis makes their testimony unreliable and untrustworthy. The Commission does not credit this testimony, and disregards it when assessing the Company's conduct under the prudence framework. Further, while intervenors may, in their roles as partisan advocates, avoid rigorous analysis of historical documents, the Commission is not a partisan advocate – on the contrary, it is a neutral administrative body charged by the Legislature with setting rates that are just and reasonable, fair to both the utility and its customers. It cannot fulfill that mandate without rigorous analysis of the historical documents introduced by the parties, and without the avoidance of partisan advocacy.

Discussion of Question #3: The Company's Entitlement to a Return

DEP seeks a return, at its weighted average cost of capital (WACC),[46] on deferred CCR Costs during two distinct periods: the Deferral Period and the Amortization Period, both defined herein. The Deferral Period is the period from the time the costs were first incurred through the date upon which they begin to be brought into rates; for purposes of this case the return applies to the period through August 31, 2020. As it did in the Company's prior rate case, the Public Staff supports a WACC return in this period. (Tr. vol. 15, 1555.) The Commission approved such a return in the Company's last rate case, in DEC's last rate case (Docket No. E-7, Sub 1146), and in Dominion's last rate case (Docket No. E-22, Sub 562). Thus, the Commission will not further address a return on

[45] Importantly, not the regional office, but instead the EPA Headquarters office of which witness Williams became Director and which produced the 1988 EPA Report to Congress (Joint Ex. 13).

[46] Company witness Riley indicated that in the case of CCR-type costs, the "default" rate of return is the weighted average cost of capital (Tr. vol. 13, 406), which of course is necessarily true in order to compensate both debt and equity investors for the use of their capital.

CCR Costs during the Deferral Period herein; suffice it say that the reasons that a return is required during the Amortization Period apply equally to the Deferral Period.

The Amortization Period is the period over which deferred CCR Costs are amortized – that is, paid by customers over time – as they are brought into rates.[47] By definition, the CCR Costs to be recovered by the Company during the Amortization Period are prudently incurred – had they not been prudently incurred, the Commission would simply disallow them, and the issue of a return "on" such disallowed costs would not even be relevant.

The unamortized balance thus represents a loan by the Company to its customers. Under the spend/defer/recover model, prudently incurred CCR Costs were advanced by the Company to its customers, and are being paid back over time by its customers. Loans bear interest – the interest is the financing cost, the cost of the money borrowed. The return sought by DEC during the Amortization Period is synonymous with and equivalent to the cost of financing the unamortized balance of CCR Costs – the return is the cost of money. Responding to a Commission question, DEC witness Jane McManeus put it this way:

> [W]e use a number of terms when we're talking about this interest or return. Sometimes we call it the cost of money, sometimes we call it weighted average cost of capital, [sometimes] we say it's a debt and equity return, [but] it's [all] financing costs.

(Tr. vol. 13, 314.)[48]

Were the Commission to deny DEP a return on the unamortized balance of CCR Costs during the Amortization Period, it would convert the loan made by the Company to its customers from an interest-bearing loan to an interest-free loan. Forcing the Company to make an interest-free loan to its customers under the circumstances of this case would be contrary to law. The Commission granted DEP a return upon the unamortized balance in the 2018 DEP Rate Order (*See* 2018 DEP Rate Order, at 188), and recognized specifically in the DEC's last rate case that to deny DEC a return upon the unamortized balance would be unlawful. (2018 DEC Rate Order, at 290 (denying the return would impair the Company's ability to earn its authorized return and "[r]ates that impair the Company's ability to earn its authorized return are not just and reasonable … and the Commission would act contrary to law were it to order them.").) The facts and circumstances which led the Commission to that conclusion in DEC's last case apply

[47] The approved Amortization Period in the Company's last rate case was five years, and the Company proposes a like period in the current case. While it disagrees with the five-year period proposed, it agrees that amortization over some multi-year period is appropriate. (Tr. vol. 15, 1552-53.)

[48] On September 25, 2020, the Company and the AG filed a Joint Stipulation (Joint Stipulation) in which the stipulating parties agreed that, subject to the Commission's approval, the testimony of witness McManeus in the DEC-specific hearings could be entered into the record in this case as if given by DEP witness Smith. Witness Smith affirmed that she agreed with the stipulated testimony, and had no objection to the answers given by witness McManeus. (Tr. vol. 13, 283-84.)

equally to this case, and the conclusion still holds. What is different today are the expectations created by that decision as well as the Commission's decision in the Company's own prior case. These expectations lead to another reason for the Commission to award a return.

In the last round of rate cases for DEC and DEP, the Commission was writing on a blank slate. Coal ash cost recovery had not as yet been dealt with by the Commission in a fully litigated case. Both the prior DEC case and the prior DEP case were, however, fully litigated. In DEP's case, with the exception of $9.5 million excess disposal costs incurred at the Asheville Plant, the Commission allowed almost full recovery of coal ash costs at issue, based on its finding that those costs had been prudently incurred.[49] It further awarded full recovery (less a cost of service penalty) of a return on the unamortized balance of those costs as they were brought into rates during the Amortization Period. But the Commission went further. Rejecting an alternative cost recovery model (the "run rate") proposed by DEP, it held that instead DEP would be required to keep to its spend/defer/recover model of cost recovery, and that in the Company's next general rate case (which of course is this case) the Commission would undertake its prudence review of coal ash costs and "unless future imprudence is established, … [the Commission would] permit earning a full return on the unamortized balance." (2018 DEP Rate Order, at 206.)

The "spend" in spend/defer/recover represents funds advanced by the Company's investors. No investor advances funds without an expectation of a return. The promise embedded in the Commission's decision to require continued adherence by the Company to spend/defer/recover highlights even more that a Commission decision to deny the return in this case would be unlawful. Denial of an investment backed expectation is the foundation of a constitutional "takings" claim. (*Penn Cent. Transp. Co. v. New York City*, 438 U.S. 104 (1978).)

Simple fairness also must be factored into the equation. As witness McManeus testified, "[W]hen I think of what the Company's requesting, I think of it in terms of being made whole, and being made whole in terms of cost." (Tr. vol. 13, 315.) DEP cannot by definition be "made whole" if a significant cost (the cost of money) is disallowed in the same decision in which the underlying costs being financed are found to have been prudently incurred, and, therefore, are recovered – but recovered, as a rate mitigation measure to help customers, over time. Money is not free; to the contrary, it has a cost (Tr. vol. 13, 200, 207, 281-82), which no one disputes

But fairness is not simply a matter of equity; it too is a legal requirement. Under N.C.G.S. § 62-133(a) rates set by the Commission must be fair to both the Company and its customers. Forcing the Company to make an interest-free loan to its customers can

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[49] The Company's cost recovery request was approximately $242 million; the Commission disallowed $9.5 million. (2018 DEP Rate Case Order, at 18.)

hardly be said to be "fair" to the Company. That is what also makes it illegal under N.C.G.S. § 62-133(a) and confiscatory under *Bluefield*/*Hope*.[50]

In DEP's last rate case the Commission noted that the Company and the Public Staff had engaged in a dispute over whether a return "must" or merely "may" be allowed, with the Company advocating "must" and the Public Staff advocating "may." (*See* Order on Motion for Clarification, Docket No. E-2, Sub 1142 (April 17, 2018) (Clarification Order), at 3-4.) The Commission determined that it was unnecessary to decide this issue (Id.)

This same debate played out in DEC's last case, and included a further controversy between the Company and the Public Staff on the appropriateness and effect of the ARO accounting employed by both DEC and DEP in their prior cases, and both DEC and DEP in their current cases. DEC's testimony and argument in its prior case showed that it appropriately accounted for CCR Costs in AROs, and that pursuant to the ARO accounting rules those costs were capitalized and therefore should bear a return. The Public Staff took the position that the costs, even if accounted for in AROs, were deferred expense, and, therefore, a return was not required. Here, while indicating that the Company's position was correct and supported a return, and that the Public Staff's position was "not persuasive, not supported by authority and not determinative … [and] also incorrect as a matter of accounting," the Commission again determined that this was an issue unnecessary to resolve. (2018 DEC Rate Order, at 289.)

In the interest of not encouraging further re-litigation of these issues, the Commission resolves them here. The Company is legally entitled to a return, at its weighted average cost of capital during the Deferral Period, and is also legally entitled to a return, at its weighted average cost of capital, upon the unamortized balance of coal ash costs as those costs are brought into rates during the Amortization Period. Those costs – the "spend" in spend/defer/recover – are "property used and useful" in the service of customers. Refusing to award the financing costs results automatically and as a matter of mathematics in impairment of the Company's earnings, which not only is prohibited by *Bluefield*/*Hope*, but in turn results in rates that are "unfair" to the Company in violation of N.C.G.S. § 62-133(a) and in violation of the Commission's mandate to set rates that are just and reasonable. Were it to refuse a return, the Commission would, in its own words, be acting "contrary to law." (2018 DEC Rate Order, at 290.)

A. Property Used and Useful

Under the Public Utilities Act, the Commission must provide the utility with the opportunity, by sound management, to (1) produce a fair profit for its shareholders, in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital. *State ex rel. Utils. Comm'n v. Gen. Tel. Co. of the*

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[50] The interest-free nature of the loan means that the Company's ability to earn its authorized return would necessarily be impaired, and impairment of its ability to earn its authorized return constitutes an unconstitutional taking of property. *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) (*Hope*); *Bluefield Waterworks & Improvement Co., v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923) (*Bluefield*).

Southeast, 281 N.C. 318, 370 (1972). As the Supreme Court held in that case, these factors constitute "the test of a fair rate of return declared" in *Bluefield* and *Hope*. (Id.) These requirements are built into the rate-making statute, N.C.G.S. § 62-133. The rate of return deemed sufficient by the Commission to accomplish these ends is set in accordance with Section 62-133(b)(4), and the property to which the return is to be applied is measured in accordance with Section 62-133(b)(1), which states that the return is to be on "property used and useful, or to be used and useful within a reasonable time after the test period, in providing the service rendered to the public within the State."

The statute does not define the phrase "property used and useful." Intervenors appear to have a narrow view of its meaning, asserting that "used and useful" property is confined to utility plant assets that generate, transmit, and distribute electricity. The Commission has already decided that this narrow interpretation is incorrect (2018 DEP Rate Order, at 193-96), and, indeed, DEP provides examples of non-utility plant assets that are nonetheless classified as property used and useful, such as reserve fuel and cash working capital. (Tr. vol. 13, 201.)

In *State ex rel. Utils. Comm'n v. Virginia Elec. & Power Co. (VEPCO)*, 285 N.C. 398, 414-15 (1974), the Supreme Court expressly recognized that when a utility keeps on hand a reasonable amount of shareholders' funds (in the form of cash) to pay operating expenses, such working capital constitutes property that is used and useful in providing retail electric service and should be included in rate base. The Court held:

> 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.

(Id.) Thus, to the extent that intervenors continue to assert that "property used and useful" is limited to a utility's physical plant, that position is contrary to North Carolina law. Instead, under *VEPCO*, what stands as "property used and useful" does not turn on whether the property generates electricity, but whether it serves the public and was paid by debt or equity investors – rather than through rates that were set in anticipation of normal operating expenses.[51]

The CCR Costs DEP seeks to recover in this case were incurred as a result of the changes in law wrought by the CCR Rule (promulgated in 2015) and CAMA (initially enacted in 2014 and amended in 2016). On December 21, 2015, DEC and DEP submitted

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[51] In DEC's 2018 Rate Order, the Commission noted that it appeared that the Public Staff "misunderstood" the Company's position on what constitutes "property used and useful." (2018 DEC Rate Order, at 290.) In this case as in DEC's and DEP's last rate cases, the Public Staff again misapprehends the Company's reliance upon *VEPCO* and its reference to working capital being "property used and useful." (Tr. vol. 15, 1575-78.)

to the Commission and the Public Staff a letter (Savoy Letter, DEC Junis/Maness Cross Examination Ex. 4)[52] that outlined the spend/defer/recover model DEC and DEP would follow in connection with their incurrence of the costs and the recovery of those costs in rates. The Commission in the 2018 DEC Rate Order noted that "through the Savoy Letter the Company [indeed, both DEC and DEP, as the Savoy Letter was from both of them] told the Commission and the Public Staff, and the Commission told all interested parties" exactly how the program would work. (2018 DEC Rate Order, at 289.) No party objected to the Company's plan; indeed the Public Staff agrees that spend/defer/recover is the program in which the Company has been engaged, and that the program was outlined in the Savoy Letter and the subsequent formal deferral request submitted by DEC and DEP. (Tr. vol. 15, 1689-1690.)

To put CCR Costs into *VEPCO* terms, the "spend" in spend/defer/recover is "property" akin to the working capital that the Court held was properly counted as rate base, upon which a return was statutorily required. It is cash supplied by investors, just like working capital is cash supplied by investors.

It is completely undisputed that the spent and deferred CCR Costs which DEP seeks recovery of in this case were advanced by the Company's investors, and are not included in current rates. DEP witness Smith so stated in her rebuttal testimony (Tr. vol. 13, 200), and DEC witness McManeus reiterated it in response to a question from the Commission:

> [T]he way I think about it is, when we have amounts that we spend, for example, on coal ash, that are not yet reflected in our rates -- so, for example, the 2018, '19 spend is not reflected in our rates … by definition, investors [both debt and equity] are advancing these funds.
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> …So when we say we want a return, we're talking about total financing costs on these amounts that have been advanced, and it's made up of both debt and equity.

(Tr. vol. 13, 314-315 (emphasis added).) No party submitted contradictory evidence, and Public Staff witness Michael Maness actually agreed. (See Tr. vol. 15, 1578 ("The utility has already spent the money represented by the deferred costs in question; therefore, it will be required to borrow the money or use equity to finance the spent costs until it can recover them from ratepayers.").)

The "spend" in spend/defer/recover not only is "property" within the meaning of *VEPCO* and Section 62-133(b)(1), it is also provided in service to customers – the "spend" was made, and is continuing to be made, in order to comply with changes in the law; indeed, the Company does not have the option to *not* comply with changes in the law. (*See* 2018 DEC Rate Order, at 268-69 ("Capital expenditures undertaken to enable

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[52] This exhibit is through the Amended Stipulation now a part of the record in this case. (Tr. vol. 15, 1817.)

compliance with the law qualify as 'used and useful,' in that the Company does not have the option to fail to comply …").) Here, too, intervenors have a narrow view of the meaning of the words of the statute. Witness Maness indicates that CCR Costs (which is what the "spend" constitutes) relate "to service that was provided in the past," and which are "not really providing any additional benefits to customers in terms of additional electric service or improvements of service." (Tr. vol. 15, 1778-79.) But this is incorrect – the spend is occurring today as a result of changes in the law that came into being in 2014, 2015, and 2016.[53] But for the changes in law, there is no evidence whatsoever that the "spend" would be occurring at all. CAMA and the CCR Rule mandate basin closure – until they came into being, continued operation of the Company's ash ponds was entirely legal, and premature retirement could well have been imprudent and more expensive than the costs being incurred today. CAMA and the CCR Rule require the specific steps that the Company is taking to address and remediate groundwater contamination resulting from the normal operation of the basins. But for their prescriptive requirements, there is no evidence whatsoever that assessment and remediation of groundwater now being required would ever have been required under the law as it existed prior to CAMA and the CCR Rule.

In this case, Company witness Doss testified that the CCR Costs representing the "spend" funded by investors:

> [A]re 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. The achievement of those three purposes is used and useful as the utility has the obligation to comply with CAMA and the CCR Rule.

(Tr. vol. 16, 344.) Witness Doss provided identical testimony in DEC's prior case. (DEC 2018 Rate Order, at 257.) In DEC's prior case, the Commission credited his testimony, rejected the contrary testimony of witness Maness, who classified[54] the costs as "deferred

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[53] In DEP's last case, the Commission rejected the Public Staff's "label-driven classification" of "used and useful" (2018 DEP Rate Order, at 195-96), noting as a "concrete example" that the "spend" in that case included new landfills with new liners, capital items with service lives of in excess of one year. (Id.) In DEP's current case, for example, its "spend" on a system basis through June 30, 2019 in connection with construction of the Cape Fear and H.F. Lee beneficiation facilities – a requirement of the 2016 CAMA amendments – was in excess of $106 million. (Tr. vol. 12, 51.) These facilities are essentially manufacturing plants designed to convert coal ash from the ash basins into a useable product in order to fulfill the reuse goals of CAMA as amended. The same considerations that drove the Commission in the 2018 DEP Rate Order to reject the Public Staff's "label-driven classification" apply with equal force in this case. Indeed, in light of examples such as the beneficiation projects, witness Maness' general classification of CCR Costs as "deferred expenses" is no less label-driven, and, as it did in DEC's last case, the Commission rejects it.

[54] In truth ***mis***-classified, as the Commission found as a fact that his position was "not persuasive, not supported by authority and not determinative … [and] also incorrect as a matter of accounting." (Id. at 289.)

expense" and therefore ineligible to even be counted as "used and useful," and found that the CCR costs that were the subject of the prior case were indeed "used and useful." (Id. at 292.) As the Commission held, quoting witness Doss, the achievement of CAMA/CCR Rule compliance and the other purposes of CCR spend "is used and useful as the utility has the obligation to comply with CAMA and the CCR Rule." (Id.)

Nothing has changed – the Company and the Public Staff extensively debated the appropriateness and effect of ARO accounting in the previous rate cases, and the same evidence was again submitted in this case, from witness Maness for the Public Staff, and witness Doss for DEP. The only "new" evidence came from Company witness Riley, but it served merely to buttress from a national perspective what witness Doss testified to from a Company-specific perspective.

In the prior DEC Rate Case, and after extensive discussion of applicable accounting standards under GAAP and FERC standards, along with the Commission's own deferral standards, the Commission ruled:

> While the accounting rules detailed herein are complex, in simplified terms, both GAAP and FERC accounting guidance require the recognition of a liability (the ARO) upon the requisite triggering event – the legal obligation to retire the Company's coal ash basins. Recognition of the liability carries with it recognition of a corresponding asset – ***the capitalized cost of settling the liability, which under both GAAP and FERC rules is considered part of the property, plant and equipment for the assets that must be retired***.[55] While under ordinary circumstances these recognition events would be reflected over time in the Company's income statements, because of the deferral order in Docket No. E-7, Sub 723, the income statement impacts are deferred into regulatory assets "pending further orders of the Commission." The Company in this case is seeking such a further order, so as to reflect in rates the outflow of cash that it has incurred – and that its investors have funded – as it proceeds to settle the asset retirement obligation created by the CCR Rule and CAMA.

(2018 DEC Rate Order, at 288 (emphasis added).) This is what witness Doss testified to in DEC's prior case, and what witnesses Doss and Riley testified to all over again in this case. (Doss: Tr. vol. 16, 409 (when Company records an asset retirement obligation the corresponding asset retirement costs are capitalized and are integral to the plant that gave rise to the costs, and this is clear in GAAP and FERC guidance); Tr. vol. 17, 43 (costs are capitalized as part of the property, plant and equipment that gave rise to the retirement obligation); Riley: Tr. vol. 13, 407-08 (FASB does not look at asset retirement cost as being a separate intangible asset; rather it "is part of the coal facility itself … part of that operating long-lived asset"); Tr. vol. 17, 44 (retirement "costs are considered

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[55] This corresponding asset is the "Asset Retirement Cost," and is part of the long-lived asset (in the Company's case, the coal plants associated with the coal ash basins) whose required closure as a result of changed legal obligations created the liability – the ARO. (Tr. vol. 13, 392.)

integral to the operation of the asset, in this case the coal plants, and therefore should be capitalized"); id.. at 69 (from Riley's national perspective, capitalization of costs is consistent with how they are considered "across the country nationally by utilities").)

Capitalized costs bear a return. The CCR costs incurred by DEP are capitalized costs, funded by the Company's investors, who advanced the funds expecting a return. In the 2018 DEC Rate Case, the Commission held that the deferred funds used to pay for the CCR costs at issue in that case:

> [W]ere furnished by the Company and its investors, and the costs are eligible for a return on, not merely a return of, those funds, lest its earnings be impaired. In this sense, just like "classic" working capital, these funds are "property" of the Company, used and useful in the provision of electric service to its customers. Such funds, properly accounted for in an ARO, are eligible [for] "deferral and amortization and for earning on the unamortized balance."

(2018 DEC Rate Order, at 292.) The Commission came to the same conclusion in the Company's prior case, although again couching its observation in the context of its discretion: "Costs placed in an ARO account are eligible for deferral and amortization and earning on the unamortized balance. As such, even if the remediation costs are ARO expenditures, they are eligible for ratemaking treatment as though they are used and useful assets." (2018 DEP Rate Order, at 196.) The CCR Costs involved in this case are exactly the same. Nothing has changed, and the *VEPCO* decision and the Public Utilities Act mandate a return.

B. Deferral and Amortization Support a Return "On" Prudently Incurred Costs

In the prior DEP/DEC rate cases, the Commission awarded a return on the unamortized balance of coal ash costs in light of specific circumstances tied to the spend/defer/recover model. The Commission first noted that coal ash costs had been advanced by investors – that is, the "spend" in spend/defer/recover was investor-supplied capital, and was not already included in customer rates. (2018 DEC Rate Order, at 290-92; *see also* 2018 DEP Rate Order, at 195.) The Commission held that the costs had been deferred by order of the Commission – that is, the "defer" in spend/defer/recover was Commission-sanctioned under the well-defined and long established rules governing deferral, in that CCR Costs were extraordinary in type and magnitude such that failure to defer would have a significant impact on the Company's earned returns. (2018 DEC Rate Order, at 206-07, 292-93; *see also* 2018 DEP Rate Order, at 138-41.) And, finally, the Commission noted that not awarding a return would impair the "recover" part of spend/defer/recover, because unless the investors who advanced the capital so as to permit the Company to "spend" received a return on the unamortized balance during the Amortization Period, the Company's ability to earn its authorized return would be impaired. (2018 DEC Rate Order, at 290.) That, of course, would mean that the investors would not be fully compensated for the use of their capital.

In the prior DEC case the Commission specifically concluded "The funds used to pay for these costs were furnished by the Company and its investors and the costs are eligible for a return on, not merely a return of, those funds, lest its earnings be impaired." (Id. at 292.) While the Commission couched this conclusion in the language of "discretion," in reality the same factors it relied upon to award a return in the exercise of its discretion add up to the Company's legal entitlement to a return. That is because impairment of the Company's ability to earn its authorized return is, as the Commission already concluded in the 2018 DEC Rate Order, illegal. The reason for this is the deferral structure embedded in spend/defer/recover and approved by the Commission in the 2018 DEP and DEC Orders.

In DEP's last rate case, the Commission approved the deferral of CCR Costs currently being sought for recovery. (2018 DEP Rate Order, at 141.)[56] While that Order is currently on appeal, the deferral was not appealed. No party to the appeal argues in the appeal that deferral of ongoing coal ash costs is improper. Deferral has consequences, as the Commission has previously held:

> The point of a deferral is that the costs to be deferred are of a magnitude that they need to be taken out of the normal ratemaking accounting process and set to one side for later inclusion in rates, lest the Company lose its ability to recover them. Tr. Vol. 9, pp. 123-24. Should the Company's ability to recover such costs be impaired, it will not be able to earn at its authorized rate of return. *Id*. at 124. Setting them to one side means that unless a return is allowed, the Company's ability to earn its authorized rate of return is again impaired. Further, ***if in the process of bringing the deferred costs into rates the costs are amortized over a period of years, not allowing a return on the unamortized costs again impairs the Company's ability to earn at its authorized rate of return. Rates that impair the Company's ability to earn its authorized return are not just and reasonable … and the Commission would act contrary to law were it to order them.***

(2018 DEC Rate Order, at 290 (emphasis added).)

In this case the Commission has set an authorized rate of return (ROR) pursuant to N.C.G.S. § 62-133(b)(4). As witness Maness indicates, setting the authorized ROR in a rate case means that the Commission is "supposed to give … [the Company] the opportunity to recover just that cost of capital" coming out of the case. (Tr. vol. 7, 36.) But if it in that same rate case the Commission disallows a future cost – the cost of money as

[56] The Company has also requested authorization to continue deferral of its coal ash environmental compliance costs beginning March 1, 2020, as well as the depreciation and return on CCR compliances investments related to continued plant operations placed in service after February 29, 2020, along with a return on both the deferred balances at the overall rate of return approved in this case, for cost recovery consideration in a future rate case. Deferral is appropriate for the same reason that the Commission granted the Company permission to defer similar costs in the 2018 DEP Rate Order, and granted deferral to DEC in the 2018 DEC Rate Order.

CCR Costs are brought into rates in the future, during the Amortization Period – the Commission would automatically and mathematically make it impossible for the Company to earn the ROR it had just authorized.

Company witness Riley put the concept in more concrete terms. He noted first that if the Company is actually in an "out-of-pocket cash" situation[57] and it receives less than a full return then "that would be viewed as being a disallowance" (Tr. vol. 13, 405-06) – an "implicit" disallowance (DEC Tr. vol. 24, 37), but a disallowance nonetheless. Commissioner Hughes posed a hypothetical in which "$500 million was sought … and $500 million was granted, but over a period of time that caused a net present value disallowance." (Id. at 422). Witness Riley's response captures the impairment caused by the loss of the return in terms of the accounting for the loss, but it also illustrates the impairment of earnings implicit in the disallowance:

> [I]n your example, if the Company's seeking $500 million in recovery and they're granted $500 million in recovery, except if the Company is out-of-pocket cash today $500 million and they're not going to recover that for, say, a period of time, call it 25 years, they have used shareholder monies today, and shareholders expect a return on the use of their funds.
>
> So to the extent that the Commission were to only grant recovery over a 25-year period … in present value dollars it's something less than $500 million.
>
> And what the accounting would require is for the Company to assume or to assess what return would it have expected to get on those dollars, and I would have expected weighted average cost of capital. They would present value of those dollars back to today's dollars to today. Using your example, say that discounts back to $400 million. They would take a charge of $100 million for that implied disallowance in accordance with the accounting standard.
>
> So, in effect, because they're not getting a return on their money, that has to be recognized today as a charge.

(Id. at 422-23.) That same $100 million charge, or implicit disallowance, is – mathematically – an impairment upon the Company's ability to earn its authorized ROR. Amortizing the costs pre-funded by investors means that investors have in effect lent the money funding the costs to customers. Denying the financing costs attendant upon the loan being repaid over time impairs the Company's ability to earn its authorized ROR – an ROR authorized by the Commission in this very Order.

Deferred costs are costs pre-paid by the Company and its investors. (Lesser & Giacchino, at 52.) Amortizing them as they come into rates means that investors are lending the money funding the costs to customers. Denying the financing costs attendant

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[57] The Company ***is***, of course, out-of-pocket cash in the spend/defer/recover scenario.

upon the loan being repaid over time impairs the Company's ability to earn its authorized ROR – an ROR authorized by the Commission in the very same Order that disallows the financing cost.

Impairing the Company's ability to earn its authorized ROR is illegal under *Bluefield*/*Hope*, the requirements of which are built into the rate-making statute through N.C.G.S. §§ 62-133(b)(1) and 62-133(b)(4). It is also illegal under N.C.G.S. §§ 62-133(a), which requires the Commission to set rates that are just and reasonable, and fair to the utility and its customers. A rate order that requires the Company to make a forced interest-free loan to its customers is not "fair" to DEP and its investors.

Further, sound economic principles underpin the award of a return on the unamortized balance as deferred costs are brought into rates over time. Barring extraordinary circumstances, operating expenses are paid through electricity rates, which are set at a level to cover those operating expenses based upon a test year which, as adjusted, is designed to mimic the electric utility's ongoing costs. When extraordinary expenditures arise that justify deferral, they are paid not through electricity rates set in anticipation of those costs but by funds advanced by the utility's debt and equity investors. In order to fully recover these expenditures, the financing cost attendant upon the advancement of the funds needs to be recovered – this is the return "on" those expenditures. Accordingly, the Company is entitled to a return at its weighted average cost of capital to be set in this case upon the unamortized balance of CCR Costs as those costs are brought into rates during the Amortization Period.

These principles were echoed and reinforced in witness Riley's testimony. He stated that "Once there is a cash outlay by the Company, now there has been a use of investor funds, shareholder funds, it's appropriate to allow a return on the uncollected balances to reimburse shareholders for the use of those funds." (Tr. vol. 17, 69.) And the flipside is also true – if amounts are collected from customers in advance of the expenditures being made, then customers are reimbursed for the use of their funds through a reduction in rate base. (Id. at 69-70.) The Commission recognizes this with respect to excess deferred income taxes (EDIT), where "customers prepaid for a cost which will now not materialize." (Tr. vol. 13, 208.) It has ordered that until EDIT is flowed back to customers or otherwise dealt with, the prepaid amounts bear "interest reflected at the overall weighted cost of capital approved in … [the] Company's last general rate case proceeding." (Id.) EDIT reflects, in effect, a loan from customers to the Company, and the Company will repay the loan, with interest. Likewise, when prudently incurred CCR Costs are brought into rates over time during the Amortization Period, those costs represent a loan from the Company and its investors to customers – and that loan, too, should also bear interest.

The Company's investors, who advanced the funds that are the "spend" in spend/defer/recover, would not have done so had they not had an expectation that their funds so invested would bear a return, and that return is the cost of the money – money they invested that allowed the Company to "spend" and incur legally required CCR Costs. Accordingly, the Commission should award a return at the Company's weighted average cost of capital to be set in this case upon the unamortized balance of CCR Costs as those costs are brought into rates during the Amortization Period.

Indeed, the 2018 DEP Rate Order created an investor expectation that a return "on" the unamortized balance of deferred CCR Costs would be awarded in future rate cases – in particular, *this* rate case – so long as the Company met its obligation to prove that the costs for which it sought recovery were prudently incurred. The creation of this expectation is another reason why the return sought by DEP is warranted.

C. <u>The Expectations Generated by the Commission's Prior Order</u>

In DEP's prior case, the Commission allowed recovery of prudently incurred coal ash basin closure costs as well as a return on those costs, less a cost of service penalty. DEP had also sought recovery of then-future CCR Costs – which include of course costs *now* sought for recovery – through a "run rate" pursuant to which customers, not the Company's investors, would fund a significant portion of (if not the bulk of) ongoing CCR Costs. The Commission rejected the "run rate" concept, and held:

> ***Instead***, CCR remediation costs incurred by DEC during the period rates approved in this case will be in effect shall be booked to an ARO that shall accrue carrying costs at the approved overall cost of capital approved in this case (the net of tax rate of return, net of associated accumulated deferred income taxes). ***The Commission will address the appropriate amortization period in DEC's next general rate case, and, unless future imprudence is established, will permit earning a full return on the unamortized balance.***

(2018 DEP Rate Order, at 206 (emphasis added).) Thus, the Commission did not merely *endorse* the spend/defer/recover model in which the Company was engaged, and had been engaged in since the laws regarding coal ash management changed with the passage of CAMA and the promulgation of the CCR Rule – the Commission *required* spend/defer/recover. (*See* Tr. vol. 4, 20 (Commission in not granting run rate forced Company to spend and defer the costs, but indicated that in so doing it would incorporate into rates the financing costs associated with that effort).) Further, the Commission's ruling "puts the focus of the Company's cost recovery request where it belongs – on the Commission's examination of the prudence and reasonableness of the costs for which the Company seeks recovery[.]" (Tr. vol. 13, 204.) That is, the ruling puts the focus on execution risk, which the Company and its investors properly assume, and not on the risk of an inappropriate disallowance of cost, which the Company and its investors do not and did not assume.

The Company's "next general rate case" is this case. DEP has done what the Commission asked. It booked its ongoing CCR expenditures – deferred by order of the Commission and funded entirely by investors – to an ARO. It has borne the burden of proving that its CCR expenditures were prudently incurred, so "future imprudence" as to the CCR Costs which it seeks to recover has *not* been established. A return during the Deferral Period is not opposed by the Public Staff. All that remains is for the Commission to uphold and fulfill the expectation that it created – the expectation that a return "on" CCR Costs would be awarded during the Amortization Period. Dashing investment backed expectation is a recipe for a "takings" claim. *See Penn Cent. Transp. Co. v. New York City*, 438 U.S. 104 (1978). It is also a recipe for the abrogation in North Carolina of the regulatory compact. The Commission is not interested in abrogating the regulatory compact in North Carolina.

The underlying predicate with respect to the costs to be brought into rates over time during the Amortization Period is that the costs were prudently incurred – because if they were not prudently incurred, the Commission would simply disallow them and there would be no question of a return "on" the disallowed costs. Investors accept the risk of prudence-based cost disallowance. That is "execution" risk – the Company must execute in order to recover its costs. But denying a return "on" prudently incurred costs goes well beyond execution risk. Rather, it strikes at the heart of the regulatory compact.

In the 2018 DEC Rate Order the Commission explained in detail the regulatory compact:

> A central operating principle underlying utility rate regulation in North Carolina (and virtually all other jurisdictions) is that the utility's costs are recoverable in rates. As two of the leading modern commentators on utility regulation put it …
>
>> No firm can operate as a charity and withstand the rigors of the marketplace. To survive, any firm must take in sufficient revenues from customers to pay its bills and provide its investors with a reasonable expectation of profit …. Regulated firms are no exception. They face the same constraints ….
>>
>> A basic concept underlying all forms of economic regulation is that a regulated firm must have the opportunity to recover its costs. … Without the opportunity to recover all of its costs and earn a reasonable return, no regulated private company can attract the capital necessary to operate.

(2018 DEC Rate Order, at 257 (quoting from Lesser & Giacchino, at 39).) Inducing investment carries a cost, too – the cost of money. Justice Brandeis, in his dissenting opinion in which he articulated the prudence principle, articulated as well that the capital cost, the cost of money, is a "cost" to the utility no less than "operating expenses, depreciation, and taxes." *Missouri ex rel. Sw. Bell Tel. Co. v. Pub. Serv. Comm'n,* 262 U.S. 276, 306 (1923) (Brandeis, J, concurring and dissenting). This Commission has emphatically and repeatedly reaffirmed this principle.[58]

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[58] *See, e.g.,* Order on Remand, Docket No. E-7, Sub 989 (Oct. 23, 2013), at 22; Order Granting General Rate Increase, Docket No. E-7, Sub 1026 (Sept. 24, 2013), at 23.

To refuse a return in the circumstances of this case is to disallow financing costs – in effect, as we have seen, to force the Company to provide an interest-free loan to its customers. This has consequences. As DEC witnesses Karl Newlin and Steven Fetter noted, investors vote with their wallets. (Tr. vol. 1, 57 (Newlin); DEC Tr. vol. 26, 135 (Fetter).) They have investment alternatives, and will go elsewhere if their return expectations are not met. Regarding recovery of CCR costs, and all other things being equal, investors "would prefer to go to a jurisdiction that would provide a return of and on as opposed to one … [that] provided just a return of, or even cut back the return of with no return." (DEC Tr. vol. 26, 138.) The evidence in this case shows that other jurisdictions, including Virginia, Georgia, Florida, and Indiana, provide for both recovery "of" and return "on" coal ash costs. (Tr. vol. 3, 56; Tr. vol. 4, 37; Tr. vol. 19, 64-65; DEC Tr. vol. 26, 79-80, 138.) Witness Riley answered "No" to Commissioner McKissick's question regarding whether other jurisdictions were "wrestling with" the coal ash issues (Tr. vol. 13, 410) – "No" because other jurisdictions were allowing "recovery of ***and on***" CCR costs, without disallowance. (Tr. vol. 13, 416 (emphasis added).)

The consequence of calling into question North Carolina's continued adherence to the regulatory compact is higher cost of capital, leading inexorably "to increased rates to North Carolina customers." (Tr. vol. 13, 417-18.) As witness Fetter noted, there are "another 180 utilities [investors] could invest in across the country outside North Carolina." (DEC Tr. vol. 26, 148.) The Commission is not interested in forcing an increase to the Company's cost of capital.

This is not a theoretical issue – the credit rating agencies have already signaled the negative consequences were the Commission to adopt in this case the "no return" treatment it adopted in the Dominion case. Moody's credit reports issued after the 2020 Dominion Rate Order was published contain the same warning – stable ratings outlook[59] is at risk if return on the deferred balance is disallowed. (*See* Tr. vol. 2, 51-55; Newlin Duke Redirect Ex. 3, at 3; Newlin Duke Redirect Ex. 4, at 4.) The Moody's report for the Company is Redirect Ex. 3 (DEP Report), and was published by Moody's on March 30, 2020. Noting that due to the ratemaking treatment the Company received from the Commission in its last case Moody's viewed coal ash costs as "akin to a capital expenditure" (id. at 4), the report warns "Our stable outlook assumes Duke Energy Progress will continue to be allowed to recover the majority of its coal ash remediation spending, ***and that it will be able to earn a return on the deferred balance***." (Id. at 3 (emphasis added).)

The non-theoretical nature of the threat was captured by DEP witness Steve Young, the Chief Financial Officer of Duke Energy Corporation. Noting that the Company's current credit ratings were "solid," he indicated that "where it's headed" was his worry, and central to that worry is the concern expressed by investors, "whether it's equity or debt … [are you] going to get recovery of your cost, including debt service, including the ability to pay a dividend." (Tr. vol. 3, 52.)

[59] "Stable outlook means that the rating agency doesn't intend … to take a ratings action on the Company." (Tr. vol. 2, 49.) A shift to negative outlook would be "a precursor to a downgrade." (Id.)

Witness Young's testimony establishes that it is the strength of the Company's credit ratings and balance sheet that allows the Company to ride out crises such as COVID-19 (Tr. vol. 3, 55), or shoulder the burdens of hurricane recovery (id. at 53), or successfully navigate the risks of operating nuclear power plants. (Id.) The strength of the balance sheet and DEP's current A-level rating allows it the flexibility to access short-term capital through the commercial paper market, and then go into the longer term debt markets at a time of its choosing, rather than be forced to pay what the market demands at a non-optimal time. (Id. at 54.) This flexibility is what allows the Company to keep capital costs low, but underpinning this flexibility is the "confidence of the lenders that we'll be able to recover all the cost" (id.), which of course includes financing cost. The flexibility goes away if investor confidence goes away – to the ultimate detriment of customers, who must bear the higher cost of capital in rates.

Investors follow and rely upon the Commission's rulings, decisions, and pronouncements. In the Company's prior Order, investors saw that the Commission decided to award DEP a return on the unamortized balance of deferred coal ash costs during the Amortization Period. Without any change in the underlying circumstances, investors will be hard pressed to understand a change in outcome, particularly when the Commission's own words promised no change in outcome.

The cost recovery concern expressed by investors and overhanging the Company's credit and equity profile is not an issue to be addressed by superficial arguments such as "the approval of credit ratings agencies is not a requirement on the Commission in setting rates" (Tr. vol. 3, 41), or that "nowhere in . . . [N.C.G.S. § 62-133] does it say that rates have to be set to avoid a downgrade . . . or increase the stock price of utilities" (DEC Tr. vol. 26, 107), or that Moody's or investors do not dictate the requirements of North Carolina law. These are strawman arguments. No one argues that Moody's or investors dictate the requirements of North Carolina law. Cost recovery in North Carolina is governed by the Public Utilities Act, decisions of the North Carolina appellate courts, and decisions of this Commission as it seeks to fulfill its legislative mandate to set just and reasonable rates, rates which must be "fair [both] to the … utility and to the consumer." N.C.G.S. § 62-133(a).

The Commission rejects these strawman arguments. The law does not prohibit the return; to the contrary a return is required, not because Moody's or investors seek to dictate this result, but because the Constitution and North Carolina law demand this result.

There is no provision of the Public Utilities Act, no decision of the North Carolina appellate courts, and no decision of this Commission that compels the Commission to force investors to bear the financing cost of prudently incurred CCR expenditures as those expenditures are brought into rates over the Amortization Period. This is particularly true when the costs are being amortized as a rate mitigation measure. There would be no financing cost whatsoever were 100% of prudently incurred CCR Costs included in rates on Day 1. Customers get the benefit of being able to spread the introduction of CCR Costs into rates over time – but the corresponding burden is that they should also shoulder the cost of money that is attendant upon recovery of CCR costs being spread out over time.

The role of the Commission itself in the legal framework of cost recovery cannot be underestimated. The key to the spend/defer/recover framework is the deferral – but for the deferral, there would be no issue today of CCR cost recovery, or a return on such recovery, because without the deferral the costs would already have been written off and expensed. (DEC Tr. vol. 23, 59-60.) Deferral, a construct of the Commission itself, is an integral part of the regulatory model that allows for the recovery of ARO costs for a regulated utility. (Tr. vol. 17, 68-70.) It is as much a part of North Carolina's legal landscape as the prudence framework or the concept of "used and useful" costs in rate base.

This brings us full circle to the deferral – which no party challenges – and the consequences thereof. As stated above, in DEC's prior case the Commission held:

> [I]f in the process of bringing the deferred costs into rates the costs are amortized over a period of years, not allowing a return on the unamortized costs again impairs the Company's ability to earn at its authorized rate of return. Rates that impair the Company's ability to earn its authorized return are not just and reasonable … and the Commission would act contrary to law were it to order them.

(2018 DEC Rate Order, at 290.)

Nothing has changed since the Commission wrote those words in 2018. Those words provide the rationale for recovery by DEP of a return "on" prudently incurred CCR Costs as those costs are brought into rates over time during the Amortization Period. Impairing the Company's ability to be "made whole" (Tr. vol. 13, 315) by disallowing its financing cost during the Amortization Period would be unconstitutional under *Bluefield*/*Hope*, and will lead to rates that are unjust, unreasonable, and unfair to the Company, while the Commission's mandate is to set rates that are just, reasonable, and fair to the Company.

Under the circumstances of this case, and in order to be made whole, DEP is entitled to a return at its weighted average cost of capital on the unamortized balance of CCR Costs as those costs are brought into rates during the Amortization Period.

D. Additional Public Staff Arguments Against a Return

The principal reason the Public Staff removes CCR Costs from rate base so as to deny the Company a return on the unamortized balance of those costs during the Amortization Period is to implement its 50/50 "equitable sharing" theory, a theory that is standard-less and arbitrary. But protection of its chosen sharing percentage is not the only reason that the Public Staff would deny a return on the unamortized balance. It also makes a legal argument based upon its classification of CCR Costs as "deferred expenses," noting that expenses are not "property used and useful under 62-133(b)." (Tr. vol. 15, 1779.) But that classification of CCR Costs as "deferred expense" was upon a fully litigated record rejected by the Commission in DEC's prior rate case as "not persuasive, not supported by authority and not determinative … [and] also incorrect as a matter of accounting." (2018 DEC Rate Order, at 289.)

The Public Staff also relies on two additional factors to induce the Commission to exercise what the Public Staff contends is the Commission's discretion to deny a return: (1) intergenerational equity and the matching principle,[60] and (2) an asserted "history" of sharing of extremely large costs, exemplified according to the Public Staff by cases involving the cost of environmental cleanup of manufactured gas plants and the cost of abandoned nuclear generation facilities. Even assuming that the Commission has the discretion to deny a return, neither of these factors is persuasive.

1. Intergenerational Equity and the Matching Principle

The Public Staff asserts that intergenerational equity considerations apply (Tr. vol. 15, 1779), which is a follow on to its argument that CCR Costs are not "used and useful" because they relate to service to customers in the past, with no benefit to present and future customers. But intergenerational equity considerations are inappropriate in the context of the Company's coal ash basin closure costs, all of which have been incurred since December 31, 2014 as a result of changes in the law and for purpose of complying with legal requirements that did not even exist prior to the passage of CAMA in 2014. The costs recovered in the Company's prior case related to the period from January 1, 2015 through August 31, 2017; the costs in this case relate to the period from September 1, 2017 through February 29, 2020. No customer in "past decades," to use witness Maness' term (Tr. vol. 15, 1779), would ever have had to pay CCR Costs, because those particular costs did not even exist, and would not have existed, prior to the time the legal requirements for management of coal ash changed in 2014.

Properly understood, intergenerational equity concerns are completely different, and were explained by the Supreme Court in *State ex rel. Utils. Comm'n v. Edmisten*, 291 N.C. 451 (1977). This case involved a gap in the General Assembly's enactment of a fuel adjustment clause. The gap rendered fuel costs incurred by the utilities operating in North Carolina for several months immediately prior to the enactment's effective date uncollectible without relief from the Commission – specifically, a surcharge upon rates to billed in the months following the statute's effective date. The Commission granted permission for the surcharge, but the Supreme Court reversed. Noting (291 N.C. at 469) that prospective ratemaking, either to recover unexpected past expense or to refund expected past expense that did not materialize, was not authorized by the Public Utilities Act, the Court held

> Such rate making throws the burden of such past expense upon different customers who use the service for different purposes than did the customers for whose service the expense was incurred. For example, the surcharge here in question requires Duke's customers in the winter months to pay more than

[60] The AG makes a similar argument. (*See* Tr. vol. 13, 896.)

> they otherwise should pay for their service because of the cost of coal burned in July and August in supplying electricity for air conditioning.

(Id. at 470.) Here, by contrast, there is simply no "past expense" to burden present or future customers – CCR Costs in this rate case, which were deferred by express order of the Commission, are currently deferred costs, not yet in rates, being sought for recovery from current and, during the Amortization Period, future customers of the Company. The financing costs will be recovered from customers of the Company contemporaneously with the incurrence of those costs.

2. The Manufactured Gas Plant and Nuclear Abandonment Cases

Citing to cases involving the cost of environmental cleanup of manufactured gas plants and the cost of abandoned nuclear generation facilities, the Public Staff through witness Maness asserts that there is a "history" of sharing "extremely large costs that do not result in any new generation of electricity for customers." (Tr. vol. 15, 1562.) The Public Staff misreads these cases, but even more fundamentally, the Public Staff through this argument imports into the Public Utilities Act a notion ("extremely large costs") that simply does not exist in the Act. Referring in its 2018 DEP Rate Order to testimony from a Company witness who testified in the prior case, the Commission has already held:

> [T]here is "no provision of Chapter 62 requiring different treatment for 'extremely large costs'" (Tr. Vol. 20, p. 141), and, in any event, witness Wright detailed any number of "extremely large cost" items not associated with new generation for which cost recovery is routinely allowed. Id. ***This is yet another example of the arbitrariness inherent in the Public Staff's sharing proposal.***

((2018 DEP Rate Order, at 189-190) (emphasis added).) But, in any event, the Public Staff misreads and misapplies both the manufactured gas plant and nuclear abandonment cases, none of which have any relevance to the specific subject at issue – whether the Commission either may or must award the Company a return on the unamortized balance of CCR Costs during the Amortization Period.

a. MGP Case

The manufactured gas plant case (MGP Case) referenced by the Public Staff is the Commission's Order Granting Partial Rate Increase, Docket No. G-5, Sub 327 (October 7, 1994) (MGP Order). This case was addressed by the Commission in its 2018 DEP Rate Case Order. The Commission, noting that the precedent was of questionable validity in the first place, nevertheless held that it was distinguishable. (2018 DEP Rate Case Order, at 192-93.) In DEC's prior case, the Commission likewise found the MGP Order neither controlling nor persuasive. (2018 DEC Rate Order, at 277.)

There are indeed many distinguishing features between DEP's current case (and the coal ash cases generally) and the MGP Case. The coal ash cases involve asset retirement obligations arising from a change in legal requirements. AROs did not even exist in 1994, and the environmental cleanup costs at issue in the MGP Case did not arise in connection with asset retirement. As the Commission held in the 2018 DEC Rate Case Order, the MGP Case did not "address billions of dollars of CCR remediation costs incurred to comply with EPA and CAMA requirements accounted for in a deferred Commission approved ARO." (2018 DEC Rate Order, at 277) Moreover, basin closure costs or beneficiation facility construction costs are not "environmental cleanup" costs that were the subject of the MGP Case in any event. (*Cf.* id. ("The Commission is unable to discern whether the natural gas utility was required to construct lined landfills in which to place contaminated materials or construct caps over any existing repositories.").)

Further, the Commission noted that its ratemaking treatment gave the gas utility an incentive to minimize cleanup costs (MGP Order, at 23) – a factor not present in the coal ash cases, as coal ash costs are driven not by DEC or by DEP but by their environmental regulator, DEQ. Moreover, the Commission noted that its ratemaking treatment would incentivize the gas utility to pursue third-party contributions to cleanup costs. Multiple additional parties, prior owners of the sites in question, were potentially responsible under the applicable state and federal laws and regulations driving the need for environmental cleanup, for at least a share of the costs (id., at 20), and the Commission clearly did not want to dis-incent the gas utility from pursuing those parties by having customers pay the entirety of the costs. (Id. at 23.) Finally, the old MGP sites had not been operated in twenty years as of the time of the MGP Order, and so were clearly not "used and useful" in any sense – by contrast, CCR Costs are "used and useful" and a return consisting of financing costs on unamortized CCR Costs during the Amortization Period is therefore appropriate.

b. Abandoned Nuclear Plant Cases

The abandoned nuclear power generation cases – exemplified by *Utilities Comm'n v. Thornburg* (*Thornburg*)*,* 325 N.C. 484 (1989) – are similarly inapposite. They were also extensively discussed in the last round of rate cases. (*See*, *e.g.*, 2018 DEP Rate Order, at 190-92; 2018 DEC Rate Order, at 276, 280-83).)

In *Thornburg,* the Court concluded that the portion of common facilities at the Shearon Harris Nuclear Plant built to accommodate reactors that were later abandoned were excess facilities. Consequently, these excess facilities could not be included in rate base, because they were not used and useful. The coal ash cases do not involve excessive facilities tied to nuclear units that were never completed and never used to generated electricity. Instead, the coal ash cases involve investor-funded expenditures with a direct relationship to power generation – the utilities' system to address coal ash residue resulting from decades of electricity generation. When new regulations required changes to that system, investor funds were used to modify that system and those modifications were property capitalized as "electric plant utilities." Those investor funds that have been expended (and properly deferred by the Commission) are directly linked to property that was used and useful in rendering services to the public, and, as we have seen, are themselves used and useful in rendering service to the public.

In the 2018 Rate Order the Commission noted that as to the nuclear abandonment cases, to the extent relevant at all, their relevance goes to the propriety of "equitable sharing," not the return on any unamortized balance of CCR Costs. (2018 DEP Rate Order, at 190-92.) The Commission also noted that the Supreme Court rejected equitable sharing. (Id.)

The nuclear abandonment cases involve the utility's decision to make an investment that, for reasons unrelated to imprudence or mismanagement, becomes uneconomic. This was described by witness Fetter in his testimony, in the context of a hypothetical jurisdiction wrestling with the fallout of the Three Mile Island incident upon construction of nuclear generation. (DEC Tr. vol. 26, 145-46.) There may be good reason in such a circumstance to not visit the entire economic consequence of the investment decision upon customers, and the "used and useful" requirement – for those jurisdictions that have it – proved to be one means of ensuring that the entire economic consequence of an ultimately uneconomic investment be visited upon customers. (Id.)

CCR Costs are not an investment chosen by DEP or its management in the way that DEP chose to invest in (and then abandon for cost-effectiveness or other reasons) additional nuclear generation. To the contrary, CCR Costs are costs required by changes in the law – costs that the Company must incur, because failure to comply with the law is not an option for the Company. The nuclear abandonment cases, therefore, do not address the specific return issues with which the Commission grappled in DEP's prior case, or that the Commission is once again grappling with in this case. The Commission correctly decided in the 2018 DEP Rate Order that the nuclear abandonment cases were inapposite. Nothing has changed, and it comes to the same conclusion again.

E. Dominion Order

Some parties have cited to and relied upon certain portions of the Commission's 2020 Dominion Rate Order. Specifically, parties have cited to this Commission's determination that Dominion was entitled only to a recovery of but not on Dominion's CCR basin closure costs. This Commission notes, however, that the 2020 Dominion Rate Order does not govern the outcome of the present case. First, each rate case must be decided in consideration of the record evidence in that case. The record evidence in this case certainly supports a return on the unamortized balance of CCR Costs during the Amortization Period. Second, the Commission must in this case pay heed to the investor expectations embedded in the 2018 DEP Rate Order. There is nothing comparable with respect to the question of a return "on" for Dominion.

As the Commission stated in the Dominion Order, its decision was "based on the [Dominion] record as a whole … [and its legal conclusion was that] it is appropriate to treat the [Dominion] 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) … ." (2020 Dominion Rate Order, at 134.) The Dominion record included evidence that that Dominion's CCR costs were properly classified as operating expense. (Id. (Dominion witnesses indicated that roughly 98% of the deferred expenditures would have been classified as operating expense in the absence of ARO accounting).) There is nothing comparable in the evidentiary record in this case. To the contrary, as the Commission has already noted, both Company witnesses Doss and Riley testified that DEP's coal ash costs were all properly and appropriately classified as capital costs. Witness Doss specifically testified in this case, when provided with a copy of the Dominion Order noting Dominion's testimony that 98% of its costs were O&M indicated that to the contrary 100% of the Company's costs were capital. (Tr. vol. 17, 42-43.) There is no evidence to the contrary save Public Staff witness Maness' testimony that the costs are deferred expense – testimony that this Commission has already determined to be "not persuasive, not supported by authority and not determinative … [and] also incorrect as a matter of accounting." (2018 DEC Rate Order, at 289.)

Further, in the Dominion Order the Commission relied upon a number of historical studies of which it took judicial notice. (2020 Dominion Order, at 127-29 and 132.) These were not introduced into evidence during the evidentiary portion of the Dominion hearings. The situation in the current DEP and DEC cases is completely different – the cited studies, along with others, featured prominently in pre-filed testimony from multiple parties, and were heavily discussed and analyzed in the current cases, either directly (in DEC) or through stipulation (in DEP).

For example, among the cited studies are two EPRI manuals, *EPRI Coal Ash Disposal Manual* (2d ed. 1981) and *EPRI Manual for Upgrading Existing Disposal Facilities* (Aug. 1982), which were marked and introduced in the DEC case as, respectively, Joint Ex. 7 and Joint Ex. 8. Both EPRI manuals were the subject of extensive testimony from Company witness Williams, among others. (*See* Tr. vol. 19, 286-88.) Witness Williams indicates in her testimony that neither manual is particularly instructive with respect to the issues posed in this case.[61] The 1981 Manual, for example, is "written as guidance for designing new disposal facilities, not applicable to existing operating facilities" (id. at 286), and she noted specifically that the manual itself stated that EPA at that time had concluded that coal ash was "of relatively low concern." (Id.) As for the 1982 Manual, which focused on upgrading existing disposal facilities, she noted that the document itself announced at its very beginning that the applicable rules were in a state of flux, and that, therefore, "it may be premature for any utility to embark on a program to update their existing disposal facilities." (Id. at 287.)

Another of the historical studies referenced in the Dominion Order is the 1988 EPA Report to Congress (Joint Ex. 13). No matter what the earlier EPRI manuals may have said on the subject of coal ash management, the 1988 Report provided a comprehensive overview of coal ash management practices, and presented EPA's conclusions and recommendations regarding ash management. In short, the 1988 Report was "state of the art" for its time – and state of the art prepared by the very office at EPA led by witness Williams. If there is a single witness who lived that era at EPA who testified in this case, it is witness Williams. As she noted, in the 1988 Report EPA concluded that no change was necessary to then-current coal ash waste management practices, inasmuch as those practices "appear[ed] adequate for protecting human health and the environment." (Joint

[61] A later EPRI manual, published in 2004, was also referenced in the Dominion Order (at 128-29), and was discussed in detail above. It is also not instructive with respect to the issues posed in this case, as the discussion above concerning Georgia Power's Plant Arkwright shows.

Ex. 13 at 7-11.) And, as witness Williams also noted, EPA in crafting its 1988 Report was well aware that then-current waste management practices included, particularly in the Southeastern United States, unlined ash ponds. The Commission did too, in the 2018 DEP Rate Order.

The 1988 Report is instructive in other ways. In their references to the historical studies generally (Joint Exhibits 1-13) intervenors ignored the conclusions reached by any particular study and merely cherry picked an individual sentence or two from the study that they felt advanced some argument they were making. Witness Quarles provides an object example. His pre-filed testimony cited to the 1988 Report, and stated that a "key conclusion" of that Report was that "The primary concern regarding the disposal of wastes from coal-fired power plants is the potential for waste leachate to cause groundwater contamination." (Tr. vol. 14, 599.)[62] But, as witness Quarles admitted on cross-examination that "key conclusion" is nowhere to be found in the actual conclusions of the Report, which were set forth in Chapter 7 of the Report. (Tr. vol. 14, 682-683.) Witness Quarles' treatment of the 1982 EPRI Manual (Joint Ex. 8) is similar. In his pre-filed testimony he quotes from the Manual:

> In 1982, EPRI made clear that regulatory compliance by itself might not ensure environmental protection and advised that utilities must achieve both, noting that "[p]otential deficiencies in utility waste disposal practices may be defined by two sets of standards: [1] The disposal practice does not comply with specific federal and/or state regulatory requirements; [2] The site has the potential to contaminate the environment." (1982 EPRI Manual at 4-1.) Accordingly, EPRI reached this conclusion: "[a]n engineering assessment of site adequacy must therefore address (1) whether the operation complies with prevailing regulations, and (2) whether the site poses a threat to the local environment. Both problems must be addressed simultaneously." (1982 EPRI Manual at 4-2.)

(Tr. vol. 14, 601.)

The obvious inference from the quotation that witness Quarles wished to draw is that simply complying with environmental regulation is not necessarily good enough, one must in addition do more than merely comply when a site poses the threat of environmental "contamination." But what the authors of the Manual meant by "contamination" is very important to a full understanding of what their recommendations meant – and no one, certainly not witness Quarles, knows what they meant by "contamination." (Id. at 659-660.) This is a key distinction, because whether "contamination" is of the type that could cause environmental harm – that is, harm to the public health and welfare, for example by threatening drinking water – or is merely a

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[62] Witness Quarles presented exactly the same testimony to the Georgia Public Service Commission in Georgia Power's last rate case (*see* Tr. vol. 14, 717-18; Quarles DEP Cross Examination Ex. No. 2, at 7), and the Georgia Commission rejected it. Georgia is one of the jurisdictions that provide for both recovery "of" and a return "on" coal ash costs. (Tr. vol. 19, 64; DEC Tr. vol. 26, 80, 138.)

regulatory issue is crucial to fashioning an appropriate response, as witness Wells testified. (Tr. vol. 19, 1561-62.) Public health risk requires quicker action; a regulatory issue alone requires working with the regulator – in this case, DEQ – to fashion an appropriate solution. DEP did both.

Moreover, in the 1981-82 period in which the EPRI Manuals were published, the evidence in DEP's case proves that DEP, in the face of the types of concerns regarding the potential for environmental contamination from ash ponds, investigated its ponds. The Company had by then already undertaken significant groundwater investigations at its Roxboro and Mayo plants, investigations that showed no significant groundwater impact; indeed, the Floyd Report's conclusion regarding Mayo – a conclusion which witness Quarles ignores completely – was that "it is difficult to imagine that any significant adverse impact on the ground water aquifer could be caused by ponding of the ash wastes at the proposed site." (Floyd Report, at 15.) Monitoring it embarked upon at Sutton in the mid-1980s also showed no significant impact.

These studies – DEP's internal work, performed on a voluntary basis, and Arthur D. Little's work performed on behalf of EPA – concluded that the wet sluicing of coal ash to Piedmont region ponds did not have a significant impact to groundwater: "And the key conclusion, not just from Duke's internal voluntary work … [but also the] A. D. Little work, was the same. And that is the impacts were localized, they weren't seeing a risk, they weren't seeing a significant impact." (Id. at 391.) Witness Quarles chose to ignore the conclusions of the actual studies, as reported in their executive summaries. Instead, he called the conclusions "bad information." (Tr. vol. 14, 66.)

Witness Quarles and other intervenor witnesses may have the luxury of ignoring the actual findings of the studies they bring to the Commission's attention, or cherry picking from massive studies to fixate on a random sentence or two within them. The Commission does not. Should it choose to rely on evidence such as technical reports and scientific literature, it must thoroughly review the reports and literature, not review them in a cursory manner. It must take into account negative evidence from the reports and literature, not simply sweep such "evidence under the rug." *National Audubon Society v. Department of the Navy*, 422 F.3d 174, 194 (4th Cir. 2005). If it fails in these tasks, it risks a reviewing court finding it to have acted arbitrarily and capriciously. (Id. at 187.)

The second reason not to import the Dominion case result into this case is the fact that investor expectations were not embedded into the Commission's prior rulings with respect to Dominion's CCR costs. Unlike DEP's current situation, Dominion's prior case (decided in 2016, in Docket No. E-22, Sub 532) was not fully litigated and did not have a significant evidentiary record (2020 Dominion Rate Order, at 123), and so the Commission minimized the prior case's precedential effect. (Id.) The Commission's decision in Dominion's prior case certainly did not have any language even remotely similar to the language in the 2018 DEP Rate Order that creates investor expectation – the language quoted above and re-quoted here that did not merely endorse spend/defer/recover but requires it, and the language that indicates that in future cases, barring a future finding of imprudence, the Commission "will" authorize a return "on" incurred and deferred CCR Costs brought into rates over time in an Amortization Period:

… CCR remediation costs incurred by DEP during the period rates approved in this case will be in effect shall be booked to an ARO that shall accrue carrying costs at the approved overall cost of capital approved in this case (the net of tax rate of return, net of associated accumulated deferred income taxes). The Commission will address the appropriate amortization period in DEP's next general rate case, and, unless future imprudence is established, will permit earning a full return on the unamortized balance.

(2018 DEC Rate Order, at 206.) The Company's next general rate case is this case. The Commission will decide the appropriate amortization period over which CCR Costs are to be brought into rates. But the Commission needs to hew to its promise that a full return – a WACC return – be earned on that balance. It does so.

Discussion of Question #4: Discrete Fault-Based Disallowances and Public Staff Prudence Disallowances

Discrete Fault-Based Disallowances

Alleged Environmental "Violations"

The Public Staff, through witness Lucas, asserts that disallowance of the Company's costs related to groundwater at Asheville and Sutton, as well as the purchase of land to mitigate exposure at the Mayo plant, is justified because these costs flow from "violations" of the law. In addition, the Public Staff and the AG, through witness Hart, assert that the Commission should disallow costs related to provision of permanent water supplies for similar reasons. Both are a continuation of the fault-based culpability standard and fail to substantiate a disallowance. As discussed previously in this Order, the Commission rejects the Public Staff's and AG's proposed fault-based disallowances as the evidence does not support a finding that DEP violated the law, nor does it support a finding of imprudence with respect to these costs. This finding is consistent with the Commission's 2018 DEP Rate Order, in which the Commission found that the costs related to groundwater extraction and alternative water supplies were prudently incurred and, accordingly, recoverable in rates.

1. Groundwater Treatment Costs

As Company witness Bednarcik explains, the Company has incurred a total of $1,240,328 related to its extraction well system at the Asheville and Sutton plants and its purchase of land adjacent to the Mayo plant intended to mitigate groundwater exposure pathways. The vast majority of these costs, including land acquisition costs at Cape Fear and H.F. Lee, were recovered as part of the 2017 Rate Case, and the Company is now seeking to recover the remaining costs in the instant case. (Tr. vol. 17, 131.) Notwithstanding that the Commission already found these very same costs to have been prudently incurred and recoverable in the previous rate case, the Public Staff, through witness Lucas, asks the Commission to take a "fresh look" at its treatment of these expenses.

The premise of witness Lucas's argument for disallowance of these costs, however, is nearly identical to the one he advanced on behalf of the Public Staff in 2017 – that the Company's installation of extraction wells at Asheville and Sutton pursuant to the terms of the September 2015 Settlement between DEQ, DEC, and DEP (the Sutton Settlement Agreement) and the purchase of land at Mayo would not have been necessary under CAMA absent violations of the state's groundwater standards. The Commission has already rejected this rationale once. As witness Lucas acknowledges in his testimony, the Commission's 2018 DEP Rate Order stated that "[t]he Commission determines that there is insufficient evidence that the Company would have had to have engaged in any groundwater extraction and treatment absent the obligations imposed upon it by CAMA and/or the CCR Rule." (2018 DEP Rate Order, at 183.) In so holding, the Commission noted that "unlike the 2L Rules, CAMA requires utilities to perform groundwater assessment and corrective action for all identified exceedances of the 2L groundwater standards regardless of whether the exceedance amounts to a violation of the applicable groundwater standard." (Id. at 183.). Likewise, in the 2018 DEC Rate Order, the Commission found that "the assertion that DEC's 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." (2018 DEC Rate Order, at 300.)

Consistent with both the 2018 DEP Rate Order and the 2018 DEC Rate Order, the Commission again declines to find that the DEQ Settlement Agreement evidences violation of environmental obligations. As noted in the Commission's 2018 DEC Rate Order, the DEQ Settlement Agreement references in its recitals a DEQ "Policy for Compliance Evaluations" promulgated in 2011, and it appears from the recitals and their description of that Policy that there was a very serious question as to whether any violation of the State's groundwater standards had occurred. (*See* DEQ Settlement Agreement, at 3, 4-5.) The recitals also indicate, with the passage of CAMA, that the Company would be required to close its coal ash basins, and that CAMA "dictate[d], in detail a procedure for assessing, monitoring and where appropriate remediating groundwater quality in areas around coal ash impoundments in North Carolina …." (Id. at 3-4.) Further, in the recitals the DEQ acknowledged that the CAMA requirements were "designed to address, and will address, the assessment and corrective action" associated with alleged groundwater contamination.

In support of his contention that the Commission should reverse course on its previous ruling, witness Lucas points to the fact that groundwater exceedances measured at four DEP plants have increased from 1,698 in 2017 to 3,495 today. (Tr. vol. 15, 1501.) In response, Company witnesses Bednarcik and Wells contend that witness Lucas's reliance on these numbers is indicative of a basic misunderstanding of the 2L exceedance/violation process. (Tr. vol. 17, 132.) According to witnesses Bednarcik and Wells, an increase in measured exceedances does *not*, as witness Junis contends, suggest an increase in groundwater contamination in and around the Belews Creek plant. Rather, the increased number simply indicates that sampling is ongoing at both pre-existing and new wells while the Company engages in preparing and implementing a corrective action plan in cooperation with DEQ and as required under CAMA. In this way, witnesses Bednarcik and Wells explain, an increased number of exceedances is not unexpected while the Company works with DEQ toward corrective action, but instead represents an effort to define the shape of the plume. (Id.)

The Commission finds the testimony of Company witnesses Bednarcik and Wells to be credible and entitled to substantial weight given both witnesses' history of compliance work for the Company. In particular, the Commission is persuaded by the testimony of witnesses Wells and Bednarcik that the Public Staff's focus on the raw number of exceedances measured over time ignores the iterative nature of comprehensive site assessment, highlighting the Public Staff's fundamental misunderstanding of both the corrective action process and the Company's relationship with NCDEQ. As witness Wells explained, measuring exceedances at different locations in a plume around an activity may result in multiple exceedances of groundwater standards, but that does not result in multiple violations of the 2L rule's prohibition. Both he and witness Bednarcik explained that this distinction is important for evaluating the claim that the number of exceedances indicates a "breadth of environmental violations." (Tr. vol. 17, 168.) On the other hand, witness Lucas, who has no experience working with environmental regulators, fails to offer any compelling reason why the Commission should look at each instance of a measured exceedance outside the context of identifying the plume. For these reasons, the Commission declines to adopt the Public Staff's proposed disallowance for groundwater treatment costs.

2. Permanent Alternative Water Supplies

Both the Public Staff and AG recommend that the Commission disallow recovery of costs that DEP incurred to provide permanent drinking water supplies to neighboring properties. The Public Staff, through witness Lucas, calculates the amount to be disallowed as $3,862,195, which calculation includes both the costs incurred to connect eligible residential properties to permanent alternative water supplies *and* the costs incurred to install and maintain water treatment systems. (Id. at 85.) The AG calculates its proposed disallowance to be $3,481,096. (Tr. vol. 16, 826; Tr. vol. 17, 38-39.) For the reasons set forth below, the Commission is not persuaded by either the Public Staff's or the AG's arguments and declines to adopt the proposed disallowances.

For his part, Public Staff witness Lucas argues only that the permanent alternative water supply expenses are analogous to the costs the Company incurred to provide temporary bottled water supplies to customers—expenses which the Commission disallowed in the 2018 case—and should, therefore, be disallowed. (Tr. vol. 15, 1503-04.) In response, witness Bednarcik notes that DEC's efforts with respect to installation of permanent alternative water supplies and water treatment systems were undertaken to comply with applicable law. (Tr. vol. 17, 133.) In particular, N.C.G.S. § 130A-309.211(c1) obligated the Company to establish permanent replacement water supplies for each household that has a drinking water supply well located within a one-half mile radius from the established compliance boundary of a CCR impoundment, and is not separated from the impoundment by a river. The statute goes on to provide that the requisite replacement water supply can be achieved either through connection to public water supplies or, in certain circumstances, through installation of a filtration system at the household. Witness Bednarcik notes that the requirement exists even absent the existence of a 2L exceedance for qualifying households and also applies to households outside the half-mile radius where such exceedances were identified. Finally, witness Bednarcik points out, and witness Lucas acknowledges, that the Company is not seeking to recover the costs it voluntarily incurred to connect uncovered properties to alternative water supplies that were not subject to the requirements of CAMA. (Id. at 134.)

The Commission finds witness Bednarcik's testimony to be credible on its face. DEP complied with the letter of the law with respect to installation of permanent alternative water supplies and water treatment systems. Accordingly, the Commission sees no compelling reason presented by the Public Staff to depart from its position in the 2018 Rate Case Order that these costs are recoverable.

Turning to the AG's argument, witness Hart contends that alternative water supply costs were incurred directly as a result of DEC delay in evaluating groundwater impacts to potential receptors at its sites. (Tr. vol. 13, 712.)

Witness Hart does not dispute that CAMA was amended in 2016 to require DEC to provide alternative drinking water supplies to residents within a half mile of its impoundments. Further, witness Hart does not dispute that DEC is required to comply fully with CAMA and its amendments. Instead, witness Hart's recommended disallowance is based on his speculation of *why* the North Carolina legislature included the requirement. It would be improper for the Commission to engage in such speculation:

> Even if the actions or inactions of [DEC] or one of its sister companies was a direct cause of CAMA as these witnesses allege, such direct causation alone is not sufficient legal basis for disallowing otherwise recoverable costs. If the North Carolina General Assembly had intended to give the Commission the authority to deny otherwise recoverable environmental compliance costs due to some punitive theory of causation, it could have said so—and it did not.

2017 DEC Order at 272. Even if the Commission were to engage in witness Hart's mind-reading exercise, his theory rests on flimsy grounds. Months prior to the adoption of the CAMA amendment, the Executive Branch agency responsible for public health, the Department of Health and Human Services (DHHS) rescinded drinking water advisories for properties near DEP's sites determining that ash basins did not pose a risk to the safety of residents' drinking water. (Tr. vol. 17, 47-50.) The legislature, nevertheless, determined that further protections were needed. But had lack of reliable data been the motivating factor for the legislature's inclusion of this requirement, as witness Hart suggests, certainly being presented with conclusive data showing no contamination of receptor wells would have caused the legislature to rescind this requirement. (Tr. vol. 18, 119.) The legislature has not done that, which shows the folly in attempting to ascribe motive or intent to legislative policy decisions in the absence of any express statement of intent.

Public Staff's Prudence Disallowances: Overview

The Commission's framework requires a detailed analysis before any costs can be disallowed on the basis of findings of imprudence. (2018 DEP Rate Order, at 141.) The Public Staff attempts such an analysis of the Company's coal ash costs, and based on that analysis presents several discrete and specific proposed sets of disallowances. Through the testimony of witnesses Garrett and Moore, the Public Staff argues that the Company acted imprudently and unreasonably with respect to management of CCR compliance activities at the Sutton, Cape Fear, Weatherspoon, H.F. Lee, and Asheville plants, and contends that the Company should have selected different management approaches and/or different approaches to contractual negotiations, thereby saving costs. In particular, the Public Staff recommends the following disallowances: including: (1) payment of a fulfillment fee to Charah related to the planned disposal of ash from the Sutton, Cape Fear, Weatherspoon and H.F. Lee plants at the Brickhaven structural fill ($33,670,054) (Tr. vol. 17, 85.); (2) payment of purported excess costs for transportation of ash from the Asheville plant to Waste Management's R&B landfill in Homer, Georgia ($50,238,630.); and (3) construction costs at the H.F. Lee and Cape Fear beneficiation plants ($130,384,392). (Id.)

After consideration of the record, the Commission determines not to accept these discrete disallowances based upon the testimony of Company witness Bednarcik which the Commission credits and to which the Commission attaches substantial weight. Historically – and, in particular, in the 2018 DEP Rate Order, the 2018 DEC Rate Order, and the 1988 DEP Rate Order – this Commission has stressed the importance of carefully examining the Company's explanations of the decisions it made, as of the time they were made, and emphasized the credibility of the decision-makers, particularly in juxtaposition to after-the-fact analyses presented by intervenor-retained consultants. (*See*, *e.g.,* 2018 DEP Rate Order at 186-87; 2018 DEC Rate Order at 302; 1988 DEP Rate Order, at 29.) The Commission is persuaded by witness Bednarcik's testimony that Garrett and Moore missed or overlooked pertinent facts and real world conditions in their recommendations, and that their discrete disallowances are therefore unwarranted.

Like witness Kerin's testimony in the 2018 case, witness Bednarcik's testimony regarding the Company's decisions is entitled to substantial weight – more weight than after-the-fact evaluations from Garrett and Moore. Witness Bednarcik expressed a full and complete understanding of the issues, which is not surprising given her background. She has been "living and breathing" the CCR closures in her role as Vice President of Coal Combustion Products, Operations, Maintenance, and Governance, overseeing the Company's compliance program. (Tr. vol 15, 66; Tr. vol 17, 79-80.) Additionally, witness Bednarcik's expertise regarding the Company's federal and state regulatory obligation related to CCR storage facilities and CAMA were further bolstered by her command of the current and historical operations of the Company's CCR storage facilities, her significant and ongoing engagement with pertinent current and former employees with direct responsibility for CCR storage, and her commitment to the governance and accountability of the Company's compliance program. (Tr. vol. 15, 255-61; Late Filed Exhibit 7 (listing Duke Energy employees and former employees who informed witness Bednarcik's testimony, knowledge, and understanding of the Company's current and historic environmental compliance and coal ash practices).) Witnesses Garrett's and Moore's recommended disallowances were challenged at the hearing through cross-examination. These witnesses were unable effectively to support their positions while on the witness stand. Similar to the Commission's findings in Docket No. E-2, Sub 1142, witnesses Garrett and Moore have once again "overlooked pertinent facts and real-world conditions in their recommendations." (DEC 2018 Rate Order, at 302.) Therefore, the Commission determines that their recommendations are deficient on the basis of a lack of credibility.

Payment of Charah Fulfillment Fee

On behalf of the Public Staff, witness Garrett argued that the $80 million fulfillment fee paid to Charah pursuant to eMax Master Contract Number 8323 (the Charah Master Contract) on behalf of both DEP and DEC was unreasonable and imprudent, and therefore recommended a disallowance for DEP in the amount of $33,670,054. Neither witness Garrett nor any other intervenor challenges the prudency of the Company's decision to contract with Charah. Accordingly, the sole issue before the Commission with respect to the Company's engagement of Charah is whether the fulfillment fee the Company paid to Charah pursuant to the contract terms was reasonable.

By way of background, witness Bednarcik explained that the Companies executed the contract with Charah on November 12, 2014, with the intent of securing a location at which to dispose of approximately 20 million tons of CCR from DEP's Sutton, Cape Fear, H.F. Lee, and Weatherspoon plants and DEC's Riverbend plant. (Tr. vol. 17, 88-89.) Time was of the essence to secure such a location according to witness Bednarcik because both the Riverbend and Sutton sites were classified as "high priority" sites under CAMA with an excavation deadline of August 1, 2019. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Nearly two years after the Companies executed the contract with Charah, the North Carolina Legislature passed an amendment to CAMA that required the Company to construct beneficiation units capable of converting 300,000 tons of ash a year for use in the cement industry at three Duke Energy Plants. (Id. at 90, 231.) Between December 2016 and June 2017, the Companies announced that Buck, H.F. Lee, and Cape Fear would serve as the three beneficiation sites (Id. at 90, 168.), an arrangement witness Bednarcik explains severely reduced the ash available for transport to the Brickhaven and Sanford Colon mines. (Id.) As a result, the contract was deemed terminated on May 29, 2019 after just 7,342,409 tons of ash had been actually excavated and triggering the fulfillment fee provisions. (Id.)

For its part, the Public Staff, through witness Garrett, contends that the fulfillment fee was unreasonable because it was calculated using what witness Garrett believes was an incorrect denominator. And for reasons described in more detail below, the Commission is not persuaded by this argument, and instead gives substantial weight to the justification provided by witness Bednarcik.

First, witness Garrett's purported calculation methodology disregards the plain language of the contract and improperly attempts to re-write a key provision. **[BEGIN CONFIDENTIAL]** [redacted]

> [redacted] **[END CONFIDENTIAL]**

Witness Garrett acknowledged on cross-examination that the Master Contract explicitly lays out the appropriate calculation of the prorated cost as negotiated by the Parties, leaving no ambiguity.[63] (Tr. vol. 15, 1359-60.) Yet despite this clear language, witness Garrett proposes an alternative calculation, essentially supplanting the contractual terms of a provision fully negotiated between two sophisticated Parties with his own terms. (Id. at 1361.) **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

By suggesting that the Commission interpret the Charah contract in a way that is contrary to the plain language of the document, witness Garrett's proposal demonstrates a fundamental misunderstanding of general principles of contractual construction. *RL REGI N.C., LLC v. Lighthouse cove, LLC*, 367 N.C. 425,428, 762 S.E.2d 188, 190 (2014) (finding that the court looks to "the plain meaning of the written terms" in order to "determine the intent of the parties."); *Ussery v. Branch Banking & Tr. co.*, 368 N.C. 325, 335, 777 S.E.2d 272, 279 (2015) (finding that the meaning of a contract is "gathered from its four corners."). Moreover, the Commission notes that the law is clear in North Carolina that when sophisticated parties like Duke and Charah engage in a protracted negotiation process where each party has equal bargaining power to alter language ambiguities are not, as a rule, construed against the drafter and, instead, terms are given the meaning

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[63] Witness Garrett gave live testimony regarding the fulfillment fee paid to Charah on behalf of DEP and DEC in the DEC-specific hearings, and his articulation of the Public Staff's position in that hearing is made part of the DEP Record through the Amended Stipulation.

the parties intended. *Joyner v. Adams*, 87 N.C. App. 570, 361 S.E.2d 902 (1987) (rejecting the rule to construe ambiguities against the drafter because "the language was assented to by parties who had both the knowledge to understand its import and the bargaining power to alter it.")

Here, as witness Bednarcik explained, both Duke and Charah negotiated at arm's length the appropriate inputs for the prorated cost calculation.[64] (Tr. vol. 17, 314.) Further, the termination provisions of the Master Contract were carefully tailored to ensure that the development cost at Brickhaven and Sanford Clay Mines were appropriately apportioned between the parties. Thus, the 20 million denominator is the correct number for calculating the prorated percentage and, by extension, the prorated costs. (Id. at 288.) Witness Garrett cannot now replace one contractual term for another post execution, and the Commission rejects his proposed disallowance on those grounds.

Moreover, the Commission finds, consistent with witness Bednarcik's testimony, that there are several other provisions in the contract that support the as-written formula for pro-rated costs. **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[redacted]

[redacted]

[64] Witness Bednarcik gave live testimony regarding the fulfillment fee paid to Charah on behalf of DEP and DEC in the DEC-specific hearings, and her articulation of the Company's position in that hearing is made part of the DEP Record through the Amended Stipulation.

[redacted] **[END CONFIDENTIAL]**

Second, even if it were possible to *ex post facto* rewrite the contract as witness Garrett suggests, the Commission is persuaded by witness Bednarcik that the Public Staff's proposal for calculating the fulfillment fee likely would not have induced Charah – or *any* qualified contractor – to enter into the contract for ash disposal. As witness Bednarcik explained, for a contractor to invest a large amount of capital, such as in the development of significant infrastructure in order to be able to perform the needed contracted service, it is common practice and reasonable to require a minimum investment by the company requesting the contracted service. (Tr. vol. 17, 212.) **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

The Public Staff, both through witness Garrett and cross-examination of witness Bednarcik, attempted to assert that Charah had already recovered its development costs through payment of the purchase orders issued under the Master Contract and that payment of the fulfillment fee duplicated its cost recovery. However, witness Bednarcik's testimony is clear that Charah did not recover twice for the cost of development. (Id.) **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** As witness Bednarcik explained, while some portion of Charah's sunk development cost was paid through purchase orders, the vast majority of it was recovered through the fulfillment fee. (Id.)

Moreover, witness Garrett's proposal for calculating the fulfillment fee would work an absurd result, compensating Charah for a small fraction of a fraction of its sunk costs. **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]** To assume any competent commercial entity would have undertaken development, purchased two mines, developed a rail delivery system without any substantial assurance of cost recovery for such investment is unreasonable. (Id.)

Although Public Staff attempted to question whether Charah incurred cost at the Sanford Mine, witness Bednarcik affirmed that Charah indeed incurred development costs, including purchase of the mine, site closure and post closure costs for compliance to comply with the Sanford Mine's Mine Reclamation Permit. (Tr. vol 17, 92.) Because the Sanford site is a mine and not green fields, Charah must manage storm water, acquire permits and revisions to permits, and keep the site in a safe state and in compliance with environmental regulations (Tr. vol. 25, 22). Thus, Charah will incur cost for the Sanford mine site regardless of whether ash was ever delivered to the site, making it wholly appropriate to allocate cost to DEP. (Tr. vol. 25, 20-21). Additionally, as witness Bednarcik explained the cost for the Sanford Mine was only 12% of the total fulfillment fee. (Tr. vol 17, 92).

Likewise, witness Garrett's contention that the Prorated Cost amount should be fully allocated to DEC fails. Witness Garrett contends that because the planned quantities of ash from Sutton were transported to the Brickhaven mine and there was no ash transported from Riverbend to Brickhaven mine or purchase orders issued for Cape Fear, Weatherspoon, or H.F. Lee, there should be no allocation of cost to DEP. (Tr. vol.15, 1228-29, 1248-49.) As discussed previously in this Order, the contract with Charah was intended to reserve capacity for 20 million tons of ash. The fulfillment fee provision and calculation methodology likewise is intended to make Charah whole for the cost it incurred to prepare both sites to store the ash for DEC and DEP. (Tr. vol 17, 92.) The Company's allocation of the fulfillment fee in this case to DEC and DEP fairly allocates the fulfillment fee based upon the tonnage of ash anticipated to be sent from each site to Brickhaven and Sanford mines. (Tr. vol. 25, 250; Bednarcik Rebuttal Exhibit 3.) This approach is entirely consistent with allocating the cost based upon the capacity that was reserved for use for the companies. Furthermore, the Commission is not persuaded by witness Garrett's alternative recommendation to adopt the methodology for allocating the fulfillment fee presented in the DEP's 2017 spreadsheet. (Tr. vol.15, 1250.) As witness Bednarcik testified, the spreadsheet was created before DEP had any idea of Charah's actual total development costs and was only a rough order of magnitude estimate (Tr. vol. 25, 100.)

Finally, witness Garrett failed entirely to rebut witness Bednarcik's testimony that the Company took reasonable steps to mitigate the potential magnitude of the fulfillment fee, both through the crafting of protective contractual terms and negotiations following termination. **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]** The Commission gives significant weight to witness Bednarcik's testimony that Duke Energy negotiated these provisions to mitigate the fulfillment fee based on various stages of Charah's site development to further protect the Company and its customers, (Id.) and notes again that, where there is ambiguity, North Carolina law does *not* impose an inference against the drafter where, as here, both parties were sophisticated, arms-length negotiators with equal bargaining power. *Joyner*, N.C. App. at 570, 361 S.E.2d at 902.

When the fulfillment fee was triggered, the Company went beyond the bargained for caps in seeking to mitigate exposure and initiated negotiations to further reduce the final fulfillment fee. (Id.) **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** In that regard, the agreement fully contemplated a process to review and negotiate the cost that would be subject to the prorated cost provision. This contracting approach is not unusual in this commercial context and was necessary due to the inability to fully identify each and every potential item of prorated cost at the inception of the contract. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Thus, as contemplated by the Contract, Duke Energy was provided documentation to support the costs Charah included in the prorated cost calculation. Charah included costs they considered appropriate and for which they were seeking reimbursement under the criteria of land acquisition, development, closure, post-closure monitoring and leachate collection and disposal costs. Ultimately, the Companies secured an agreement for a final fulfillment fee of $80 million, $10 million less than the $90 million cap.

In sum, witness Bednarcik's testimony demonstrates that the Company's actions and real time decisions negotiating the Charah Master Contract and post-termination fulfillment fee were in fact reasonable and prudent, and the fulfillment fee cost was prudently incurred to allow the Company to proceed with beneficiation as required by CAMA. The Commission therefore rejects the Public Staff's proposed disallowance of the fulfillment fee.

Purported Excess Costs to Transport Ash from Asheville to R&B Landfill

Witness Garrett next argues that the purportedly "excessive" costs the Company incurred to transport 1,651,500 tons of ash from Asheville to Waste Management's permitted R&B Landfill in Homer, Georgia between September 1, 2017 and December 31, 2019 ($50,238,630) should be disallowed. As witness Garrett acknowledges, (Tr. vol.

15, 1260.), this Commission approved rate recovery of DEP's costs to transport CCR from Asheville to the R&B Landfill in Docket No. E-2, Sub 1142. 2018 DEP Rate Order, at 183-87. These approved costs included costs to transport CCR from both the 1982 Ash Basin and the 1964 Ash Basin to the R&B Landfill pursuant to purchase orders DEP issued to Waste Management dated October 2015 and November 2016. The costs for which the Company is currently seeking reimbursement were incurred pursuant to those same purchase orders (Tr. vol. 15, 1394.) Accordingly, and consistent with 2018 DEP Rate Order precedent, the Commission again finds that the costs to transport excavated ash from Asheville to the R&B landfill were reasonably and prudently incurred and that the Company may recover in full its CCR remediation costs at Asheville.

Notwithstanding clear Commission precedent, witness Garrett urges the Commission to reconsider its position because of a purported "material change in facts." (Tr. vol. 15, 1260.) In particular, witness Garrett suggests that witness Bednarcik's testimony in the current case that the Company plans to construct an onsite landfill at Asheville belies the testimony of Company witness Jon Kerin in the 2017 case that an onsite landfill was not feasible at Asheville for a number of reasons, including seismic issues and the site's proximity to the French Broad River. (Id. at 1262.) With this purportedly "new" information, witness Garrett suggests that the Company could have avoided the significant costs of ash transport by either constructing and onsite landfill years earlier or transporting ash to the Company's existing landfill at Cliffside. Yet again, however, the Commission finds that witness Garrett's position ignores real world obstacles to accomplishing either of his proposals.

As a threshold matter, the Commission disagrees with witness Garrett's characterization that a "material change" has occurred such that this issue should be revisited. Indeed, witnesses Garrett and Moore testified in Docket No. E-2, Sub 1142 that the Company should have pursued an onsite industrial landfill "capable of storing 3 million tons of CCR" to potentially avoid offsite hauling cost at Asheville (Tr. vol. 15, 1399-1400.) In Docket No. E-2, Sub 1142, witness John Kerin responded for DEP that it was not technically feasible to build a landfill of appropriate size that could handle three million tons of ash at the Asheville site. (Id. at 1401.) That was true in 2017 and, according to the informed testimony of witness Bednarcik, remains true today. In explaining the technical infeasibility, witness Kerin went into great detail regarding the challenges of building a three million ton capacity landfill within the confines of the Asheville site, while also building a combined cycle plant pursuant to the Mountain Energy Act. There has been no reasonable evidence presented in this case that supports a conclusion that witness Kerin's testimony was incorrect or false. Indeed, in the present case, witness Bednarcik reaffirms the infeasibility of constructing a three million ton onsite landfill at Asheville. (Tr. vol. 17, 419-20.) Specifically, witness Bednarcik points out that the onsite landfill the Company is currently constructing at Asheville will accommodate only 1.3 million tons of ash and, at best, could accommodate less than one third of the remaining ash to be excavated at Asheville as of September 1, 2017. (Tr. vol. 17, 104-05.) Given site limitations at Asheville, including wetlands, property buffers, and topography, the Company had to employ state of the art technology to construct the landfill, and, according to witness Bednarcik, it would not be feasible for the Company to increase capacity in any way. (Id. at 105.) Moreover, as witness Bednarcik points out, construction of an onsite landfill of any size would not have been feasible before 2020. Thus, the 1.3 million ton landfill that is currently under construction and the basis of witness Garrett's "material change" could not have been constructed prior to 2020, and will not be complete until 2021.

Witness Bednarcik walked through the multiple obstacles impeding the ability to develop a landfill onsite. In June 2015, the North Carolina General Assembly passed the Mountain Energy Act, which required the Company to construct a combined cycle plant at Asheville by January 31, 2020 to replace the site's coal-fired units. (Id. at 107.) Construction of the plant took up valuable space on the Asheville property that was already limited in size and geography. The testimony of witness Bednarcik depicts the congestion at the site by identifying four discrete quadrants that highlight the obstacles to pursuing an onsite landfill prior to completion of the combined cycle plant. This includes the active coal plant, the 1964 basin, the site of the new combine cycle plant, and the laydown area for construction of the combined cycle plant. (Id. at 108.) As was thoroughly discussed by the Commission in the 2018 DEP Rate Order, the new combined cycle plant was built on the site of the Asheville plant's basins. This meant 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 onsite landfill. (2018 DEP Rate Order, at 186.)

Similarly, witness Bednarcik explained in this case that she was intimately involved in the Asheville work – from the handling of the ash that was being produced at the active coal power plant, the construction of the combined cycle, and the laydown area made it a physical impossibility to construct an onsite landfill (Tr. vol. 17, 428.) In her words, "anyone who actually visited the site while all that work was going on and seeing what you would need and the volume of the area that was needed to do all of that, it could not be done." (Id.) Furthermore, the infeasibility of a three million ton landfill was confirmed during the planning and design of the new landfill - making offsite disposal a necessity (Tr. vol. 17, 110.) The Commission thus affords substantial weight to witness Bednarcik's testimony that there simply was not space to construct a new onsite landfill while construction of the combined cycle plant was ongoing. (Id. at 109.)

In the face of this testimony, the Public Staff failed to provide any evidence (e.g., designs, plans, schematics, etc.) that a three million ton capacity landfill could have been constructed given the constraints at Asheville at any time. Indeed, witness Garrett advocates for a "fresh look" on an issue already decided by this Commission in a prior case, but provides no new evidence upon which to justify a "fresh look". In fact, it was Public Staff's own recommendation in the Company's 2018 rate case that "on an ongoing basis we believe DEP should further evaluate other lower cost remediation options for the remaining ash on site (Asheville)." (Tr. vol. 15, 1425.) In this case, witness Garrett agreed that the identification of a potential on-site landfill at this phase of the Asheville excavation is an example of the Company continuing to evaluate, and when feasible, implementing a cost-effective closure option. (Id. at 1425-26.) Based on the evidence presented in this case, it appears that the Company has done nothing more than what the Public Staff itself has asked the Company. Thus, we are not persuaded to reconsider our well-reasoned decision on that basis. The Commission is similarly unconvinced by the Public Staff's argument that DEP should have transported ash to Cliffside rather than the R&B landfill. From a technical standpoint, the Commission is persuaded by witness Bednarcik's testimony that the R&B Landfill provided two distinct advantages over Cliffside. First, transportation from Asheville to R&B Landfill could be accomplished on an established trucking route that primarily traversed interstate highways. The route to Cliffside, on the other hand, included approximately eight miles of two-lane country roads. The impacts to the community around Cliffside resulting from the truck traffic needed to dispose of 1.6 million tons of ash would not have been trivial. (Id. at 114.) Second, the Company could preserve the Cliffside landfill's primary responsibility, which was to store CCR from Cliffside. If the Company overcommitted off-site ash to Cliffside, thereby leaving less capacity for Cliffside ash, the benefits of having an on-site landfill there would be rendered meaningless. (Id.)

For all of these reasons, the Commission determines that witness Bednarcik's testimony demonstrates that the Company's actions and real-time decisions regarding the Asheville site were in fact reasonable and prudent in the context of the CAMA deadline and the MEA mandate to construct a combine-cycle plant, and the costs were therefore prudently incurred. As such, no discrete disallowance is approved and the Commission declines to impose the disallowance proposed by witness Garrett.

H.F. Lee and Cape Fear Beneficiation Projects

In the last of three prudence-related disallowances proposed by Public Staff witnesses Garrett and Moore, witness Moore recommends a disallowance of $130,384,392, which represents a portion of the costs incurred by subcontractor Zachry Industrial Inc. (Zachry) for Engineering, Procurement, and Construction (EPC) expenses at the H.F. Lee and Cape Fear beneficiation sites. (Tr. vol. 15, 1183.) The crux of witness Moore's argument is that, in his view, Duke Energy should not have contracted with Zachry to perform the EPC construction work at H.F. Lee and Cape Fear because its bid for the work was more than twice the cost estimate included in the RFI submitted by The SEFA Group, Inc. (SEFA) which contemplated that H&M Company, Inc. (H&M) would construct the beneficiation units. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** The Commission rejects witness Moore's proposed disallowance for several reasons.

First, the Commission finds that it is not reasonable for witness Moore to compare the construction estimate included in SEFA's RFI response to those included in Zachry's EPC contract as the SEFA/H&M estimate was prepared before the Company knew the final project scope. As Company witness Bednarcik explains, the purpose of the RFI was to collect general written information about capabilities of various contractors in an effort to screen contractors and help the Company make a decision on what steps to take next. (Tr. vol. 17, 118.) The RFI helps the contractor consider its strategy for potentially submitting a formal proposal. However, it is clearly intended to be less rigorous than a request for proposal which would requires a firm commitment. In this instance, the RFI promulgated by the Company in August of 2016 for the H.F. Lee and Cape Fear beneficiation projects did not ask responding contractors for any site-specific estimate of the EPC costs to be incurred for the beneficiation sites, nor did it provide project details that would be necessary to calculate such an estimate – in large part because the Company was still developing the project's precise scope and determining the locations for beneficiation. (Id.) As such, the RFI was nothing more than an invitation to identify entities capable of undertaking the project, and respondents to the RFI provided data points readily available to help the Company assess its capabilities. The estimate included in SEFA's RFI was based on the costs it incurred, through H&M, to construct the Winyah STAR Facility in South Carolina. H&M was not the entity responding to the RFI, it was SEFA. SEFA had previously partnered with H&M to construct Winyah STAR Facility. As witness Moore appeared to agree, the use of the Winyah STAR facility by SEFA in its RFI response was just an "example." Witness Moore did *not* believe that the Company's beneficiation unit was intended to be an "identical-type facility [such that the Winyah STAR Facility] should be used as the basis." Instead, per witness Moore, the Winyah STAR Facility should only "give[ ] the people that build it an idea of what it will take to build a similar facility that meets CAMA requirements."[65] (Tr. vol. 15, 1317.)

However, the devil is in the details when comparing projects, and the ultimate detail witness Moore overlooked is the CAMA requirements. As witness Bednarcik points out, there are several key differences between Winyah and the Company's H.F. Lee and Cape Fear projects that impact cost. Most importantly, the Winyah plant is designed to produce 250,000 tons of ash product per year, while the H.F. Lee and Cape Fear beneficiation units *must* produce 300,000 tons of ash product per year to meet CAMA requirements. (Tr. vol. 17, 122; Garrett/Moore Cross Examination Ex. 3 (Fedorka Aff.).) CAMA's output requirement necessitated installation of a second external heat exchanger at H.F. Lee and Cape Fear along with all associated equipment. Witness Moore did not perform any analysis as to the impact of costs of going from 250,000 tons of ash to 300,000 tons. (Tr. vol. 15, 1321.) Importantly, the Duke units must be designed to ensure this output to comply with CAMA a point that witness Moore appears to discount without any analysis to support his view. (Id. at 1323.) The Commission is persuaded and affords significant weight to witness Bednarcik's testimony that the onus to ensure the Company's beneficiation unit meets the output requirements of CAMA *at all times* works a significant additional challenge with which the Winyah facility does not have to contend. (Tr. vol. 17, 122-23.)

Aside from the output challenges imposed by CAMA, the record reflects additional structural differences between the two facilities that impact cost. For example, Winyah typically uses 67% ponded ash and 33% production ash. (Id. at 122.) Ash at the Company's plants, on the other hand, is 100% ponded ash and required the addition of a grinding circuit to meet ASTM standards for concrete. (Garrett/Moore Cross Examination Ex. 3 (Fedorka Aff.).) The two facilities also use different scrubbers, and the dry scrubbers

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65 Witness Moore gave live testimony regarding construction of Duke Energy's beneficiation units in the DEC-specific hearings, and his articulation of the Public Staff's position in that hearing is made part of the DEP Record through the Amended Stipulation.

at H.F. Lee and Cape Fear required a second bag house with additional induced draft fans. (Tr. vol. 17, 122.) Finally, the Winyah STAR facility was a refurbishment/addition to an existing carbon burn-out facility and SEFA was able to reuse a significant part of the carbon burn-out facility when constructing Winyah's STAR unit. Conversely, the Company's facilities are new construction. (Id.) For all of these reasons, the Commission agrees with the Company that the construction cost estimate included in SEFA's RFI is not a reliable marker for evaluating the reasonableness and prudency of the costs to construct the H.F. Lee and Cape Fear beneficiation units, and, in any event, witness Moore cannot offer any conclusive evidence that H&M could have completed the project at the cost quoted in SEFA's RFI.

Indeed, through the RFI response by SEFA, it is clear that the amounts quoted by SEFA were not firm, and instead only offered a data point of the cost of the Winyah STAR facility. As witness Moore admitted on cross-examination, SEFA was clear that pricing "would be finally determined following identification of each location and the development of comprehensive plans and specifications for such Duke Star facilities. (Tr. vol. 15, 1332.) Although SEFA moved forward in the process of developing the beneficiation facilities, H&M did not. (Tr. vol. 17, 121.) There is no evidence in this record for what pricing H&M would have offered for CAMA designed site-specific beneficiation facilities. What is clear from the evidence presented is that DEP had an obligation to comply with CAMA's requirements including the development of three beneficiation facilities, and that the Company utilized a competitive solicitation to identify qualified contractors able and willing to undertake the work required by CAMA.

The Commission likewise is not persuaded by witness Moore's contention that the Company should have solicited additional bids for the work and/or contracted with multiple EPC contractors to build the beneficiation units. After H&M declined the project, in January 2017, the Company sent out an RFP for the balance of plant engineering and construction to four Companies – CBI, Fluor, Kiewit, and Zachry. Each of these companies were engaged in current EPC contracts with the Company and/or had successfully worked with the Company in the past. (Tr. vol. 17, 125.) Witness Moore fails to articulate any reason why it was not reasonable and prudent for the Company to target and solicit bids from these four contractors with proven success, nor does he affirmatively identify any other contractor with whom the Company should have contracted. The Company held a comprehensive RFP and Zachary scored the highest and was selected. In any event, H&M removed itself from contention despite the Company's interest in pursuing the relationship. (Id.)

Witness Moore's alternative suggestion that the Company should have engaged three separate EPC subcontractors is likewise specious. As witness Bednarcik notes, witness Moore did not even consider whether SEFA had the capacity to support three separate contractors. Perhaps most importantly, witness Moore's proposal ignores economies of scale the Company was able to realize by executing a single contract, using a single engineering facility design for all three beneficiation sites. (Id. at 126.) Indeed, as acknowledged by witness Moore, SEFA's own RFI response gave significant weight to the cost saving from the economies of scale achieved by combining the projects, noting the "significant cost savings available from bundling of purchasing for all three facilities and the economies of scale in stating design, construction, and startup activities[.]" (Tr. vol. 15, 1344-45.) Moreover, it is pure speculation that H&M would have been able to construct a singular plant at a hypothetical cost in the absence of a concrete bid from H&M. (Tr. vol. 17, 273.) As witness Bednarcik noted on cross-examination, the concerns that H&M may have had with "scope" that appear to be the basis of questions from Public Staff are not as easily defined by the number of projects.[66] Instead, H&M's primary concerns were related to the Company's mandatory project controls and oversight which are all standard in Duke's large construction projects whether it be one project or a combination of projects. (Id. at 273-74.) What is clear is that witness Moore was unable to provide any credible support for his argument. In short, witness Moore's proposal amounts to nothing more than unsupported hypotheticals that are insufficient evidence upon which to impose a disallowance.

Witness Moore's remaining arguments in favor of disallowance are equally unconvincing. His suggestion that the Company should have sought statutory relief from CAMA's beneficiation requirements is not a real-world solution. First, putting aside the assumption that witness Moore is making without support that the amendments to CAMA that included the requirement for beneficiation were not well understood when passed by the legislature, there is no guarantee that the General Assembly would have actually granted such relief. The General Assembly was very specific regarding the type of beneficiation projects it intended to have constructed and the timetable for their operation. There is no mention of cost within the statute, nor is there any evidence to suggest that Duke Energy's cost incurred for compliance with the beneficiation requirement is outside the range of what was contemplated by the General Assembly. Indeed, the cost incurred by Duke Energy reflects the cost necessary to meet the very specific requirements of the statute. If the General Assembly had premised the statute upon a level of cost lower than what the Company has incurred to comply, the statute would have reflected that, but it does not. Even under witness Moore's alternative world analysis, had the General Assembly taken action, it is almost a certainty that the original CAMA deadline would have passed before such a bill could be drafted, vetted, and passed.

Likewise, witness Moore's suggestion that the Company should have sought guidance from DEQ upon learning of Zachry's estimated EPC costs is also misguided. DEQ is responsible for enforcing the State's environmental laws irrespective of an entity's cost of compliance. There are no cost considerations in the beneficiation provisions of CAMA and it would therefore be inappropriate for DEQ to make such considerations as part of its enforcement.

In sum, the Commission finds the evidence put forth by witness Moore in support of his proposed disallowance to be severely lacking and accordingly it rejects the disallowance.

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[66] Witness Bednarcik gave live testimony regarding construction of Duke Energy's beneficiation plants in the DEC-specific hearing, and her articulation of the Company's position in that hearing is made part of the DEP Record through the Amended Stipulation.

Conclusion

DEP has shown by the greater weight of the evidence that its coal ash basin closure costs actually incurred over the period from September 1, 2017, through February 29, 2020 are (a) known and measurable, (b) reasonable and prudent, and (c) capital in nature and used and useful, and, as such, those costs are recoverable in rates. Those costs were deferred by prior order of the Commission, and the Company is entitled to full recovery of its financing costs, at its weighted average cost of capital authorized in this case, upon those deferred costs, through August 2020. Furthermore, recovery of these costs, both actual and financing, shall occur over a five year amortization period, and for all of the reasons already articulated, the Company is entitled to full recovery of its financing costs, at its weighted average cost of capital authorized in this case, during that amortization period.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 76

The evidence supporting these findings and conclusions is contained in the Company's verified Application and Form E-1; the evidence, orders and other matters of record in Docket No. E-7, Sub 1146 and Docket No. E-2, Sub 1142, late-filed exhibits, motions and Commission orders in this docket, and the testimony and exhibits of the following expert witnesses: DEP witness Smith; Public Staff witness Maness, and the entire record in this proceeding.

The Company has requested that the Commission issue an accounting order authorizing the continued deferral of CCR compliance costs incurred after the February 29, 2020 cut-off in the current case. Specifically, the Company asks that the Commission allow it to continue deferring CCR compliance spend related to ash basin closure beginning after February 29, 2020, the depreciation and return on CCR compliance investments related to continued plant operations placed in service after March 1, 2020, and a return on both deferred balances at the overall rate of return approved in this case.

Public Staff witness Maness contends that deferral of future capital costs related to non-ARO compliance projects should be restricted to ARO-qualifying costs. (Tr. vol. 15, 1585-86.) Witness Maness states that Public Staff was surprised at the number and magnitude of the non-ARO related projects that DEP proposes for deferral. Witness Maness testified that until DEP made its current rate application, the Public Staff thought that the capital costs mentioned in the Company's previous deferral request[67] would be ARO-related, not related instead to projects associated with the continuing operation of the generating plants. (Id. at 1585.)

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[67] *See Duke Energy Progress, LLC and Duke Energy Carolinas, LLC's Petition for an Accounting Order*, Docket Nos. E-2, Sub 1103 and E-7, Sub 1110, (December 30, 2016) (Deferral Petition). The Company's deferral request in Docket No. E-2, Sub 1103 was consolidated with DEP's prior rate case and dealt with in the 2018 DEP Rate Order.

The Company, through witness Smith, points out that the Deferral Petition "clearly articulated" the nature of the Company's deferral request, to include "the deferral of all non-capital costs as well as the depreciation expense and cost of capital at the weighted average cost of capital for all capital costs related to activities required under the legislative and regulatory mandates" outlined in the Deferral Petition. (Tr. vol. 13, 210.) Witness Smith also fundamentally disagrees with witness Maness' interpretation of the deferral approved in the 2018 DEP Rate Order, and noted that the current deferral request mirrors the deferral framework approved by the Commission in the 2018 DEP Rate Order. (Id. at 210-11.) In the 2018 DEP Order, the Commission noted in Finding of Fact No. 51 that: "DEP expects to incur substantial costs related to CCRs in future years. It is just and reasonable to allow deferral of these costs, with a return at the overall cost of capital approved in this Order during the deferral period. Ratemaking treatment of such costs will be addressed in future rate cases." (Id. at 210.) The Company maintains that its prior deferral request included ARO and non-ARO compliance costs and the Commission approved the deferral petition. (Id. at 211.) Accordingly, DEP believes that the Commission should not reverse its previous authorization to defer these costs as recommended by witness Maness.

Based on the evidence presented in this proceeding, the Commission finds that the Company's request to continue deferring CCR basin closure costs, including ARO and non-ARO compliance-related costs, is just and reasonable, and fair to all parties. The Commission finds no persuasive reason to reverse the deferral framework approved in the 2018 DEP Rate Order. With respect to deferral generally, no party disputes the need for a deferral to capture future costs and deferral was approved in the 2018 Rate Order as well as the 2018 DEC Rate Order. The Public Staff specifically disagrees with DEP regarding future deferral of non-ARO CCR compliance costs and believes that such deferral should be restricted to ARO-qualifying costs. However, as DEP points out, this Commission's prior authorization did not distinguish ARO-CCR compliance costs from non-ARO-CCR compliance costs. And, this Commission found no persuasive evidence in the record supporting a reversal of its previous authorization to defer these costs.

Therefore, the Commission grants the requested permission to continue deferring the CCR-related costs described throughout this section. The Company shall be permitted to defer all CCR compliance costs incurred after February 29, 2020 with a return at the overall cost of capital approved in this Order during the deferral period.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 77-78

The evidence supporting these findings and conclusions is contained in the Public Staff Partial Stipulations, the Customer Group Stipulations, NCSEA and NCJC et al. Stipulation, Vote Solar Stipulation, DEP's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

After giving effect to the approved Public Staff Partial Stipulations, the Customer Group Stipulations, the NCSEA and NCJC et al. Stipulation, the Vote Solar Stipulation, and the Commission's decision on the Unresolved Issues, the Commission approves the Company's proposed revenue increase of $408,933,000, to incorporate the Company's adjustments filed in its Second Settlement Testimony and Exhibits filing and the Company's Second Supplemental Testimony and Exhibits filing, to be further adjusted by the Public Staff's recommended adjustments to the May 2020 Updates described in Public Staff witness Maness's Supplemental Testimony Supporting the Second Partial Settlement and Exhibits filed on September 16, 2020, and which the Company accepts.[68] In addition, the Commission also approves the Company's request to offset the revenue requirement, as adjusted, by a rate increase of $7,381,000 for the Revised Annual EDIT Rider 1 and reduction of ($152,348,000) for the Annual EDIT Rider 2 to refund certain tax benefits,[69] ($2,091,000) for the Regulatory Asset and Liability Rider, for a net revenue increase of $261,875,000, as adjusted.[70]. The approved revenue increase is based on the following amounts of test year pro forma operating revenues, operating revenue deductions, and original cost rate base (under present rates), which are to be used as the basis for setting rates in this proceeding: $3,763,735,000 of operating revenues, $3,011,759,000 of operating revenue deductions, and $10,845,429,000 of original cost rate base.

Pursuant to N.C.G.S. § 62-133(a), the Commission is required to set rates that are "fair both to the public utilities and to the consumer." In order to strike this balance between the utility and its customers, the Commission must consider, among other factors, (1) the utility's reasonable and prudent cost of property used and useful in providing adequate, safe, and reliable service to ratepayers, and (2) a rate of return on the utility's rate base that is both fair to ratepayers and provides an opportunity for the utility through sound management to attract sufficient capital to maintain its financial strength. *See* N.C.G.S. § 62-133(b). DEP's continued operation as a safe, adequate, and reliable source of electric service for its customers is vitally important to the Company's individual customers, as well as to the communities and businesses served by the Company. DEP presented credible and substantial evidence of its need for increased capital investment to, among other things, maintain and increase the reliability of its system and comply with environmental requirements.

Based on all of the evidence, the Commission finds and concludes that the revenue requirement, rate design, and the rates that will result from this Order strike the appropriate balance between the interests of DEP's customers in receiving safe, reliable, and efficient electric service at the lowest possible rates, and the interests of DEP in maintaining the Company's financial strength at a level that enables the Company to

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[68] The Company's revenue requirement will be revised to incorporate the impact of the Public Staff's May 2020 Updates adjustments, as discussed further herein, when the Company makes its compliance filing in accordance with this Order.

[69] Note that the Annual EDIT Rider 2 Year 1 flowback estimate of ($152,348,000) is based on an estimate of the amount to be flowed back to customers through the Company's interim rates and is subject to change based on the actual amount flowed back when the revised rates approved in this Order go into effect.

[70] As adjusted per the Public Staff's May 2020 Updates audit recommendations, which the Company accepts.

attract sufficient capital. As a result, the Commission concludes that the revenue requirement and the rates that will result from that revenue requirement established as a result of this Order are just and reasonable under the requirements of N.C.G.S. § 62-30, *et seq*.

IT IS, THEREFORE, ORDERED as follows:

28. That the Harris Teeter Stipulation filed by DEP is approved in its entirety;

29. That the Commercial Group Stipulation filed by DEP is approved in its entirety;

30. That the SGS-TOU rate schedule shall be modified in accordance with the Harris Teeter Stipulation and Commercial Group Stipulation;

31. That the CIGFUR Stipulation filed by DEP is approved in its entirety;

32. That unprotected EDIT and deferred revenue should be refunded to customers on a uniform cents per kWh basis as provided in the CIGFUR Stipulation and reflected in Pirro Second Settlement Ex. 8;

33. That the NCSEA and NCJC et al. Stipulation filed by DEP is approved in its entirety;

34. That the Vote Solar Stipulation filed by DEP is approved in its entirety;

35. That DEP shall recover the deferred actual coal ash basin closure costs it has incurred during the period from September 1, 2017 through February 29, 2020, along with financing costs through August 2020, for a combined total amount of $440.1 million. These costs shall be amortized over a five-year period, with a return on the unamortized balance at DEP's weighted average cost of capital authorized in this case;

36. DEP's request to continue the deferral for environmental CCR compliance costs incurred beginning March 1, 2020, including the depreciation and return on CCR compliance investments related to continued plant operations placed in service after February 29, 2020, and a return on both deferred balances at the overall rate of return approved in this case, shall be, and is hereby approved;

37. That DEP shall recalculate and file the annual revenue requirement with the Commission within 10 days of the issuance of this Order, consistent with the findings and conclusions of this Order and the Public Staff Partial Stipulations. The Company shall work with the Public Staff to verify the accuracy of the filing. DEP shall file schedules summarizing the gross revenue and the rate of return that the Company should have the opportunity to achieve based on the Commission's findings and determination in this proceeding;

38. That DEP is hereby authorized to adjust its rates and charges in accordance with the Public Staff Partial Stipulations and findings in this Order effective for service

rendered on and after the following day after the Commission issues an Order accepting the calculations required by Ordering Paragraph No. 37;

39. That the Commission shall issue an Order approving the final revenue requirement numbers once received from DEP and verified by the Public Staff as soon as practicable;

40. That the depreciation rates proposed by DEP in this case are approved;

41. That within 30 days of this Order, but no later than ten business days prior to the effective date of the new rates, DEP shall file for Commission approval five copies of all rate schedules designed to comply with this Order, accompanied by calculations showing the revenues that will be produced by the rates for each schedule; and

42. That DEP shall submit a proposed customer notice to the Commission for review and approval, and upon approval of the notice by the Commission, shall give appropriate notice of the approved rate increase by mailing the notice to each of its North Carolina retail customers during the billing cycle following the effective date of the new rates.

ISSUED BY ORDER OF THE COMMISSION.

This the ______ day of______________, 2020.

NORTH CAROLINA UTILITIES COMMISSION

Kimberley A. Campbell, Chief Clerk

CERTIFICATE OF SERVICE

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

I hereby certify that a copy of the foregoing **DUKE ENERGY PROGRESS, LLC FINDINGS OF FACT AND EVIDENCE AND CONCLUSIONS FOR PROPOSED ORDER REGARDING CONTESTED ISSUES UNRESOLVED BY THE PUBLIC STAFF PARTIAL STIPULATIONS** was served electronically or by depositing a copy in United States Mail, first class postage prepaid, properly addressed to the parties of record.

This the 4th day of December ,2020.

/s/ Camal O. Robinson
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