STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

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

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1193 In the Matter of Application of Duke Energy Progress, LLC, for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego DOCKET No. E-2, SUB 1219 In the Matter of Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	BRIEF OF THE ATTORNEY GENERAL'S OFFICE

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The North Carolina Attorney General's Office (AGO) respectfully submits this Brief in opposition to the application for a general rate increase filed by Duke Energy Progress, LLC (DEP or Duke or the Company) in the above captioned docket.

INTRODUCTION

DEP bears the burden of proof to show that its proposed rate increase is both just and reasonable,[1] and DEP has failed to meet that burden. In this Brief, the AGO focuses on four key problems with DEP's proposed rate increase.

[1] N.C. Gen. Stat. §§ 62-75; 62-134(c).

First, it is unjust and unreasonable for DEP, as it proposes, to recover its expenditures for closure of coal ash impoundments and disposal of Coal Combustion Residuals (coal ash or CCR) in North Carolina retail rates.

Granting recovery of these expenditures would allow DEP to charge ratepayers for costs to close facilities despite extensive evidence that the facilities were imprudently operated for many years. It is DEP's burden to establish the prudence of costs in light of the evidence. Because DEP has not carried this burden, DEP's proposal to recover these expenditures should be denied. Even if this burden were placed on the parties that challenge DEP's costs, the AGO and Public Staff have proven several hundred million dollars of specific cost disallowances. *See infra* § I.C., p 58.

Moreover, it is appropriate for the Commission to continue monitoring the outcome of Duke's litigation seeking insurance coverage for coal ash costs. *See infra* § I.D, p 67.

In addition, DEP's proposed increase not only includes the costs of closing coal ash ponds, but *also* adds a rate of return to those costs as they are deferred and again as they are amortized. Assuming *arguendo* that DEP has demonstrated that it is just and reasonable to pass along some or all of the costs to future ratepayers, it is not appropriate or lawful for the Commission to authorize DEP to add a rate of return on the costs during deferral and amortization. *See infra* § I.E, p 68.

Further, because these are costs attributable to past service, DEP's request to recover the costs from current and future customers is based on a question of what is fair both to DEP's investors and to customers. The Commission should take into account the extensive evidence that DEP underestimated coal ash costs in past proceedings because it pushed off tasks and put off costs for generations. DEP's inaction makes it unfair to charge current ratepayers for those costs now. *See infra* § I.F, p 83.

Second, the 9.6% rate of return on equity and 52% equity capital structure proposed in the non-unanimous Stipulations[2] entered by DEP and some parties would fix a return that is significantly higher than necessary to attract investors. The rate of return factors exceed the return required by current market data. They would unnecessarily add more than $48 million each year as compared to the revenue requirement for an ROE of 9.0% and a 51.5% equity capital structure, and there is ample evidence to support the sufficiency of the lower ROE and smaller equity ratio of equity. Keeping more than $48 million in local communities annually will better serve ratepayers. *See infra* § II, p 96.

Third, DEP should promptly return to ratepayers over $400 million dollars that has accumulated in excess deferred taxes and tax-related deferred revenues. DEP concedes that the benefit of these tax cuts should go to ratepayers, and has begun returning the money to customers as a full offset to the temporary rate increase that began in September. But instead of continuing to offset a rate increase, DEP proposes a slow, phased return of these funds to ratepayers once

[2] DEP filed two partial stipulation agreements with the Public Staff – North Carolina Utilities Commission and filed partial stipulation agreements with other parties that settled among those parties a number of matters, including the capital structure and rate of return on common equity that DEP should be allowed an opportunity to earn. (*See* 31 July 2020 DEP-Public Staff Stipulation at 10).

new rates take effect. Ratepayers have already waited for years to receive the benefit from these tax cuts, and DEP suggests no logic that makes it reasonable for ratepayers to wait any longer, particularly during a time when many of them are struggling economically from the effects of the COVID pandemic. The Commission should require a full offset to rates or – better yet – a reduction to reflect a return of the excess tax reserves as soon as possible, and in no more than two years. *See infra* § III, p 118-19.

Fourth, DEP has unreasonably limited the technologies and opportunities available to its customers for use in connection with the installation of smart meters and Customer Connect, by refusing to use Green Button Connect or a similar technology and by relying instead on a nonstandard and outdated approach. In the last general rate case for DEP's affiliate Duke Energy Carolinas, the investment in AMI meters was questioned due to limited advantages that were available to customers. DEP has proceeded with widespread installation of AMI meters although the advantages have not yet materialized for either Duke Carolinas customers or for DEP customers. If DEP is allowed to receive full recovery of DEP's investment in AMI, it should be directed to file plans that promptly incorporate Green Button Connect or another similarly advanced standard technology. These superior technologies should be included in the implementation of Customer Connect without delay. *See infra* § IV, p 124.

ARGUMENT

I. DEP'S COAL ASH COSTS SHOULD NOT BE RECOVERED IN RATES.

A. DEP Has Not Shown that It Incurred Its Coal Ash Costs Reasonably.

1. The standard for cost recovery gives DEP the burden to prove costs were reasonably incurred and establishes that costs are not reasonable when they stem from a violation of environmental laws.

Under the ratemaking statute, utilities have the burden to show that their costs were reasonably incurred. N.C. Gen. Stat. §§ 62-75, 62-134(c). The costs "are presumed reasonable unless challenged." *State ex rel. Utils. Comm'n v. Conservation Council*, 312 N.C. 59, 64, 320 S.E.2d 679, 683 (1984). To make a utility satisfy its burden, challengers must offer "affirmative evidence . . . that challenges the reasonableness of [the utility's] expenses." *State ex rel. Utils. Comm'n v. Intervenor Residents* (*Bent Creek)*, 305 N.C. 62, 76, 286 S.E.2d 770, 779 (1982). Once the challengers make this showing, the utility must prove that its costs were reasonably incurred. *Id.* Utility expenses that result from imprudent management are unreasonable. *See State ex rel. Utils. Comm'n v. N.C. Power*, 338 N.C. 412, 421, 450 S.E.2d 896, 901 (1994).

A utility's costs are not reasonably incurred when they stem from a utility's violation of environmental laws. *State ex rel. Utils. Comm'n v. Pub. Staff, N.C. Utils. Comm'n* (*Glendale Water*), 317 N.C. 26, 40-41, 343 S.E.2d 898, 907-08 (1986).

2. The history of DEP's coal ash management demonstrates that DEP took no Action, despite having knowledge of the risks created by its coal ash disposal practices.

a. Background

DEP has eight (8) coal-fired power plants; seven in North Carolina and one in South Carolina. Power plants generating electricity through the combustion of coal necessarily create waste products. "Coal combustion residuals" include fly ash, bottom ash, boiler slag, mill rejects, and flue gas desulfurization residue, all requiring disposal through proper management. N.C. Gen. Stat. § 130A-290 (a)(2b). "Coal ash" consists primarily of what is termed fly ash and bottom ash. Fly ash is a fine ash recovered before it is discharged to the atmosphere, while particles that do not escape as fly ash fall to the bottom of the furnace and primarily become bottom ash. (DEP Tr. vol. 13, 573) Fly ash generally tends to have much higher concentrations of metals in it than bottom ash. (DEP Tr. vol. 13, 816) Due to this tendency, dry fly ash handling has become an effective alternative method of coal ash disposal.

Coal ash, although not treated as a hazardous waste, contains heavy metals and potentially hazardous constituents, such as arsenic, barium, boron, cadmium, chromium, iron, lead, manganese, mercury, nitrates, sulfates, selenium, thallium, total dissolved solids, and vanadium. (DeMay AGO Direct Cross Exhibit 1 at 10, para 40; DEP Tr. vol. 13, 574). After combustion, most of these organic components of the coal ash are burned off, leaving the remaining ash with a higher concentration of these metals, making them more toxic. (DEP Tr. vol. 13, 574) If toxic compounds such as metals are released to the environment and are present in sufficiently high concentrations, they can pose risks to human health as well as ecological receptors. (Id.) For example, boron found in United States coal, measured at concentrations in the range of 1 to 350 milligram per kilogram before combustion, increases to the range of approximately 30 to 6,500 milligrams per kilogram when it burns off and becomes part of the coal ash. (Id. at 583)

As the coal ash accumulates after combustion, it must be removed and its disposal managed. Historically, DEP employed unlined basins to store the coal ash generated by its power plants. (DeMay AGO Direct Cross Exhibit 1 at 10, para 41) The plants would mix coal ash with water to form a slurry, which was then carried through sluice pipe lines to the unlined basins. (DEP Tr. Vol. 13, 573) In these basins, the coal ash separates from the slurry and settles at the bottom of the basins, while less-contaminated water rises to the surface. (Id.) Some metals present in the coal ash leach out of the accumulated wet ash in the basins and migrate downward into the underlying soil due to the pressure of the hydraulic head maintained in the basin. (Id. at 584) The higher the concentration of a metal, the better the chance it is to move through soil and groundwater. (Id. at 575) As the capacity of the soil to retain metals below and downgradient of the basin is reduced over time, the groundwater becomes more impacted over time. (Id.) Once a metal becomes soluble and mobile in groundwater, the metal can migrate with groundwater downgradient and potentially impact groundwater receptors such as drinking water supply wells and surface waters such as streams and lakes. (Id. at 577)

In addition, all of DEP's facilities have disposed of numerous other liquid wastes to their ash ponds, including but not limited to flue gas wastewater from metal cleaning, boiler blowdown, floor drains, tank and drum rinse waters, sumps, landfill leachate, and sandblast material. (Id. at 579) When other liquid wastes are discharged to an ash pond, they may lead to lower pH of water in the basin and increased leaching of metals from metal-bearing wastes in the basin. (Id.) Ultimately, all of DEP's coal-fired power plant facilities have experienced coal ash leachate problems, resulting in decades of groundwater contamination that has continued to the present and will continue into the future. (DeMay AGO Direct Cross Exhibit 1; DEP Bednarcik AGO Direct Cross Exhibit 18; DEP Bednarcik Rebuttal AGO Cross Exhibit 2)

b. Industrial and governmental knowledge

In the late 1970s and 1980s, a growing consensus emerged among government and industry officials that storing coal ash in unlined ash basins resulted in groundwater contamination. (Hart Exhibits 18-21; DEP Tr. vol. 13, 588; Junis Exhibits 7-8)

North Carolina not only recognized the significant impact of this contamination of groundwater, but implemented laws to protect the land and the surface and groundwaters of the State. In 1979, the North Carolina General Assembly and the Environmental Management Commission noted that changes in land use, including more industrial activities such as the construction of coal-fired power plants, were creating more potentially hazardous wastes being disposed on the land without the benefit of a careful consideration of the proper management of the disposal of the wastes to avoid groundwater contamination. (Hart Exhibit 10) North Carolina took action by promulgating the 2L groundwater rules in order to maintain and preserve the quality of the State's groundwaters and to prevent and abate groundwater contamination. (*Id*.) The 2L groundwater rules were designed to impose strict liability on any person whose activities cause the concentration of any substance in groundwater to exceed the limits of that substance's specific 2L groundwater standards. 15A N.C. Admin. Code 02L .0103(d) (2018).[3]

Evidence shows that in 1978, 1979, and 1980, power industry observers and participants were aware that the disposal of coal combustion residuals presented a significant problem. In 1978, the EPA published a draft report regarding the management and disposal of solid wastes from the electric utility industry, finding that the leaching of compounds from fly ash, bottom ash, and Flue-gas Desulfurization (FGD) scrubber sludge have the potential for groundwater or surface water contamination. (Hart Exhibit 18) In 1979, the Los Alamos Scientific Laboratory prepared a report specific to the coal and utilities industry, advising that groundwater contamination from coal combustion residuals from coal ash ponds was an environmental problem of great significance. (Junis Exhibit 7; DEP Tr. vol. 19, 556) Later that year, the EPA, in conjunction with the US Army Corps of Engineers, published a study evaluating the effects of the disposal of flue gas cleaning wastes in pits and ponds at three field sites, all of which resulted in sludge and ash-derived compounds migrating out of the area of the pond and degrading the quality of groundwater. (Hart Exhibit 19) The

[3] DEP witness Williams opined that groundwater contamination occurs when there is an "exposure to receptors that come into contact with that groundwater." In response to this definition, AGO expert witness Hart testified that "I think it shows Ms. Williams' unfamiliarity with the North Carolina groundwater standards and rules." (DEP Vol 13, 861-62) As Hart explains, the 2L groundwater rules are not receptor-based as noted above, but require action when it is determined that a 2L groundwater standard is exceeded, including an assessment as to the exceedance's cause and significance. (Id.) *See fn 7* for a summary of AGO expert witness Hart's qualifications.

Tennessee Valley Authority, in 1980, echoed these concerns, as well as identifying the leaching of coal ash metals as another significant concern. (Hart Exhibit 20)

These concerns continued to grow nationwide, and in 1988, the EPA conducted a study to evaluate the potential adverse effects on human health and the environment from the disposal of wastes from coal combustion. (Joint Exhibit 13; Hart Exhibit 21) The EPA forwarded this study in a report to Congress. (*Id.*) This report stated that the industry was: 1) not only aware of the groundwater contamination issues stemming from the leachate from coal ash ponds, but 2) discussing alternative disposal methods, including the demonstrated value of installing liners in the ponds. (*Id.*) Further, in the 1988 report, the EPA promoted the necessity for groundwater monitoring, recommending that wells be located both downgradient of potential source areas, as well as upgradient to determine background concentrations for comparison of naturally occurring metals. (*Id.*)

A 1991 report made clear that the coal ash disposal risks being discussed nationwide posed a significant problem in DEP's region of North Carolina. (Hart Exhibit 15) The Electric Power Research Institute (EPRI) conducted a study at an approximate 40-acre basin at an electric generating plant in the Piedmont Region of the Southeastern United States. (*Id*.) EPRI found that there was an estimated discharge from the base of the basin of between 200 million to 450 million gallons per year to the underlying soil. (*Id.*) This study is especially relevant because the DEP Asheville, Cape Fear, Mayo, and Roxboro facilities located in the Piedmont and Blue Ridge Regions have similar geology as that described in the study. (DEP Tr. vol. 13, 584). The remainder of the DEP facilities are located in the Coastal

Plain Region which would tend to have even higher infiltration rates because of the typically more transmissive (*i.e.*, sandier) nature of the subsurface in that region. (Id.)

Because all of DEP's coal ash basins are within 5 feet of the uppermost aquifer or in wetlands, they are especially susceptible to groundwater contamination issues. (Hart Exhibits 51-58) In accordance with the 2L groundwater rules, the compliance boundary does not apply to bedrock contamination, and any contamination within the bedrock would need to be remediated. (DEP Tr. vol. 13, 561) The 1991 EPRI study warned that as more leachate enters the groundwater system, it can lead to higher groundwater concentrations and further migration distances in groundwater over time. (Hart Exhibit 15) Although DEP was thereby warned that contaminant concentrations would increase as more leachate entered the groundwater system, it did not take action to change its coal ash disposal practices.

c. DEP's knowledge of groundwater contamination and lack of response from the 1980s up to its merger with Duke Energy in 2012.

Despite these known risks and industry trends, DEP continued to place ash in unlined basins throughout the 1980s and over the decades that followed. DEP did so even though it knew that its ash basins were contaminating groundwater, and then DEP exacerbated the problem by ignoring groundwater contamination when it was detected, unless the issue was impossible to hide or DEP was directly required to remediate the contamination by DEQ.

In the 1970s and 1980s, DEP's Roxboro facility affected fish reproduction through the discharge of high concentrations of selenium from its coal ash basins, causing a decline in fish populations in Hyco Lake and resulting in economic damages of $877 million. (DEP Tr. vol. 13, 557) As a result, North Carolina issued a fish consumption advisory for Hyco Lake in 1988. (Id.) In response to this advisory, DEP eventually installed a dry ash handling system to meet new permit limits for selenium in 1990. (Id.) Due to the accumulated environmental damages, the State did not issue a rescission of the fish advisory until 2001. (Id.)

Further, groundwater monitoring initiated at Robinson, Roxboro and Weatherspoon as early as the mid-1990s to early 2000s confirmed that DEP had groundwater contamination issues with coal ash disposal areas at those coal-fired plants. (DEP Tr. vol. 13, 537) Despite these established groundwater contamination issues, DEP did not perform any additional monitoring to determine the extent of groundwater impacts or whether the facilities were in compliance with the law at the compliance boundary. (Id. at 690)

Instead of taking action to identify the extent of contamination and monitor the sites, in 1996, DEP notified its insurers. In the notification, DEP warned its insurers that it could face liability for violating North Carolina’s 2L rules that prohibit groundwater contamination. (DEP Tr. vol. 13, 606) DEP reported that its coal ash basins had contaminated the groundwater at all of the coal-fired plants above the 2L groundwater cleanup criteria at the locations where DEP had actually tested the groundwater: the Cape Fear, H.F. Lee, Robinson, Roxboro, Sutton and Weatherspoon plants. (Id. at 607)

Once DEP discovered these actual or threatened violations of the 2L groundwater rules, the Rules required DEP to stop its basins from contaminating groundwater. Under the 2L groundwater rules, polluters that cause an exceedance of the 2L standards must, among other things, abate, contain, or control the migration of the contaminants. 15A N.C. Admin. Code 2L.0106. Any necessary corrective action, dependent on the level of contamination, would include the elimination of the contamination source by the removal, treatment or control of the primary pollution source. 15A N.C. Admin. Code 2L.0106(c)(2), (f)(3) (2015).

However, DEP has not shown that, after it learned of these exceedances of the 2L groundwater rules (or were at least at serious risk of doing so as early as 1996), it took any action to control the groundwater exceedances or eliminate the source of the contamination unless forced to do so. Despite the 1978 EPA report, the 1979 Los Alamos report, the 1979 EPA/US Army Corps of Engineers study, the 1980 EPA/TVA study, the 1988 EPA report, and the 1991 EPRI report specific to the Piedmont Region, all of which showed significant risk from the practices that DEP was using to dispose of coal ash, the record is clear that DEP did nothing at those times to abate, contain, confirm, or control the migration of contaminants to the groundwater. (Hart Exhibits 18-21; Junis Exhibits 7-8)

The record contains more than a dozen examples of DEP becoming aware of the risks posed by its coal ash disposal practices, but taking no action to thoroughly investigate the contamination, control and remediate the contamination, and avoid future costs. This evidence includes, but is not limited to, the following:

- As mentioned above, the power industry was aware of the dangers posed by coal ash disposal practices as far back as 1978, and an EPA report warned that groundwater contamination from coal ash ponds like the ones used by DEP was a problem of great significance. (Hart Exhibit 18)

- In the 1960s through the 1980s, when the coal ash basins at DEP's Asheville, Cape Fear, H.F. Lee, Roxboro, and Sutton plants became functionally full, DEP did not take action to properly close those basins. Instead, DEP simply took those basins out of service or reduced those basins' use. (DEP Tr. vol. 13, 602, 697-98)
- Beginning in the mid to late 1970s, DEQ began to warn DEP of its concerns about groundwater contamination from DEP coal ash disposal. (Hart Exhibit 24B)
- In 1978, DEP's request to construct an ash pond for the Mayo facility within Crutchfield Branch met with resistance from the Army Corps of Engineers because of potential groundwater contamination. (Hart Exhibit 24)
- No later than 1983, DEP was directly aware of the positive value of installing a liner in its ash ponds. (Hart Exhibit 24B)
- In 1983, DEQ's authorization of DEP's request to construct a new ash pond at the Sutton site required that DEP install its first 12-inch clay liner in the pond, as well as install and sample seven monitoring wells at the 1971 Ash Basin. (Hart Exhibit 24B) DEP did not apply these practices at its other plants.

- In 1987, DEQ issued DEP a Notice of Non-Compliance for contravening groundwater standards for total dissolved solids and chlorides at and beyond the compliance boundary at the Sutton plant. (Hart Exhibit 24B)
- In the 1970s and the 1980s, DEP became directly aware of the environmental and ecological consequences of groundwater contamination due to DEP's contamination at Hyco Lake and the resulting fish consumption advisory. As a result, DEP ultimately installed its first dry ash handling system to meet new permit limits for selenium in 1990. (DEP Tr. vol. 13, 557) DEP did not install this sort of system at its other plants.
- In the 1990s, DEQ investigated the Sutton plant as a potential Superfund site and found a number of contaminated drinking wells. (Hart Exhibit 59)
- In 1991, a study identified that environmental risks were present specifically in areas like the geologic region of the Piedmont, where many of DEP's facilities were located. (Hart Exhibit 15)
- In 1996, DEP reported to its insurers that its coal ash basins had contaminated groundwater at six sites. (DEP Tr. vol. 13, 606) Still, DEP did not thoroughly investigate the scope of this contamination.
- In 1999, a third party vendor recommended that DEP convert the Weatherspoon facility to dry ash disposal at a cost of $12,500,000. (DEP Late-Filed Exhibit 19, 257)

In 2000, the same third party vendor modified its recommendations at DEP's request, and recommended vertically extending the dike for the short-term and convert to a dry ash system for the long-term, at a combined cost of $20,865,346. (DEP Late-Filed Exhibit 19, 308) It is unknown whether DEP vertically extended the dike, but DEP did not convert to a dry ash handling system until after CAMA and the CCR Rule were enacted.

- In 2004, many of DEP's coal ash ponds were nearing or at capacity. (DEP Late-Filed Exhibit 19, 81-374)
- In 2004 and 2006, DEP retained third party vendors to assess short and long-term strategies for managing ash at their coal ash ponds and received cost estimates for dry ash handling, as well as other alternative methods of disposal for all of its coal ash facilities. Based on the information available, DEP did not take the actions recommended by the vendors.
- In 2009, DEP acknowledged that all of its coal plants had contaminated groundwater. (Hart Exhibit 28)

Yet it was not until after the Dan River spill in 2014 that DEP took action to change its practices. (DEP Tr. vol. 13, 692) These examples are reflective of DEP's culture of mismanagement. DEP became aware early on that groundwater contamination was a significant concern, and that there were ways to contain it through liners and dry ash handling. When forced to act when its basins were nearing capacity and thus becoming more at risk for groundwater contamination, instead of listening to the advice of third parties as to the best methods to lessen the risk of groundwater contamination, DEP postponed action. Now, it is attempting to recover higher costs when a little foresight acted upon at the time would have saved the environment from the level of groundwater contamination that has prevailed for years and DEP a lot of money now currently being owed.

Over the decades, as coal ash accumulated, staff members at DEP repeatedly acknowledged that the unlined basins at the Company's power plants were contaminating groundwater. DEP staff commissioned reports and obtained information regarding methods to help dispose of CCR and remedy the problems.

The following is a more thorough explanation of the information summarized above that DEP received and largely ignored.

In 2004, DEP's evaluation of long-term ash strategy for the Sutton plant (Hart Exhibit 25) noted that:

> *...[T]hese ponds will eventually have to be emptied and placed in a lined containment to eliminate the leaching of ash products into the ground water system. This is an issue that is not currently being pressed, but it is anticipated that with tighter environmental conditions it will soon be an emergent issue. This is aggravated by the fact that a test monitoring well located 300' from the edge of the [old] ash pond has shown high levels of arsenic during the past two quarterly events.*

Still, even though the 1983 ash basin at the Sutton plant was operationally full, DEP did not begin closure of the basin until required to do so more than a decade later under CAMA. (DEP Tr. vol. 13, 602)

The document also noted that the Sutton pre-ash disposal site was scheduled to be cleaned up but that, under DEP management, the cleanup never occurred, since “little attentions [sic] are currently being placed on [the pre-ash disposal] site.” (Hart Exhibit 25)

Later, DEP did enter into a voluntary Administrative Agreement with DEQ’s Inactive Hazardous Waste Branch to deal with this site, but DEP ultimately terminated the Agreement when DEQ would not accept DEP’s plans for remediation. (See § I.A.2.d)

In the following years, the pattern of acknowledging a need for solutions to their coal ash management problems continued, with recommended solutions being ignored, apparently in order to postpone costs.

In 2004, DEP also retained a third party (MACTEC) to assess short and long term strategies for managing ash at the Cape Fear, H.F. Lee, and Weatherspoon plants due to the facilities’ ash ponds reaching near capacity. (DEP Late-Filed Exhibit 19, 81-374) MACTEC’s assessment for each of these plants follow, as well as other previous assessments by another vendor for Weatherspoon:

- Cape Fear Plant – MACTEC identified excavation and stacking ash from the 1985 ash pond into the 1978 retired ash pond for six and a half years as the best short-term approach for compensating for the 1985 ash pond nearing capacity, with a warning that after that time, there would no more ash storage capacity and one of the long-term options would need to be implemented. (*Id.* at 84) The cost for this proposal which was recommended to start in 2005 was estimated at $2,672,700. (*Id*. at 123) After that initial investment, the cost per year to continue the excavation and stacking was estimated at $411,200. (*Id*.)
    - Two of the longer-term projects and their estimated costs were identified as follows:

- Raise dikes 6 feet, adding three years of usage = $2,320,000, with a cost per year for maintenance estimated at $773,300. (*Id*.)
- Construct a new 20-year pond = $12,262,500 without land cost, with a cost per year for maintenance estimated at $613,125. (*Id*.)

- H.F. Lee Plant – MACTEC recommended for the short-term that DEP relocate the Unit 3 discharge line to the northern side of the pond as soon as possible, then implement a sequence of baffle installations, conducting four cycles of excavating ash and stacking in the western end of the pond, and raising the pond operating level two feet after the last dig and haul cycle, which would extend the life of the pond by 13 years. (*Id*. at 147-48, 193) The cost for the baffle installations in 2004 dollars was estimated at $45,000, and the cost to excavate and stack four cycles of ash over 10.2 years was estimated at $3,534,700. (*Id*. at 193) After that initial investment, the cost per year to continue the excavation and stacking was estimated at $346,540. (*Id*.)

  - Two of the longer-term projects and their estimated costs were identified as follows:

    - Raise dikes 6 feet, adding 6.4 years of usage = $3,172,000, with a cost per year for maintenance estimated at $495,625. (*Id*.)
    - Construct a new 20-year pond = $9,950,000 without land cost, with a cost per year for maintenance estimated at $497,500. (*Id*.)

- Weatherspoon – there were a number of studies conducted at Weatherspoon over the years by different vendors.

  - In 1999, Law Engineering and Environmental Services, Inc. recommended that DEP convert the facility to dry ash disposal at a cost of $12,500,000. (*Id*. at 257)

  - In 2000, the same vendor, after performing modifications to its report at the request of DEP, recommended as its first alternative that for the short-term, DEP vertically extend the dike to increase pond capacity, and for the long-term, convert to a dry ash system and perform further vertical expansion. (*Id*. at 265) The vendor estimated the cost for the combined short-term and long-term alternatives to be $20,865,346. (*Id*. at 308)

- In 2004, MACTEC recommended for the short-term that DEP excavate and stack the ash in Area B that had been used for previous stacking and implement the plan early in 2005. (*Id.* at 358) The estimated cost for excavation and stacking five cycles over 9.8 years until Area B was filled was estimated at $1,979,600, with additional stacking conducted in Area 3 thereafter for an additional two years at a cost of $377,000. (*Id.*) After that initial investment, the cost per year to maintain the plan was estimated at $202,000. (*Id.*)

- Two of the longer-term projects and their estimated costs were identified as follows:

  - Raise dikes 6 feet, adding 4.3 years of usage = $1,655,000, with a cost per year for maintenance estimated at $384,883. (*Id*.)
  - Construct a new 20-year pond = $4,760,000 without land cost, with a cost per year for maintenance estimated at $238,000. (*Id*.)

In February 2006, DEP retained Jacobs Engineering Group, Inc. to determine the modifications and cost required to convert its plants' ash systems to totally dry ash disposal, which resulted in a March report entitled "Coal Fired Plants Conversion of Ash Systems to Dry." (DEP Late-Filed Exhibit 21, 383-421) The estimate for total project costs for the conversion to dry ash handling for each plant were as follows:

- Asheville – **Fly ash** – $3,775,000 – **Bottom ash** – $2,325,000
- Cape Fear – **Fly ash** - $3,775,000 – **Bottom ash** - $2,325,000
- Lee – **Fly ash** – $3,025,000 – **Bottom ash** – $1,425,000
- Mayo – **Bottom ash** – $3,175,000 (dry ash handling of fly ash in place since 1983[4])
- Robinson – **Fly ash** – $3,025,000 – **Bottom ash** – $1,425,000
- Roxboro – **Bottom ash** – $6,100,000 (dry ash handling of fly ash in place since 1990[5])

[4] *See* https://www.bizjournals.com/charlotte/news/2019/12/06/what-insurers-allege-about-duke-energys-knowledge.html
[5] *See* DEP Tr. vol. 13, 557.

- Sutton – **Fly ash** - $4,900,000 – **Bottom ash** – $2,975,000

(*Id.* at 397-400)

In May 2006, DEP staff created a "20 Year CCP Management Plan/Asheville, Robinson, Sutton, Cape Fear, Mayo & Lee Power plants/Business Analysis Package." (*Id. at* 422-66[6]) DEP's Plan, concerned with the fact that DEP's ash ponds are at or near capacity, concentrated on long-term CCP disposal options (2010-2025), provided an evaluation of each of the viable wet and/or dry options, and ultimately provided a single recommended option (monofill) for the management of CCPs on a plant-by-plant basis. (*Id*. at 423) A monofill is a landfill specifically designed to only accept one waste type (such as coal ash) which is placed in a segregated area physically separated from dissimilar waste. Study costs were presented in 2006 dollars and did not include inflation. (*Id*. at 425-26) The recommended alternatives by plant were as follows:

- Asheville – Monofill sited over existing pond over separatory liner – Project total = $16,353,000
- Cape Fear – Monofill sited over existing pond over separatory liner – Project total = $17,286,000
- H.F. Lee – new lined ash pond – Project total = $8,454,000
- Mayo – new monofill on-site – Project total = $19,298,000
- Robinson – new monofill on-site – Project total = $10,325,000
- Sutton – new monofill on-site – Project total = $14,944,000

In August 2008, DEP prepared a summary of topics regarding environmental matters, including the fact that DEP signed on to the Utility Solid

[6] Marked "proprietary and confidential" on first page of document, but the Company did not declare any of the late-filed exhibit as confidential when it was filed on 2 November 2020.

Waste A Activities Group (USWAG) program in December 2007, installing and sampling groundwater monitoring wells for the first time at Asheville, Cape Fear and H.F. Lee, and agreeing to sample the existing wells at Robinson, Sutton and Weatherspoon. (Hart Exhibit 27; DEP Tr. vol. 13, 603)

- In January 2009, DEP's Power Operations Group met to discuss the top 5 environmental issues observed at the facilities. (Hart Exhibit 28) The document indicated that groundwater monitoring revealed elevated levels of various compounds at all DEP coal plants within the ash ponds' review boundaries. (*Id*.) Further, the document noted that boron and manganese were elevated at the Sutton compliance boundary and near the property boundary, that Asheville had elevated levels outside the review boundary, and that DEP would add groundwater monitoring points within the compliance boundary at the Asheville facility. (*Id*.) Similar meetings of the Group in February and March 2009 indicated that elevated levels outside the review boundary were still present at the Asheville and Sutton facilities. (Hart Exhibits 29-30) The documents further indicated an acknowledgement that eliminating the source of groundwater contamination might require dry ash handling, removing ash from the ponds, or installing lined landfills. (*Id*.)
- **(BEGIN CONFIDENTIAL)** [redacted]

[redacted]

- [redacted] **(END CONFIDENTIAL)**

- In December 2009, in its Increased Coal Combustion Product Production Summary, DEP identified the following concerns: 1) DEP landfills and ponds were reaching capacity; 2) new facilities were needed; 3) construction of new ash ponds would most likely not be permitted by new regulations; 4) landfill permitting would most likely meet increased opposition; and 5) groundwater studies could impact technical design requirements. (Hart Exhibit 33) The summary also indicated that Mayo's conversion to dry ash handling was almost complete and was expected to "ameliorate risk" from the planned groundwater study at the facility. (*Id*.)

    - It is apparent from this document, as well as the 2004 and 2006 reports referenced above, that DEP was aware that dry ash conversions could positively affect groundwater contamination associated with its coal ash ponds and had obtained estimates for those conversions. (DEP Tr. vol. 13, 606)

In September 2011, counsel for DEP sent a letter to counsel for the insurance carriers which delineated reasons why the ash pond claims should be resolved and why action to remediate the DEP ash facilities was forthcoming. (Hart Exhibit 34) DEP's counsel articulated the following concerns: 1) there is increased, aggressive regulatory oversight by the State of North Carolina with regard to ash ponds; 2) regardless of when EPA may act, North Carolina is taking aggressive action on coal ash facilities, commencing with the boundary well monitoring required by DEQ at the end of 2010; 3) there are existing regulations (*i.e.*, the North Carolina 2L groundwater rules) requiring corrective action if exceedances are found at the compliance boundaries; 4) while the EPA CCR regulations might be forthcoming, North Carolina regulations already provide for the same potential closure scheme; 5) exceedances of the 2L groundwater standards are already being detected at the relevant DEP ash ponds; and 6) with the passage of time, the threat from these issues will be more expensive. (*Id*.)

- It is clear from DEP's counsel's notification to the insurers that DEP was well aware that it needed to focus on compliance with the DEQ and the State's regulations, and not wait for whatever regulations the EPA may impose in the future. Further, DEP's counsel acknowledged that the threat would only be more expensive with the passage of time.

- In October 2011, counsel for DEP sent a follow-up letter to counsel for the insurance carriers notifying them that DEP found exceedances of the North Carolina 2L groundwater standards in the boundary monitoring wells at the ash pond facilities and that State orders on remediation stemming directly from ash basin contamination seem "inevitable." (Hart Exhibit 35)

d. The Department of Environmental Quality advised DEP that its groundwater monitoring was not being properly managed and required better management practices.

DEP's testimony that it had a positive relationship with the Department of Environmental Quality at all times is not reflected in the record. This section addresses specific transactions between the two parties when the Department of Environment Quality brought DEP to task. In the mid to late 1970s, the adjacent property owner to the east of DEP's Sutton plant expressed concern to DEP and DEQ regarding higher levels of chloride in the neighbor's production wells that it believed were caused by the Sutton plant. (DEP Tr. vol. 13, 598; Hart Exhibit 24B) DEQ records reflect that as early as 1978, DEQ considered the unlined coal ash pond (1971 Ash Pond) at the Sutton plant a potential source of groundwater impacts. (DEP Tr. vol. 13, 598) In 1983, based on these concerns, DEQ required that DEP install a 12-inch clay liner and install and sample seven monitoring wells at the 1971 Ash Basin. (Id.)

In 1978, DEP requested authority from DEQ to construct an ash pond for the Mayo facility within the upper reaches of Crutchfield Branch. (Hart Exhibit 24; DEP Tr. vol. 13, 596) The Army Corps of Engineers (ACOE), based on a draft Environmental Impact Statement, expressed concerns to DEQ related to potential groundwater contamination and the resultant discharge of pollutants downstream of the dam on Crutchfield Branch. (Hart Exhibit 24*)* DEQ advised the ACOE that it would require DEP to complete groundwater studies and provide controls as necessary for the prevention of pollutant materials from entering groundwater. (*Id.)* DEP's third party report, following its study of the proposed location of the Mayo ash pond, recommended that in order to minimize the potential for groundwater impacts and to ensure early detection of such impacts, DEP should maintain observation wells for sampling purposes and make “special efforts” to seal the possible leakage paths where the soil cover is thin or absent such as stream channels and rock outcrops. (DEP Tr. vol. 13, 597)

The record does not reflect whether DEP performed either of the recommendations made to it by the third party. However, based upon groundwater monitoring data, it does not appear that DEP initiated groundwater monitoring at the Mayo plant until 2008, approximately 30 years after it was recommended. (Id. at 598) When groundwater monitoring was finally initiated, it identified both groundwater and surface water impacts to Crutchfield Branch. (Id.)

In April 1986, DEQ issued a letter to DEP indicating that a review of Sutton’s groundwater sampling data of the seven monitoring wells (installed in or about 1983) required that additional groundwater assessment be performed in the area of the canals and coal ash basins. (Hart Exhibit 24B; DEP Tr. vol. 13, 599) DEQ noted the possibility that a violation of the Total Dissolved Solids (TDS) standard at the compliance boundary may exist and that it was probable that the ash ponds have caused concentrations of chloride and TDS that are 50% of the groundwater standard. (Id.) It is unknown whether DEP responded to DEQ’s instructions, but it is obvious that DEQ considered even the “possibility” of a 2L groundwater exceedance to require DEP to perform additional groundwater assessment to determine the extent of the contamination.

In June 1986, DEQ requested that DEP perform a study to demonstrate that the Sutton ash ponds were not contravening and would not contravene groundwater standards. (Id.) DEP proposed installing and sampling six additional monitoring wells to evaluate compliance with the groundwater standards from the discharge canal, cooling lake, and ash ponds. (Id. at 600) After discussions with DEQ, who rejected DEP's proposal of six wells, DEP agreed to install 12 additional wells. (Id.)

In September 1987, as a result of the additional groundwater monitoring, DEQ issued DEP a Notice of Non-Compliance for contravening groundwater standards for TDS and chlorides at and beyond the compliance boundary at the Sutton facility. (Id.) It is unknown whether there was any further correspondence regarding this Notice.

By the late 1980s, DEP was well aware of groundwater contamination concerns at the Sutton and Mayo facilities; was aware that DEQ had significant concerns about the presence of groundwater contamination from coal ash basins; was aware that bottom liners were a potential method to minimize the potential for groundwater impacts; and was aware that DEQ had concerns when concentrations of compounds were elevated from a coal ash pond but did not exceed the groundwater standards and that DEQ expected those conditions to be evaluated further whenever discovered. (Id.)

In June 1991, DEQ's Division of Solid Waste Management's Superfund Section contracted to have a screening site investigation at DEP's Sutton facility conducted to determine whether the facility should be moved into the Federal

Superfund program. (Hart Exhibit 59/Bednarcik AGO Direct Cross Exhibit 22) "Analytical results from groundwater, sediment, and soils samples obtained indicated that significant releases of hazardous contaminants have occurred." (*Id.* at ii of Report) Based on the report and the validation of the data, DEQ recommended to EPA that the Sutton plant be assigned a Medium priority for an Expanded Site Investigation under DEQ's Superfund program. (*Id*. at 1 of 1992 Letter)

On 30 December 1999, upon further inspection, DEQ's Superfund Section advised EPA that it was recommending that the Sutton Plant be considered for further federal action under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) because of the number of drinking water wells that were contaminated and the potential for further release of contaminants to groundwater. (Hart Exhibit 60/Bednarcik AGO Direct Cross Exhibit 23) The DEQ letter reported that numerous drinking water wells within a 1-mile radius of the site, including a community well, had been impacted with site contaminants; inorganic compounds had been detected within several wells; and the monitoring wells on and around the site were also impacted. (*Id*.)

It is unknown what, if anything, was done regarding these groundwater contamination impacts.

On 30 December 2003, DEP entered into a voluntary Administrative Agreement with DEQ to investigate the soil and groundwater conditions within a Former Ash Disposal Area (FADA) at the Sutton Plant. (Hart Exhibit 63/Bednarcik AGO Direct Cross Exhibit 24 at 1-1) A Phase I Remedial Investigation Report submitted in 2004 identified certain data gaps that still needed to be addressed and all parties agreed that a Phase II Remedial Investigation would be conducted in 2005. (*Id*.) The Phase II Remedial Investigation Report recommended that a focused remedial action plan be prepared and submitted to DEQ to address the limited arsenic impacts detected in shallow groundwater within the FADA. (*Id*.)

On 20 August 2007, DEP unilaterally terminated the Registered Environmental Consult Administrative Agreement for the Sutton Plant site, which had been executed for cleanup of hazardous substances under the Inactive Hazardous Substance Response Act, based on DEQ's rejection of DEP's proposed plan for remediation. (Hart Exhibit 65/Bednarcik AGO Direct Cross Exhibit 25) Due to the termination of the Agreement, the Sutton site was transferred from the Responsible Party Voluntary Remedial Action category to the Sites Priority List category of the Inactive Hazardous Sites Inventory. (*Id.*) On 4 January 2008, DEQ identified three reasons why it could not concur with DEP's proposed plan for remediation. First, there were too few samples of the fly ash. A proper evaluation of the contaminant concentrations within the waste is necessary before any proposed containment remedy can be considered. Second, groundwater was already impacted at the Sutton Site, and there were too few samples of the waste material collected to properly analyze whether or not the contamination is still leaching into the groundwater. Third, DEP's attempt to define the extent of the groundwater contaminant plume was questionable. No monitoring wells were installed at or immediately adjacent to the waste material in order to evaluate the highest potential concentrations of contamination in the groundwater, and no groundwater quality data was collected to the south of a well that contained groundwater contamination in excess of remedial goals. (*Id*.) There is no record of DEP acting upon these concerns by the regulator.

In March 2009, DEQ requested information from DEP for all of its coal-fired plants so that DEQ could better assess DEP's data, including maps to show where the wells were located in relation to the various boundaries; summaries of the data; and an evaluation of groundwater standard exceedances in relation to the boundaries. (Hart Exhibit 11) DEQ further inquired as to what actions DEP planned to take as a result of the exceedances in accordance with the corrective action provisions of 15A N.C. Admin. Code 2L.0106. (*Id*.)

As AGO expert witness Hart testified under cross examination, "it's hard for me to believe" that DEQ knew about the location of DEP's wells and that DEP and DEQ were working collaboratively, since DEQ had to request maps from DEP to determine the locations of DEP's wells, and since DEQ had to request an evaluation of the groundwater exceedances in relation to the boundaries.[7] These should have been part of DEP's original submittal. (DEP Tr. vol. 13, 605)

On 18 December 2009, DEQ advised DEP that the wells that DEP had placed inside the compliance boundary were not suitable to determine compliance with the 2L groundwater standards. (Hart Exhibit 11) In its letter, DEQ provided

[7] AGO Expert Witness Hart is the Founder, President and Principal Hydrogeologist of Hart & Hickman, PC, with offices in Charlotte and Raleigh, North Carolina. He has over 30 years of experience in assessing geologic and hydrogeologic conditions and managing and remediating environmental impacts at sites throughout the United States. He has been qualified as an expert in the areas of geology, hydrogeology, fate and transport of contaminants in the environment, contaminant source identification, site assessment and remediation, exposure potential, adequacy of response actions, and remedial methods and costs. He has a Master of Science in Geology, specializing in engineering geology and hydrogeology. (DEP Tr. vol. 13, 530-32)

DEP with recommended additional monitoring well locations. (*Id*.) DEQ further noted that it had concerns regarding some of DEP's existing wells, especially DEP-designated background wells. (*Id*.)

DEP's witness claimed that DEP was historically compliant with all of DEQ's regulations and that it had a cooperative relationship with DEP. (DEP Tr. vol. 19, 185) However, it is apparent from these letters in 2007 and 2009 that DEQ did not consider DEP's groundwater data submittals to be sufficient and had some serious reservations about the manner in which DEP was handling its groundwater monitoring and well placement.

In 2010-2011, based on the USWAG action plan, and a directive from DEQ to establish monitoring wells at its compliance boundaries, DEP finally established a more inclusive groundwater monitoring network and began forwarding data to DEQ. (DEP Tr. vol. 13, 541)

In 2013, prior to CAMA and the federal government's CCR Rule, DEQ filed four lawsuits against DEP alleging violations of the Clean Water Act related to unpermitted discharges of wastewater via seepage from the unlined coal ash basins, and exceedances in violation of North Carolina's 2L Groundwater Standards due to migration of wastewater from the ash basins to groundwater. (*See* Junis Exhibit 1; DEP Tr. vol. 13, 548) Various third party environmental groups also expressed concern with DEP's coal ash management practices and intervened in these cases. (DEP Tr. vol. 13, 548) The lawsuits requested relief in the form of injunctions requiring the Company to address groundwater and wastewater violations at its coal ash impoundments. (Id.)

On 26 August 2014, DEQ issued a Notice of Violation and a Notice of Intent to Enforce to DEP regarding the Sutton facility "for conducting or controlling an activity that caused the concentration of contaminants in groundwater to exceed the groundwater standards adopted under statute." (Hart Exhibit 68/Bednarcik AGO Direct Cross Exhibit 27) On 10 March 2015, DEQ issued its Findings and Decisions and Assessment of Civil Penalties related to that Notice of Violation and Notice of Intent to Enforce. *(Id.)* The Assessment was for identified violations of the 2L groundwater standards for various time periods from October 2009 through 2 October 2014 for seven different contaminants: arsenic, boron, iron, manganese, selenium, thallium, and total dissolved solids. *(Id.)* Based on the number of violations and the number of days those violations occurred, DEQ issued a civil penalty to DEP in the amount of over $25 million.

The parties ultimately entered into a Settlement Agreement wherein Duke Energy paid $7 million in full settlement of all current, prior, and future claims related to exceedances of the 2l groundwater standards, and DEP agreed to implement accelerated remediation at Sutton, Asheville, Belews Creek, and H.F. Lee. *(Id.)*

In sum, it is apparent that DEQ did not consider DEP historically compliant in its operation and maintenance of its coal ash ponds. Instead, DEQ issued multiple warnings as early as the 1970s and continuing through subsequent decades. Further, DEQ brought a lawsuit in 2013 seeking the assistance of the courts to require DEP to comply with the Clean Water Act and the North Carolina 2L groundwater rules. Finally, DEQ followed that with a Notice of Violation and the assessment of a $25 million penalty based on groundwater exceedances of the 2L standards at the Sutton facility.

e. The Company's failure to act and its poor maintenance of its coal ash basins culminated in the 2014 Dan River spill, which led to CAMA.

This history shows a pattern: the Duke Energy Companies continually gained more and more knowledge about the risks of their actions, but they did not make the necessary changes to their coal ash disposal practices. Ultimately, this passive approach to coal ash management culminated in the 2014 Dan River spill from DEC's Dan River plant. After the merger with DEC, DEP did not change its method of handling its coal ash facilities. Instead, DEP continued to study the risk of groundwater contamination, while taking no action to remedy the problem.

In June 2012, DEP prepared a "Significant Environmental Impacts Scoring Sheet" to evaluate the "priority" of plant environmental impacts based upon likelihood of concurrence and the "consequences." (Hart Exhibit 38) The consequence factors were identified as 1) exposure/toxicity, 2) business risk costs, 3) public relations, and 4) regulatory factors. DEP determined a priority score for each environmental impact ranging from 1 to 25, with scores of 15 to 25 being "high priority." (*Id.*)

For each of the DEP facilities, groundwater impacts from ash basins were identified as one of the top five environmental concerns, with high priority rankings for Mayo (23), Asheville (21), Sutton (21), Roxboro (19) and Cape Fear (16), and moderate priority rankings for H.F. Lee (12), Robinson (12), and Weatherspoon (12). Specifically:

- Asheville: the high priority score of 21 included the following comments: iron, manganese, boron hits at the compliance boundary; unlined ponds/manganese/ironhits/increasing regulatory scrutiny.

- Mayo: the high priority score of 23 included the following comments: groundwater/surface water impact.

- Roxboro: the high priority score of 19 included the following comments: groundwater/surface water impact.

- Sutton: the high priority score of 21 included the following comments: groundwater impact; groundwater, soil and/or surface water impacts; on Inactive Hazardous Site list; boron and manganese in monitoring wells.

Despite the fact that the significance of groundwater contamination was in the top five (of out of more than 100 to consider) environmental concerns at each facility, DEP took — and continued to take —little effort to address these groundwater impacts until after the Dan River spill and the enactment of CAMA, when DEP was forced to address the groundwater impacts.

In April 2013, DEP considered information regarding various regulatory programs, including groundwater standards and monitoring, as it relates to the addition of other wastewater streams discharged into the ash basins. (Hart Exhibit 39) DEP noted that the boron, TDS and chlorides in FGD wastewaters being discharged into the ash basins increased the risk of boron and chloride groundwater impacts, which could then result in site investigations and corrective actions required by DEQ. (*Id*.) Despite this knowledge, DEP continued to discharge wastes other than coal ash into its basins and did nothing to abate the groundwater impacts.

In 2013, DEP staff met to discuss ash basin closure strategy and noted that while the CCR Rule was not expected before 2014, *state requirements exist now* (emphasis added). (Hart Exhibit 40) The document further noted that it was important to move forward with ash basin closures to minimize environmental risk and costs associated with maintaining an ash basin for an extended period of time; that dewatering the ash basins would reduce or eliminate seepage; that capping the basins soon would help begin the process of natural attenuation or other means to reduce contaminants in groundwater; and that ash basin closure was creating increased attention and scrutiny, which would only increase while the ash basins have no approved closure plans and "reasonable efforts to close them are not underway." (*Id.*)

In November 2013, Duke Energy prepared a summary of groundwater monitoring data which included all of the DEP facilities. (Hart Exhibit 41) This document acknowledged that there had been exceedances of the groundwater standards at the compliance boundary of all the DEP facilities. (*Id*.) The following identifies the constituents that were in exceedance of the 2L groundwater standards at each facility at that time, identified receptors, and the actions completed in relation to those exceedances:

- Asheville:
    - Compounds above Standards: chromium, nitrate, selenium, thallium, boron, chloride, iron, manganese, sulfate, TDS, and pH.
    - Receptors: Five water supply wells identified side-gradient to plant.
    - Actions Completed: completed receptor survey and connected two residences to municipal water because of high iron and manganese in a water supply well.

- Cape Fear:
  - Compounds above Standards: arsenic, cadmium, selenium, boron, iron, manganese, sulfate, TDS and pH.
  - Receptors: Cape Fear River; no risks identified.
  - Actions Completed: None. Comments: Entire facility retired; field investigations for ash basin closure began in summer 2013.

- H.F. Lee:
  - Compounds above Standards: arsenic, chromium, boron, iron, TDS, manganese, and pH.
  - Receptors: Neuse River; no risks identified.
  - Actions Completed: None. Comments: Coal units recently closed; field investigations for ash basin closure to begin in summer 2013.

- Mayo:
  - Compounds above Standards: cadmium, thallium, chromium, iron, manganese, TDS, and pH.
  - Receptors: Mayo Creek; identified as distant from ash basins.
  - Actions Completed: None; dry fly ash conversion to be completed in 2014, pond to remain open for other wastewater streams.

- Robinson:
  - Compounds above Standards: arsenic, chromium, sulfate, TDS, and pH.
  - Receptors: Lake Robinson.
  - Actions Completed: None; coal fired unit recently closed. Separate inactive basin does not have groundwater monitoring network.

- Roxboro:
  - Compounds above Standards: chromium, iron, manganese, sulfate, TDS, and pH.
  - Receptors: Hyco Lake.
  - Actions Completed: None; monofill is being developed over east ash basin to cap and close basin, the west ash basin is active and receives bottom ash.

- Sutton:
  - Compounds above Standards: antimony, arsenic, cadmium, lead, selenium, thallium, boron, iron, manganese, sulfate, TDS, and pH.
  - Receptors: Cape Fear Public Utility (CFPU) has two wells on property adjacent to plant. There are also non-potable

industrial wells in area. In 2013, CFPU and DEP agreed to two-year project to connect the area served by the wells to Wilmington city water.

  - Actions Completed: Because of boron plume, two phase investigation completed in 2011 per DEQ; many of these wells incorporated into current well network. Monitoring began in early 1990s and wells were either within compliance boundary or distant from ash basins. Boron detected above NC Standard at the property line.

- o Weatherspoon:
  - Compounds above Standards: iron, manganese, and pH.
  - Receptors: On-site cooling pond.
  - Actions Completed: Coal units have closed. Ash basin field investigations have been completed and closure design is nearly submitted.

The document indicates that Duke Energy believed the exceedances for iron, manganese, and pH are from naturally occurring conditions (which is not consistent with actual data as noted herein) and notes that iron, manganese, pH, and TDS "only have secondary MCLs," implying that exceedances of these compounds are not of significance. Based on the level of the exceedances found, there was and is a potential risk to human health and the environment. (DEP Tr. vol. 13, 616)

On 13 January 2014, (after the merger) DEC staff advised the Company's Senior Management Committee that both DEC's and DEP's coal ash basins were discharging to groundwater in all locations. (Hart Exhibit 16) This committee presentation warned that scrutiny regarding closure was increasing while "reasonable efforts to close basins were not underway." (*Id.*) The document also provided estimated costs for remaining dry ash conversion for some of DEP's facilities. (*Id.*)

These estimated costs for dry ash conversion, along with estimated costs provided in November 2009 (Hart Exhibit 32), and those provided in 1999 and 2006 (DEP Late-filed Exhibit 19) for comparison were as follows:

- Asheville – Dry fly ash and bottom ash
  - $41 million – 2014 cost estimate
  - **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL)**
  - $6,100,000 – 2006 cost estimate

- Cape Fear – Dry fly ash and bottom ash
  - $6,100,000 – 2006 cost estimate

- H.F. Lee – Dry fly ash and bottom ash
  - $4,450,000 – 2006 cost estimate)

- Mayo – Dry bottom ash only
  - $6.7 million - 2014 cost estimate)
  - **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL)**
  - $3,175,000 for bottom ash only – 2006 cost estimate

- Robinson – Dry fly ash and bottom ash
  - $4,450,000 – 2006 cost estimate

- Roxboro – Dry bottom ash only
  - $90 million - 2014 cost estimate
  - **(BEGIN CONFIDENTIAL)** [redacted] **(END CONFIDENTIAL)**
  - $6,100,000 for bottom ash only – 2006 cost estimate

- Sutton – Dry fly ash and bottom ash
  - $7,875,000 – 2006 cost estimate

- Weatherspoon – Dry fly ash and bottom ash
  - $12,500,000 – 1999 cost estimate

In sum, during this period of time, DEP staff, its management, and even its counsel knew that DEP's ash basins were contaminating groundwater and acknowledged that it should begin seeking alternative disposal methods, such as liners and dry ash handling. Even so, DEP continued to put coal ash in unlined basins (with the exception of the new ash basin at Sutton which DEQ had required be lined), failed to properly close its basins, failed to move toward safer methods of storing coal ash, and failed to resolve its groundwater contamination issues prior to being required to do so under CAMA and the CCR Rule. Further, due to its delay in converting to dry ash handling, the costs of doing so continued to rise from 2006 to today.

In February 2014, a stormwater pipe beneath one of DEC's coal ash basins at its Dan River plant failed. (Hart Exhibit 3) As a result, tens of thousands of tons of coal ash spilled into the Dan River over six days. The spill coated the banks of the river with waste as far as sixty-two miles downstream. (*Id.*) The spill led to an investigation by EPA and the United States Attorney's office. The 2015 Federal Criminal action's Joint Factual Statement provides a detailed review of the Duke Energy Corporation's negligence over time in allowing this devastating spill to occur. (*Id.*)

On 12 March 2014, Duke Energy Corporation's President and CEO, accepting the Company's responsibility for the Dan River ash discharge, announced to the Governor and DEQ its intent to develop an "updated, comprehensive plan that protects the environment and provides safe, reliable and cost-effective electricity to North Carolinians." (Hart Exhibit 1) The plan proposed was comprised of both near-term and longer-term actions. (*Id.* at 2)

The Dan River spill led the General Assembly to enact the Coal Ash Management Act of 2014 (CAMA) later that year. N.C.G.S. §§ 130A-290 *et. seq.* As the Commission found in its Order in E-7, Sub 1146, the General Assembly enacted CAMA in response to the spill of an estimated 39,000 tons of coal ash into the Dan River. (DEP Tr. vol. 13, 548-49) In short, Duke Energy's management of its ash basins was so imprudent that the legislature was forced to intervene in order to address the problems created by the Company's admitted criminal negligence.

f. The Coal Ash Management Act

CAMA's major provisions include the following:

- Prioritization of ash basins with timelines for their closure – the statute classified DEP's Asheville and Sutton sites as high risk, requiring their ash basin closure by 1 August 2019. The remainder of the sites were later classified as low risk.
- Establishment of a groundwater monitoring network at each site.
- Prohibition on the construction of new and expansion of existing ash basins.
- Prohibition on discharges of stormwater to ash basins on or after 31 December 2018 for inactive facilities or 31 December 2019 for active facilities.
- Conversion of facilities to dry ash handling by 31 December 2018 and conversion to bottom ash handling by 31 December 2019 (or retirement of the facility prior to that time).
- Accelerated timelines for submission of groundwater assessment plans and corrective action plans.
- Accelerated timelines to perform receptor surveys to identify water supply wells in the area of the coal ash basins and to provide permanent

water supplies for households within a 0.5 mile radius of a compliance boundary of an ash basin.

- Accelerated timelines for identification, permitting, sampling, and possible corrective action for all discharges from coal ash basins including toe drains and groundwater seeps.

(DEP Tr. vol. 13, 549-51; N.C.G.S. §§ 130A-309.200 to .231)

As required by CAMA, and with input from DEQ, DEP established a site-specific groundwater monitoring network at each of the North Carolina DEC facilities during the first quarter of 2019. (DEP Tr. vol. 12, 76) Witness Bednarcik advised that these networks required a "significant" number of wells to be installed. (Id. at 77) The requirement of the number of wells at each site came from DEP "going back and forth with NCDEQ." (Id. at 82)

g. 2015 Federal Criminal Case of Criminal Negligence Related to DEP's Asheville, Cape Fear and H.F. Lee Plants.

In February 2015, the U.S. Attorney filed charges against DEP and the other Duke Energy entities with violations of the Clean Water Act. (Hart Exhibit 2) DEP's criminal negligence related to three of its plants: Asheville, Cape Fear and H.F. Lee. DEP pled guilty to criminal negligence in Federal Court in May 2015 to: 1) one count related to the Asheville Steam Electric Generating Plant for allowing the unauthorized discharge of two seeps to flow into engineered toe drains at the base of its 1964 coal ash basin which was ultimately discharged into the French Broad River, from at least 31 May 2011 to 30 December 2014; 2) two counts related to the Cape Fear Plant for DEP's negligent failure to maintain equipment at its coal ash basins when it violated a condition of its permit with respect to the maintenance and inspection of risers within two of its coal ash basins from 1 January 2012 to 24 January 2014; and 3) one count related to the H.F. Lee Plant's discharges of coal ash and coal ash wastewater from an unpermitted drainage ditch from at least 1 October 2010 to 30 December 2014. (Hart Exhibits 2-3) For all four counts, DEP admitted, when it pled guilty to criminal negligence, that it had failed "to exercise the degree of care that someone of ordinary prudence would have exercised in the same circumstances." (*Id.*)

During the sentencing hearing, the U.S. Attorney argued to the Court that in addition to the large penalties, there was a critical need for a five year term of probation with a Court-appointed monitor to oversee and supervise the Company. (Hart Exhibit 2 at 95) The U.S. Attorney considered such oversight necessary in order to prevent the continuation of the Company's historical negligence and to ensure that there was a change in the "culture" of the Company and its "poor management of the coal ash basins." (*Id.* at 96-97) The Court agreed and placed the Company on a five year term of probation with supervisory oversight by a Court Appointed Monitor. (*Id.*)

h. EPA's October 2015 Coal Combustion Residuals Rule

In 2015, the EPA promulgated the Coal Ash Combustion Residual Rule (CCR Rule) to address groundwater contamination associated with coal ash impoundments. The Rule added new requirements for coal ash surface impoundments and landfills as follows:

- Mandatory groundwater monitoring around surface impoundments and landfills;

- Liner requirements for new surface impoundments and landfills to protect groundwater;
- Groundwater cleanup from coal ash contamination;
- The closure of unlined surface impoundments that are polluting groundwater;
- The closure of surface impoundments that fail to meet engineering and structural standards or are located too close to a drinking water source;
- Restrictions on the location of new surface impoundments and landfills so that they cannot be built in sensitive areas such as wetlands and earthquake zones; and
- Proper closure of all surface impoundments and landfills that will no longer receive CCRs.[8]

EPA advised that two of the key goals of the Rule include the prevention of future catastrophic failures of coal ash impoundments and the protection of groundwater from contamination. (*See* Footnote 8.) In order to accomplish the first goal, each surface impoundment must comply with five location restrictions: 1) placement of at least five feet above the uppermost aquifer; and NO placement in 2) wetlands, 3) within fault areas, 4) in seismic impact zones, or 5) in unstable areas. The Rule requires owners of existing CCR units that cannot meet any of these location restrictions to close. (*Id.*) It is noteworthy that every DEP site subject to the CCR Rule failed to meet at least one of these location restrictions, requiring the closure of the affected ash basins. (Hart Exhibits 51, 53-58)

[8]*See* https://www.epa.gov/coalash/frequent-questions-about-2015-coal-ash-disposal-rule#4

In order to accomplish the second goal, the Rule includes provisions for mandatory groundwater monitoring of landfills and impoundments. (*See* Footnote 8.) The Rule prescribes that a monitoring system include a minimum of one upgradient and three downgradient monitoring wells, with additional wells installed as necessary to accurately represent the groundwater quality. (*Id.*) The first phase of groundwater monitoring under the Rule is Detection Monitoring in order to determine whether specific constituents common to coal ash groundwater contamination are present. (*Id.*) The Appendix III constituents considered by the EPA to be the leading indicators of whether there is migration from a CCR unit include: boron, calcium, chloride, fluoride, pH, sulfate, and total dissolved solids. (*Id.*)

The Rule requires that if there is found a statistically significant increase over background concentrations for any of these constituents in any well, then the facility must begin the next phase of groundwater monitoring, Assessment Monitoring. (*Id.* at 7) Assessment monitoring requires that additional Appendix IV constituents be sampled: antimony, arsenic, barium, beryllium, cadmium, chromium, cobalt, fluoride, lead, lithium, mercury, molybdenum, selenium, thallium, and Radium 226/228 combined. (*Id.*)

It is notable that all of the DEP sites requiring CCR groundwater monitoring have been found to have statistically significant increases over background concentrations and were required to move to the Assessment monitoring phase. (Harts Exhibits 51 at 53-58) Witness Wells attributes this movement to the Assessment phase to the difference between where the detection boundaries are set under the 2L groundwater Rules and the CCR Rule. (DEP Tr. vol. 19, 484) The 2L groundwater Rules employ the key detection point at a compliance boundary that is set 500 feet from the waste boundary. (Id.) The CCR Rule is stricter, not allowing for this distance, but requiring that detection be determined at the waste boundary, while also introducing some additional constituents to be tested. (Id.)

Witness Bednarcik testified that there was a "significant" number of wells installed at the DEC sites pursuant to the CCR Rule. (DEP Tr. vol. 12, 77) When queried as to whether the CAMA and CCR networks were interchangeable, Bednarcik advised that in some instances the same wells may be used for both CAMA and CCR and some wells may not, depending upon the specific requirements of groundwater monitoring required under each law. (Id. at 83-84)

Witness Wells testified that DEC hired third-party contractors to assist with the installation of the groundwater monitoring networks, but DEC retained oversight. (DEP Tr. vol. 19, 477) The final networks ultimately implemented had to be approved by DEQ. (Id. at 478) There is evidently some overlap of the wells used for the two groundwater monitoring networks, but the DEP witnesses were not able to provide any specifics as to the number of overlapping wells and where the wells were located. (Id. at 483) Witnesses Bednarcik and Wells were also unable to explain the need for so many wells, or provide any specifics as to how many of the wells pre-existing the formation of the networks were able to be utilized in the new monitoring networks. Witness Wells opined that the cost of a well varied, but that his best guess would be that each well would cost somewhere in the $10,000 to $40,000 range. (DEP Tr. vol. 19, 489)

i. DEQ's 1 April 2019 Closure Determinations at two DEP sites are evidence of DEP's historical imprudent response to groundwater contamination.

Under CAMA, two of DEP's coal-fired plants, Mayo and Roxboro, were ultimately categorized as low risk sites. (Bednarcik AGO Direct Cross Exhibit 21; Bednarcik AGO Rebuttal Cross Exhibit 2) On 1 April 2019, DEQ rejected DEP's proposed closure plans for these sites and required that the ash ponds be excavated, primarily based on each site containing an extensive groundwater contamination plume. (*Id*.)

- The Mayo site contains a boron groundwater plume above the 2L groundwater standard, extending beyond the compliance boundary downgradient of the ash basin around Crutchfield Branch. (Bednarcik AGO Rebuttal Cross Exhibit 2 at 10)
- The Roxboro site contains a contaminated groundwater plume above the 2L groundwater standards, extending beyond the compliance boundary along the northern edge of the impoundment, along the majority of the length of the East Ash Basin. (Bednarcik AGO Direct Cross Exhibit 21 at 10)
    - DEQ also noted that boron, sulfate, and total dissolved solids have been detected greater than the 2L standards in bedrock monitoring wells underlying the West Ash Basin and downgradient in the transition zone. (*Id.*)
    - DEQ further noted that the area of the plume requiring remediation is immense, and that even 100 years beyond completion of closure, the area of the plume requiring

> remediation would remain extensive under DEP's proposed closure options. (*Id.* at 12)

As the 1991 EPRI Study indicated, the more leachate that enters the groundwater system can lead to higher groundwater concentrations and further migration distances in groundwater over time. (Hart Exhibit 15) That is exactly what happened at these sites that DEQ investigated based on DEP's proposed closure options. Although the other sites have not undergone such a review, it is highly likely that similar results would have been found at a number of those sites prior to excavation due to the fact that all of the sites are within five feet of the uppermost aquifer and some are in wetlands. (Hart Exhibits 51-58)

*** * ***

A summary of the extensive evidence of DEP's non-actions bears repeating:

- As far back as 1978, the power industry was aware of the dangers posed by coal ash disposal practices, and an EPA report warned that groundwater contamination from coal ash ponds like the ones used by DEP were a problem of great significance. (Hart Exhibit 18)
- In the 1960s through the 1980s, one or more coal ash basins that were functionally full were taken out of service or only used for very limited purposes at DEP's Asheville, Cape Fear, H.F. Lee, Roxboro, and Sutton plants without being properly closed. (DEP Tr. vol. 13, 602, 697-98)
- In the 1970s and the 1980s, DEP became directly aware of the environmental and ecological consequences of groundwater contamination due to the fish consumption advisory at Hyco Lake,

ultimately installing its first dry ash handling system to meet new permit limits for selenium in 1990. (DEP Tr. vol. 13, 557)

- Beginning in the mid to late 1970s, DEQ began to warn DEP of its concerns about groundwater contamination from DEP coal ash disposal. (Hart Exhibit 24B)
- In 1978, DEP's request to construct an ash pond for the Mayo facility within Crutchfield Branch met with resistance from the Army Corps of Engineers because of potential groundwater contamination. (Hart Exhibit 24)
- In 1983, DEQ's authorization of DEP's request to construct a new ash pond at the Sutton site required that DEP install its first 12-inch clay liner in the pond, as well as install and sample seven monitoring wells at the 1971 Ash Basin. (Hart Exhibit 24B)
- No later than 1983, DEP was directly aware of the positive value of installing a liner in its ash ponds. (Hart Exhibit 24B)
- In 1986, DEQ requested that DEP perform a study to demonstrate that the Sutton ash ponds were not contravening and would not contravene groundwater standards. DEP's proposal to install six additional monitoring wells to do the study was rejected, with DEQ requiring the installation of twelve wells. (Hart Exhibit 24B)
- In 1987, DEQ issued DEP a Notice of Non-Compliance for contravening groundwater standards for total dissolved solids and chlorides at and beyond the Sutton compliance boundary. (Hart Exhibit 24B)

- In the 1990s, DEQ investigated the Sutton plant as a potential Superfund site and found a number of contaminated drinking wells. (Hart Exhibit 59)
- In 1991, a study identified that environmental risks were present specifically in areas like the geologic region of the Piedmont, where many of DEP facilities were located. (Hart Exhibit 15)
- In 1996, DEP reported to its insurers that its coal ash basins had contaminated groundwater at six sites. (DEP Tr. vol. 13, 606)
- In 1999, a third party vendor recommended that DEP convert the Weatherspoon facility to dry ash disposal at a cost of $12,500,000. (DEP Late-Filed Exhibit 19, 257)
- In 2000, the same third party vendor modified its recommendations at DEP's request, and recommended vertically extending the dike for the short-term and convert to a dry ash system for the long-term, at a combined cost of $20,865,346. (DEP Late-Filed Exhibit 19, 308)
- In 2004, many of DEP's coal ash ponds were nearing or at capacity. (DEP Late-Filed Exhibit 19, 81-374)
- In 2004 and 2006, DEP retained third party vendors to assess short and long-term strategies for managing ash at their coal ash ponds and received cost estimates for dry ash handling, as well as other alternative methods of disposal for all of its coal ash facilities. (*See* § I.A.2.c for the estimated costs proposed.)

- In 2009, DEP acknowledged that all of its coal plants had contaminated groundwater. (Hart Exhibit 28)
- Yet it was not until after the Dan River spill in 2014 that DEP took action to change its practices.

There is extensive evidence that DEP's inaction was unreasonable, that DEP illegally polluted groundwater in violation of the 2L groundwater rules, and that cost estimates in 2004 and 2006 for dry ash handling and other alternative methods of disposal were much lower than those requested by DEP today and should be considered in light of DEP's unreasonable past conduct.

B. DEP's Violation of North Carolina's 2L Groundwater Rules and Pollution of Groundwater via Its Unlined Coal Ash Basins Was Not Reasonable or Prudent.

In 1979, North Carolina implemented laws to protect the land, as well as the surface and ground waters of the State. 15A N.C. Admin. Code 02L.0101 (1979). These 2L groundwater rules impose strict liability on any person whose activities cause the concentration of any substance in groundwater to exceed the limits of that substance's specific 2L groundwater standards. 15A N.C. Admin. Code 02L.0103(d) (2018).

As evidenced by the history of DEP's coal ash management, DEP has known for decades that its coal ash basins were polluting groundwater in violation of the 2L groundwater rules, or at least that the basins would eventually do so. The evidence further demonstrates that DEP unreasonably managed its unlined basins—mismanagement that eventually resulted in admitting guilty to criminal negligence and the damage and leakage of the risers at the Cape Fear plant at not one, but two, of its ash basins for two years; the unauthorized discharge of pollutants from the coal ash basins into the French Broad River at the Asheville plant for over three years; and the discharge of coal ash and coal ash wastewater from an unpermitted drainage ditch at the H.F. Lee plant for more than four years. (Hart Exhibit 3)

DEP could have prevented or at least have taken corrective action to address these violations. DEP's internal historical evidence herein reflects that it was aware of its non-compliance even earlier than 1996, when DEP informed its insurers that it was aware that it could face liability for violating the 2L groundwater rules at all of the plants where it had done testing. Thereafter, it took little to no action to control the groundwater exceedances or eliminate the source of a contamination at that time. It only eventually did so when DEQ required it pursuant to CAMA and the CCR Rule. (DEP Tr. vol. 13, 543)

By not acting on its own internal knowledge in a timely way, and by ignoring the warnings of groundwater exceedances at several of its plants as early as the 1970s and 1980s, DEP did not act reasonably or prudently. By failing to adhere to proper coal ash management, DEP incurred costs that it could have avoided. (Id.) For example, if DEP had built lined landfills or converted to dry-ash handling sooner, it would not have had to pay to excavate ash that it could have already put in lined landfills years earlier. (Id. at 543-45)

Likewise, if DEP had built lined landfills at its plants sooner, it could have avoided the cost of transporting ash to off-site landfills. Because of DEP's delay in building lined landfills, it has incurred transportation costs to meet CAMA's deadlines for closing coal ash basins. (DEP Tr. vol. 15, 1259)

Further, if DEP had installed dry ash handling systems at its plants in 2006, the cost to do so would have been significantly less than it is today. (DEP Late-Filed Exhibit 19)

In sum, DEP acted unreasonably by failing to alter its coal ash management practices by continuing to put ash into unlined basins after DEP knew that doing so would violate the law by contaminating groundwater and after acknowledging that it knew that other methods of disposal would avoid risk of ash basin non-compliance.

1. DEP violated the state's environmental laws.

The evidence shows that DEP contaminated the groundwater around its basins in violation of the 2L groundwater rules. As our Supreme Court has held, breaking environmental laws is "unreasonable." *Glendale Water*, 317 N.C. at 40-41, 343 S.E.2d at 907-08. Evidence of DEP's environmental violations, DEP's criminal convictions, and the events that followed from them, present "affirmative evidence" that challenge "the reasonableness of [DEP's] expenses." *Bent Creek*, 305 N.C. at 76, 286 S.E.2d at 779. This showing of DEP's mismanagement is more than enough to require DEP to prove that it incurred its coal-ash costs reasonably. The Commission should reject the notion that it is legal under the 2L groundwater rules to pollute groundwater as long as the pollution is eventually cleaned up. Cleaning up pollution does not negate the violation of the 2L groundwater rules that occurs when a polluter causes exceedances outside compliance boundaries.[9] Instead, the 2L groundwater rules provide that *"[n]o person shall conduct . . . any activity which causes the concentration of any substance*" in groundwater to exceed the 2L standards. 15A N.C. Admin. Code 02L.0103(d) (emphasis added). Beyond the compliance boundaries, exceedances are illegal unless they are naturally occurring. *See* 15A N.C. Admin. Code 02L.0102(3), .0107(a), (b).

Thus, cleaning up pollution does not show compliance with the law; it shows the opposite. Our Supreme Court has concluded that cleaning up pollution under the 2L rules becomes necessary only if "*groundwater quality has been degraded"* in violation of the law*, i.e*., but for the groundwater having been degraded in the first place, there would have been no need for cleaning it up. *Cape Fear River Watch v. N.C. Envtl. Mgmt. Comm'n*, 368 N.C. 92, 94, 772 S.E.2d 445 (2015) (emphasis added) (quoting 15A N.C. Admin. Code 02L.0106(a)). Based on the 2L groundwater rules, any exceedance, even within a compliance boundary, should be treated as a warning, with action taken to ensure that the exceedance does not reach the compliance boundary and thereby prevent a violation from occurring. (DEP Tr. vol. 13, 570; Hart Exhibit 24B) Similarly, a federal court has held that the 2L rules are "*strict liability regulations*" that "prohibit any activity" that causes "a concentration of [a] substance above the state's groundwater limits." *Rudd v. Electrolux Corp.*, 982 F. Supp. 355, 365 (M.D.N.C. 1997) (emphasis added).

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[9] If no compliance boundary is deemed to exist under the 2L groundwater rules, or if the exceedance occurs in bedrock, then any exceedance at that site or in bedrock is most often an automatic violation. (15A N.C. Admin. Code 02L .0107(k)(3)(C); DEP Tr. vol. 13, 561-62)

2. The Commission has a duty to determine the reasonableness of the costs by assessing any evidence that a utility's costs stem from illegal conduct.

Furthermore, the Commission has the statutory duty to determine whether a utility's costs are reasonable, N.C. Gen. Stat. § 62-133(b)(3), and evidence that the costs were incurred to address violations of the State's environmental laws is material and appropriate for the Commission to consider in the reasonableness determination. *See Glendale Water*, 317 N.C. at 40-41, 343 S.E.2d at 907-08 (holding that costs incurred because of violations of environmental laws are unreasonable).

The Commission may not abdicate its statutory duty to determine whether a utility has satisfied the requirements of the ratemaking statute. Instead, the Commission must "make[ ] its own independent conclusion supported by substantial evidence" on whether proposed rates are reasonable. *State ex rel. Utils. Comm'n v. Carolina Util. Customers Ass'n* (*CUCA*), 348 N.C. 452, 466, 500 S.E.2d 693, 703 (1998) (quoting *State ex rel. Utils. Comm'n v. State*, 239 N.C. 333, 344, 80 S.E.2d 133, 141 (1954)) (internal quotation marks omitted).[10]

Accordingly, the Commission has a duty to assess DEP's reasonableness based on all of the "relevant, material and competent evidence" in the record, N.C.G.S. § 62-133(c), including evidence of violations of environmental law,

[10] *See also N.C. Power*, 338 N.C. at 419-22, 338 S.E.2d at 900-02 (holding that the Commission must decide whether utilities' costs were reasonable); *State ex rel. Utils. Comm'n v. Carolina Water Serv.*, 335 N.C. 493, 503, 439 S.E.2d 127, 132 (1994) (holding that "the Commission cannot simply substitute the . . . criteria of another agency as a substitute for its own determination"); *State ex rel. Utils. Comm'n v. Edmisten*, 291 N.C. 451, 464, 232 S.E.2d 184, 191-92 (1977) (holding that in setting rates, the Commission should not defer to accounting treatment adopted by utility).

regardless of whether DEP admits to wrongdoing, and regardless of whether a court has expressly held that violations have occurred.

The history of actions relating to DEP's improper maintenance of its coal ash basins provides vivid evidence that the costs are not normal costs of retiring the systems but rather result from DEP's unreasonable practices. A quote from a U.S. Attorney at the sentencing hearing in the 2015 federal criminal negligence case is enlightening as to what was learned during their investigation of the Company's practices: the "culture and poor management of the coal ash basins" by the Company "had a deleterious effect cumulatively on the watersheds and wetlands throughout North Carolina." (Hart Exhibit 2 at 95-96) Based on the federal government's concerns that the Company would resort to its old ways, the Court placed the Company on a rare 5-year probation with oversight by a Court-appointed Monitor. (*Id.*)

In 2013, the State sued to enjoin the Company's violations of the 2L groundwater rules, with several environmental groups intervening. (DEP Tr. vol. 13, 548; Junis Exhibit 1) Before the State's 2013 lawsuits reached judgment, however, the Dan River spill occurred. In response to the spill, to stop the Company from further polluting the waters of this state, the legislature enacted CAMA. CAMA secs. 3(a)-3(f), 2014 N.C. Sess. Laws at 830-62.

After CAMA was enacted, a trial court, at the Company's request, granted partial summary judgment on the State's claims. The court stated that the Company's compliance with CAMA (along with certain additional measures by

Duke) had already largely granted the State the relief it sought in its complaints: stopping the Company from polluting the state's groundwater.

As these events show, CAMA made it unnecessary for the court in the 2013 case to decide whether DEP violated the 2L rules, as long as DEP complies with CAMA and DEQ's implementation of CAMA. But, given that CAMA was a response to DEP's unreasonable and imprudent management of its coal ash basins, the passage of the legislation should not be cited as reason for the Commission to ignore evidence of DEP's mismanagement.

Further, it is important to note that CAMA's and the CCR Rule's major focus is the protection of groundwater and the abatement of groundwater contamination. DEP has had groundwater contamination issues for decades and these issues continue to exist. As learned in 1991, more leachate allowed to enter the groundwater system can lead to higher groundwater concentrations and further migration distances in groundwater over time. (Hart Exhibit 15) This has proven to be true with the extensive contaminated groundwater plumes at Mayo and Roxboro, as noted by DEQ in their April 2019 closure determinations at these sites. (Bednarcik AGO Direct Cross Exhibits 21; Bednarcik AGO Rebuttal Cross Exhibit 2) Groundwater contamination has been the key area of DEC's non-compliance and poor coal ash management, being handled imprudently and unreasonably for decades, resulting in immense groundwater contamination plumes. This level of groundwater contamination requires much greater corrective action and increased cost than would have been incurred had the groundwater contamination not existed or had been remedied when the signs pointed to its existence. (DEP Tr. vol. 13, 544-45)

In sum, the Commission has a duty to determine whether DEP's conduct was unreasonable given extensive evidence that DEP illegally polluted groundwater in violation of the 2L groundwater rules.

3. DEP must show that its costs were reasonable in light of the evidence that the basins were not reasonably managed and increased the cost to close them and dispose of CCR properly.

Under the legal standard in *Bent Creek*, the burden now shifts to DEP to demonstrate the extent to which its costs were reasonable despite affirmative evidence that DEP incurred its coal-ash costs due to its own unreasonable conduct. DEP has not carried this burden, because its evidence is inconclusive and does not quantify with precision the effect of DEP's unreasonable management on the amount of the costs.

"The absence of . . . evidence in the record does not benefit Duke, for the burden is upon Duke to establish the reasonableness of the rate increases it has proposed." *State ex rel. Utils. Comm'n v. Duke Power Co.*, 285 N.C. 377, 389, 206 S.E.2d 269, 277-78 (1974).

Enforcing this burden makes perfect sense. When DEP seeks rate increases, it bears the burden of persuasion, because it is the party that has "knowledge of the facts."[11] *Peace v. Employment Sec. Comm'n*, 349 N.C. 315,

[11] The General Assembly's decision in sections 62-134(c) and 62-75 to put the burden on utilities like Duke is consistent with the general principles that guide the allocation of litigation burdens. In litigation, "the party who asserts the affirmative" or "the party with peculiar knowledge of the facts" generally bears the burden of proof. *Peace*, 349 N.C. at 328, 507 S.E.2d at 281.Where, as here, a utility seeks a rate increase under section 62-134, the utility is both the party that seeks affirmative relief and also the party that has the most knowledge about its costs and historical practices.

328, 507 S.E.2d 272, 281 (1998). DEP's access to information, and the duties conveyed by that knowledge, were in sharp relief here. Gaps in the record are the result of DEP's own decisions about what evidence to present. DEP mostly limited its evidence to discuss only how it has managed coal ash in 2018 through 2020. (DEC Tr. vol. 14, 190-219) Thus, to the extent that the record is spotty on how DEP's conduct before 2014 affected the current costs, DEP is responsible for that gap in the evidence.

The burden is DEP's, and when the "evidence [is] of insufficient probative force" to support a rate increase, the rate increase should be denied. *State ex rel. Utils. Comm'n v. Motor Carriers' Traffic Ass'n*, 16 N.C. App. 515, 520, 192 S.E.2d 580, 583 (1972).

C. Even Under the Standard Applied by the Commission in Other Cases, the Impact of DEP's Unreasonable Management on Costs Can Be Quantified in Certain Respects.

There have been and will continue to be substantial costs incurred in order to remedy CCR-related environmental violations and to prevent risk of future violations. These costs will primarily relate to improving groundwater contamination issues through corrective action plans and the closure of ponds pursuant to both CAMA and the CCR Rule. DEP labels its coal ash costs as regulatory costs to meet CAMA and CCR Rule requirements, however, they are also reflective of DEP's non-compliance with longstanding environmental regulations.

As all the parties and Commissioners know, the Supreme Court has not yet issued its decision in the appeal of this Commission's order in DEP's previous general rate case. The AGO continues to take the position, consistent with its arguments in that case, that the burden of proof lies on DEP to quantify what portions of its coal ash costs were reasonable and what portions were not. But even under the standard that the Commission has recently applied to determine whether coal ash costs are imprudent, which places this burden upon the challenger, there are specific costs that should be disallowed.

The standard was most recently described by the Commission in the 24 February 2020 Final Dominion Order (2020 Dominion Order). The Commission required “a detailed and fact-specific analysis” that not only 1) “identif[ies] specific and discrete instances of imprudence;” and 2) “demonstrate[s]” the existence of prudent alternatives; but 3) also “quantif[ies] the effects by calculating imprudently incurred costs.” (*Id.* at 129) The challenger must present evidence that quantifies which costs might have been avoided if an alternative approach to managing coal ash had been used during the past decades. (*Id.*)

AGO witness Hart identified and quantified three adjustments to specific costs deferred during the period. He calculated the adjustments in Steps A, B, and C. The first adjustment (Step A) would not allow DEP to recover expenditures made to connect certain properties near its coal plants to alternate water supplies. (DEP Tr. vol. 13, 695) The second adjustment would remove the portion of the costs associated with closing ash basins that were taken out of service sometime between the 1960s and 1980s but not previously closed. The third adjustment would reduce the remainder of the expenditures to reflect the increase in the cost today over the cost in an earlier period based on inflation. (Id. at 712-13)

Step A calculates that the requirement that Duke connect all households in some areas near its coal plants to alternate water supplies added an estimated $3.48 million to the total coal ash expenditures for the system. (Id.) The calculation is based on costs that were shown in DEP witness Bednarcik's direct testimony that identified expenditures from 1 September 2017 through 30 June 2019.[12] (DEP Tr. vol. 12, 33, 43-55) Witness Hart testified that it is unheard of for a company to be required to connect properties to an alternate water supply unless those properties' water supplies have been impacted by contamination. (DEP Tr. vol. 13, 694) If DEP had determined the extent of groundwater problems at its coal plants by establishing reliable groundwater monitoring and performing adequate evaluations of water supply receptors in the areas near its facilities prior to being required to do so by CAMA, the need to provide alternate water connections would have been avoided. (Id. at 695)

Moreover, these alternate water connection costs were caused by DEP's imprudence even at properties where no evidence has been presented of contamination bearing DEP's fingerprint. After the Dan River spill, it came to light that groundwater problems were an on-going problem at all of DEP's coal plants, and the contamination occurring near DEP's ash basins became notorious. (Hart Exhibits 2-3, 16, 38, 40) The requirement that DEP provide an alternate water supply was prompted by diminished trust in DEP's operations. DEP's failure to

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[12] Witness Hart used the information available from DEP witness Bednarcik's direct testimony when he prepared his testimony, and the amount he identifies is specific. However, it would be adjusted if the Commission agrees with the reasoning, in order to update the amount through 29 February 2020 using later work papers from DEP, and to adjust the related amount recovered for rate of return during deferral of the costs, and to quantify the North Carolina retail share. (DEP Tr. vol. 12, 33)

maintain the basins in compliance with groundwater requirements and its admission to criminal negligence at some of its plants were widely publicized. (Hart Exhibits 2-3)

Step B makes another specific adjustment to DEP's coal ash expenditures based on an evaluation of each facility and exclusion of costs for basins that should have been taken out of service and closed long ago at the Asheville, Cape Fear, H.F. Lee, Roxboro, and Sutton coal stations. Over $196 million of the system costs during the deferral period are attributable to these basins that were out-of-use and functionally full prior to 1990. It is not reasonable for current and future ratepayers to pay for the closure of these older ash basins, and a specific adjustment can be calculated for these closure costs. (DEP Tr. vol. 13, 699)

AGO witness Hart analyzed each coal station to determine the appropriate adjustment:

- At Asheville, he found that all of the expenditures deferred for ash basin closure were associated with the 1964 ash basin that went out of service in 1982. The costs for excavation of the newer 1982 basin at Asheville were included in the previous rate case. Therefore, the adjustment of 100% was made in this case, for an exclusion of $99.1 million. (Id. at 697)
- At Cape Fear, witness Hart found that four basins were out of use by 1985 and one basin was used until 2012 when the coal station was closed. An adjustment of 51% was made based on the proportion of ash in the older basins, for an exclusion of $21.3 million. (Id.)

- At H.F. Lee, witness Hart found that three basins were out of use by 1980 and one was used until 2012 when the coal station was closed. An adjustment of 27% was made based on the proportion of ash in the older basins, for an exclusion of $23.6 million. (Id.)
- At the Mayo, Robinson, and Weatherspoon stations, witness Hart found at each that only one basin was used and it has continued to receive ash until recently, so none of the costs were excluded in this step. (Id. at 698-99)
- At Roxboro, witness Hart found that the East basin was essentially out of use by 1983. An adjustment of 35% was made based on the proportion of ash in the older basin, for an exclusion of $5.3 million. (Id. at 698)
- At Sutton, witness Hart found that the former ash disposal area (a lay of land area or LOLA) was out of use by 1972, and the Old Ash Basin was essentially out of use by 1985. An adjustment of 46% was made based on the proportion of ash removed from the former ash disposal area and the Old Ash Basin, for an exclusion of $47.2 million. (Id.)

In Step C, witness Hart made a third type of adjustment to reflect the increase in clean-up costs over time. This adjustment is a reasonable estimate of the response costs specifically attributable to inflation between earlier points in time, when DEP was aware of the issues with groundwater contamination at its ash basins, and the time when it started substantially planning for basin closure in 2014. (DEP Tr. vol. 13, 699) Witness Hart calculated the effect of inflation on costs assuming that the same work would have been done had DEP taken measures earlier – although he believed that his calculation underestimates the potential cost reduction because lower cost options likely would have been available at those earlier times. (Id. at 699-700) In fact, based on DEP's late-filed exhibits, the costs in 2006 for dry ash handling installation were significantly less than today's cost. (DEP Late-filed Exhibits 19, 21)

Hart began this calculation with the $415,937,510 in coal ash costs identified in Ms. Bednarcik's testimony. (DEP Tr. vol. 13, 699) Then, Hart adjusted the amount to remove the water supply connection costs of $3,481,096 discussed in Step A and to remove the oldest basin costs of $196,579,596 discussed in Step B, leaving a balance of $215,876,813. (Id.) Hart identified several points in time when the evidence shows that DEP had reason to perform work in response to groundwater issues. From these factors, Hart identified the reduction in costs if work had started in those earlier years, measured by the comparing the costs now reduced by the rates of inflation over that time. (Id. at 700-01)

The reduction of costs are shown below for the points of time identified by Hart:

- 1992 (when groundwater contamination was already known to exist for several years) – $90.7 million;
- 1996 (when groundwater contamination claims were made by DEP to its insurance company) – $75.7 million; and
- 2009 (when groundwater impacts were confirmed at all DEP facilities as a result of USWAG monitoring) – $17.7 million.

(DEP Tr. vol. 13, 700-01)

Thus, witness Hart testified DEP's costs for the system would be reduced by an additional amount of between approximately $17.7 million and $90.7 million if the process of closing ash basins had started earlier, when DEP had identified groundwater contamination. Witness Hart added this $17.7 to $90.7 million range from Step C to the costs of alternate water supplies in Step A (an estimated $3.48 million) and the costs of closing older basins in Step B (an estimated $196.6 million) to determine the total minimum disallowance. (Id.)

The range in excluded costs are summarized here:

Starting Point	**1992**		
Step A and B Excluded Costs		$	200,060,692
Step C Excluded Costs		$	90,679,573
Total Excluded		**$**	**290,740,265**
Starting Point	**1996**		
Step A and B Excluded Costs		$	200,060,692
Step C Excluded Costs		$	75,657,753
Total Excluded		**$**	**275,718,445**
Starting Point	**2009**		
Step A and B Excluded Costs		$	200,060,692
Step C Excluded Costs		$	17,735,012
Total Excluded		**$**	**217,795,704**

(Id. at 701)

In addition, Public Staff witness Garrett[13] provided two bases for specific disallowances of costs. (DEP Tr. vol. 15, 1222) First, Garrett reviewed the Charah contract with DEP and determined that $33,670,054 of the fulfillment fee DEP paid

[13] Public Staff witness Garrett is the Secretary/Treasurer of Garrett and Moore, Inc. located in Cary, N.C., which specializes in engineering services for power and waste industries. He is a licensed Professional Engineer with 30 years of experience engineering coal ash management projects, cost engineering, operational projects, and alternative analysis. (DEP Tr. vol. 15, 1212)

to Charah related to the disposal of ash from Sutton, Cape Fear, H.F. Lee, and Weatherspoon at the Brickhaven structural fill project should be disallowed because it was not reasonable and prudent. (Id.) Second, Garrett re-examined the facts and determined that transportation costs associated with the off-site disposal of ash from the Asheville site to the R&B Landfill were not reasonable and prudent and opined that $50,238,630 of these costs should be disallowed. (Id. at 1259)

Public Staff witness Moore[14] provided another basis for a specific disallowance of costs. (Id. at 1208) Moore reviewed the costs of the Cape Fear and H.F. Lee beneficiation units. Moore opined that the termination of the contractor H&M and the employment of the contractor Zachry to construct the beneficiation units was unreasonable and that $130,384,392 of the costs paid for these two beneficiation units should be disallowed. (Id.)

Finally, Public Staff witness Lucas[15] provided evidence of three more bases for specific disallowances of cost. (DEP Tr. vol. 15, 1502) The first specific disallowance relates to the groundwater extraction and water treatment at the Asheville, H.F. Lee, and Sutton plants, as well as land purchases at the Asheville, H.F. Lee, and Mayo plants to mitigate the risk of spreading groundwater contamination. These costs for the period of September 2017 through December 2019 amount to $1,240,328 on a system basis. (Id. at 1503) As Lucas testified,

[14] Public Staff witness Moore is the President of Garrett and Moore, Inc., which specializes in engineering services for power and waste industries. He is a registered Professional Engineer with over 30 years of experience engineering coal ash management projects, including operational cost projections and alternative analysis. (DEP Tr. vol. 15, 1211)

[15] Public Staff witness Lucas has been an engineer with the Public Staff – North Carolina Utilities Commission for over 20 years. Lucas has a M.S. in Environmental Engineering with over thirty years of engineering experience. (DEP Tr. vol. 15, 1526)

these costs exceed what CAMA would have required in the absence of environmental violations and should be disallowed. (Id.)

The second specific disallowance discussed by Lucas relates to the requirement by the legislature that DEP provide either a permanent water supply or bottled water to those residents in the vicinity of the coal ash impoundments based on the unacceptable risk to those residents from the coal ash constituents. Lucas testified that those costs, which should be disallowed, amounted to $1,087,612 on a system basis from the period of September 2017 through December 2019. (Id. at 1503-04)

The third specific disallowance discussed by Lucas relates to the issue of a permanent water supply alternative of the installation, operation and maintenance of a water treatment system based on the same rationale as stated above. (Id.) Lucas testified that those costs, which should be disallowed, amounted to $2,774,583 on a system basis from the period of September 2017 through December 2019. (Id. at 1504-05)

D. It Is Appropriate for the Commission to Monitor the Outcome of Duke's Insurance Litigation Seeking Coverage for Coal Ash Costs.

On 29 March 2017, the Company, including DEP, filed a complaint for declaratory judgment against a number of insurance companies to enforce its rights under 37 occurrence-based, excess-level third-party liability insurance policies sold to Duke between 1971 and 1986 (the Insurance Case). (DEP Tr. vol. 11, 936-37; DeMay AGO Direct Cross Exhibit 1) In the Insurance Case, the Company asserted that "Duke is legally compelled to investigate and remediate alleged or actual environmental property damage caused by coal combustion residuals (CCRs) at 14 coal-fired power plants in North Carolina and one coal-fired power plant in South Carolina." (DeMay AGO Direct Cross Exhibit 1 at 2)

It has long been recognized in North Carolina law that a general liability policy that covers property damage, nothing else appearing, applies to injury to the state's natural resources.[16] The Company's position is that it has a strong claim in the Insurance Case and has, in fact, settled with at least one insurance company as of this hearing. (DEP Tr. vol. 11, 944) Witness DeMay testified that this recent settlement is "limited in nature and scope," pending settlements or litigation successes with the other insurance companies. (Id.)

In the Insurance Case, the Company is seeking coverage for remedial actions required under CAMA including removal of CCRs from impoundments, placing impermeable caps on impoundments, conducting groundwater monitoring, implementing corrective action to restore groundwater quality, providing permanent water supplies to residents near CCR impoundments, and the costs associated with commercial reuse of ash (*i.e*., beneficiation). (DeMay AGO Direct Cross Exhibit 1) Witness DeMay testified that the litigation is currently at various stages of discovery, with a trial expected to commence at the beginning of 2021. (DEP Tr. vol. 11, 943)

In the Commission's February 2018 Duke Energy Progress Order (DEP 2018 Order), the Commission made the following Findings of Fact:

> 63. It is appropriate to require that DEP, within 10 days of the resolution by settlement, dismissal, judgment or otherwise of the litigation entitled Duke Energy Carolinas, LLC, et al. v. AG Insurance SA/NV, et al., Case No 17 CVS 5594, Superior

[16] *See C.D. Spangler Constr. Co. v. Industrial Crankshaft & Engineering Co*., 326 N.C. 133, 155, 388 S.E.2d 557, 571 (1990).

> Court (Business Court), Mecklenburg County, North Carolina (Insurance Case), file a report with the Commission explaining the result and stating the amount of insurance proceeds to be received or recovered by DEP. This reporting requirement shall apply even if the case is appealed to a higher court.
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> 64. It is appropriate to require DEP to place all insurance proceeds received or recovered by DEP in the Insurance Case in a regulatory liability account and to hold such proceeds until the Commission enters an order directing DEP regarding the appropriate disbursement of the proceeds. The regulatory liability account should accrue a carrying charge at the overall rate of return authorized for DEP in this Order.
>
> 65. If meritorious concerns are raised by any party to this docket, or by the Commission, regarding the reasonableness of DEP's efforts to obtain an appropriate amount of recovery in the Insurance Case, it is appropriate to require DEP to bear the burden of proving that it exercised reasonable care and made reasonable efforts to obtain the maximum recovery in the Insurance Case.

(DEP 2018 Order at 20.)[17] These Findings of Fact were later echoed in the decretal portion of the Order. (*Id.* at 228)

In the current case, it would be appropriate for the Commission to make similar findings and to continue to monitor the outcome of the Insurance Case.

E. If DEP Is Allowed to Recover Coal Ash Costs from Ratepayers, It Should Not Be Allowed to Add a Rate of Return to Those Costs.

Assuming *arguendo* that DEP has demonstrated that the coal ash costs are recoverable, it is not appropriate or lawful for the Commission to authorize DEP to add a rate of return on the costs during deferral and amortization. DEP's proposed increase includes not only the costs of closing coal ash ponds, but *also* adds a rate

[17] Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase *In the Matter of Application by Duke Energy Progress, LLC, for Adjustment of Rates and charges Applicable to Electric Utility Service in North Carolina*, Docket No. E-2, Sub 1142, issued February 23, 2018 (DEP 2018 Order).

of return to those costs as they are deferred and again as they are amortized. (DEP Tr. vol. 13, 325) DEP witness Smith testified that DEP seeks to recover $440.1 million from North Carolina retail ratepayers for coal ash closure costs that have been deferred from 1 September 2017 through 29 February 2020, less approximately $4.2 million that was collected in prior rates. (DEP Tr. vol. 13, 324) Included in the balance for the period is $40.98 million for the "financing cost" based on the Company's weighted average cost of capital. (DEP Tr. Vol. 13, 323-26; Smith Second Settlement Exhibit 1 at NC-1102) The Company proposes to amortize the cost of coal ash disposal (including the added rate of return during deferral) over a five-year period, then include the unamortized balance in ratebase so that DEP will continue to earn a rate of return until the costs are fully recovered. (DEP Tr. vol. 13, 327-28) The total added to the Company's annual cost of service is about $111 million: $88 million in amortization (including the expenditures and financing during deferral) and about $23 million more for rate of return during the amortization period. (Id.)

It is not fair or lawful for DEP to be allowed to profit from its coal ash closure activities. Yet this is exactly what DEP's proposal to add rate of return during coal ash deferral and amortization would do. DEP would earn a rate of return as it spends to close impoundments and dispose of waste that has accumulated for decades.

DEP's proposal is inconsistent with the law concerning what kind of costs can go into the ratebase. Two categories of expenditures may be captured in rates: those that make up a utility's ratebase, and those that make up its operating expenses.[18] Only the utility's ratebase, not its operating expenses, is eligible to be multiplied by a rate of return.[19] Our Supreme Court has enforced the distinction between ratebase and operating expenses. On at least three earlier occasions, it has reversed the Commission for putting property that was not used and useful into a utility's ratebase.[20]

Here, DEP must show that its coal ash costs meet the test for inclusion in ratebase. DEP has failed to do that because it has not shown that the costs are for property that is used and useful for providing current service to consumers.

1. Coal Ash costs were not spent on property that is used and useful for providing current utility service.

The North Carolina Supreme Court has noted that "[t]here is but one ratebase, namely, the ratebase defined by the ratemaking statute.[21] In *Thornburg II*, this Court explained that, for everything other than construction work in progress, a two-part test decides what goes into a utility's ratebase:

- First, the Commission must "determine the reasonable original cost of the property."[22]

[18] *See, e.g.*, *State ex rel. Utilities Com. v. Thornburg* (*Thornburg I)*, 325 N.C. 463, 467 n.2, 385 S.E.2d 451, 453 n.2 (1989); N.C. Gen. Stat. § 62-133(b).
[19] *Thornburg I*, 325 N.C. at 475, 385 S.E.2d at 458; N.C. Gen. Stat. § 62-133(b)(5).
[20] *State ex rel. Utilities Comm'n v. Carolina Water* (*Carolina Water*), 335 N.C. 493, 507-08, 439 S.E.2d 127, 135 (1994) (reversing Commission's decision to put retired wastewater treatment plant into ratebase); *State ex rel. Utils. Comm'n v. Pub. Staff-N.C. Utils. Comm'n* (*Carolina Trace*), 333 N.C.195, 202, 424 S.E.2d 133, 137 (1993) (reversing Commission's order that put into ratebase a wastewater connection that a utility was no longer using); *State ex rel. Utilities Com. v. Thornburg* (*Thornburg II*), 325 N.C. 484, 495, 385 S.E.2d 463, 469 (1989) (reversing Commission's decision to put costs to construct excess nuclear facilities into ratebase); *see also State ex rel. Utils. Comm'n v. Morgan*, 277 N.C. 255, 273, 177 S.E.2d 405, 417 (1970) (holding that it was erroneous, before statutory amendment that authorized the practice, to put construction work in progress into ratebase because the work in progress did not produce income during the test period).
[21] *Morgan*, 277 N.C. at 268, 177 S.E.2d at 414.
[22] 325 N.C. at 491, 385 S.E.2d at 466-67 (citing N.C. Gen. Stat. § 62-133(b)(1)).

- Second, the Commission must determine whether the property is "used and useful, or to be used and useful within a reasonable time after the test period."[23]

The Court concluded, "If the costs in question do not meet both parts of the test, the costs may not be included in the ratebase for ratemaking purposes."[24] The Court's *Carolina Trace* opinion illustrates what it means for property to be used and useful for providing current utility service.[25] One issue in *Carolina Trace* was whether the Commission had properly included in a utility's ratebase the entire cost of a sewer connection that had been used for a time, but was abandoned by the time the rate case was filed.[26] The Court reversed the Commission's order, because it was erroneous to allow the utility's ratebase to include any completed facility that is not used and useful for providing current service.[27]

Here, DEP has failed to show which (if any) of its deferred coal-ash disposal costs were *property used and useful* for providing current service. Coal ash costs do not fit any definition of *property*. Black's Law Dictionary defines property as "[c]ollectively the rights in a valued resource such as land, chattel, or an intangible" and as "[a]ny external thing over which the rights of possession, use, and enjoyment are exercised."[28] DEP's coal-ash costs, in contrast, mainly involve expenditures made for basin closure and treating contaminated groundwater. (DEP Tr. Vol. 12, 46-47, 49, 51, 54-55) Those costs are typically accounted for as

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[23] *Id.*
[24] *Id.*
[25] 333 N.C. 195, 424 S.E.2d 133.
[26] *Id*. at 197-99, 424 S.E.2d at 134-35.
[27] *Id*. at 202-03, 424 S.E.2d at 137.
[28] *Property*, Black's Law Dictionary 1410 (10th ed. 2014).

operating expenses. In fact, DEP referred to its costs as expenses when it initially requested authority to defer them for recovery in later periods. (McManeus/Speros AGO Cross Exhibit 1 at 4)

Further, most or all of the costs are not expenditures for property "used and useful . . . in providing the service rendered to the public within the State." (DEP Tr. vol. 12, 46-55)[29] Indeed, the evidence indicates that the costs were related to disposal of waste from power generation for electrical service that was provided in the past, instead of for property that is used and useful for providing electric service to current customers. (Id.; DEP Tr. vol. 13, 625-85, 694) None of the expenditures that DEP has made at *active* coal plants for ongoing operations (*e.g.*, such as for dry ash conversion or water treatment) are included in the costs at issue here. DEP called its active plants' costs "non ARO" costs and accounted for them separately. (DEP Tr. vol. 13, 329)

As a matter of law, investments in facilities that are not used to provide current service, and that will never again be in use, may not be included in a utility's ratebase. In *Carolina Water*, the North Carolina Supreme Court held that it was an error of law for the Commission to accord ratebase treatment to a utility's investment in a retired wastewater treatment plant. The Court stressed that "[t]here is no statutory authority for including in ratebase costs from a completed plant that is no longer used and useful."[30]

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[29] N.C.G.S. § 62-133(b)(1); (b)(3).
[30] *Carolina Water*, 335 N.C. at 508, 439 S.E.2d at 135 (citing *Carolina Trace*, 333 N.C. at 202, 424 S.E.2d at 137).

Likewise, in *Carolina Trace*, the property at issue was constructed, used for a time, and then rendered unnecessary before the company's next rate proceeding.[31] Because the property would never again be in use, the Court held that it would not ever be allowed to enter the utility's ratebase.[32]

As these cases show, the fact that property might have been used and useful for past service does not make that property used and useful for current service. Current service is the statutory test.[33]

DEP's coal ash costs are expenditures made to dispose of many decades' worth of coal-ash waste and to close coal ash basins related to electric service provided to customers in the past. (DEP Tr. vol. 13, 694) Indeed, most of DEP's expenditures relate to coal stations that have been retired or converted to natural gas and the ash ponds have been retired for years or decades. (Id.)

In fact, DEP is asking its current customers to pay to close ash ponds and dispose of waste generated by coal that was burned as long ago as the 1950s. (Id. at 644) That past activity is in no way used and useful for providing current utility service to customers. It is unfair—and unlawful—to make today's customers pay DEP a return on expenditures made now relating to electric service to past customers.

Moreover, the costs to address coal ash do not become investment in ratebase simply because the expenditures are useful for environmental compliance. Environmental-compliance costs can be reasonable (and thus

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[31] 333 N.C. at 197-98, 424 S.E.2d at 134-35.
[32] *Id*. at 202-03, 424 S.E.2d at 137.
[33] N.C. Gen. Stat. § 62-133(b)(1).

recoverable as costs) and still fail the higher standard for generating a return: being used and useful for providing current electric service. There is a difference between the "used and useful" test for inclusion of costs in ratebase and the "reasonableness" test that applies to expenses. For example, in *Thornburg II*, the Supreme Court affirmed the Commission's conclusion that certain expenditures on facilities were prudent,[34] but the Court held that, as a matter of law, the utility could not receive a return on those expenses, because the facilities at issue were not used and useful for current service.[35]

Indeed, the Commission has previously followed this distinction in a 1994 general rate case for Public Service Company of North Carolina.[36] That case addressed the costs of cleaning up environmental contamination at Public Service Company's manufactured-natural-gas plants.[37] The Commission held that the utility should not receive a return on clean-up costs at sites that were not providing current service to customers.[38]

As these decisions illustrate, DEP's costs for closing its coal ash basins and disposing of the waste are not used and useful for providing current service, and it is not appropriate to authorize DEP to recover a rate of return on the costs.

[34] 325 N.C. at 493, 385 S.E.2d at 468.
[35] *Id*. at 496, 385 S.E.2d at 470.
[36] Order Granting Partial Rate Increase *In the Matter of Application of Public Service Company of North Carolina, Inc., for an Adjustment of its Rates and Charges*, issued 7 October 1994 in Docket No. G-5, Sub 327 (1994 Public Service Order) at 20-23.
[37] *Id.* at 23.
[38] *Id.*

2. An unconstitutional "taking" would not result from denying DEP a rate of return on the costs.

DEP's affiliate DEC recently argued – incorrectly – that the Commission must allow recovery of a rate of return on coal ash costs during deferral and amortization of the costs or an unconstitutional "taking" of property would occur. (That argument was posited by DEP's affiliate DEC in a rate case brief submitted 4 November 2020 in Docket No. E-7, Sub 1214 at pages 2, 55, 77-78.) Constitutional limits on ratemaking do not require the courts to do a piecemeal examination of how rates are fixed. *Duquesne Light Co. v. Barasch* (*Duquesne*)*,* 488 U.S. 299, 309-10, 313 (1989). "The economic judgments required in rate proceedings are often hopelessly complex and do not admit of a single correct result. The Constitution is not designed to arbitrate these economic niceties." (*Id.* at 314.) In *Duquesne*, expenditures made by two Pennsylvania utilities for a planned nuclear plant were found to have been prudent and reasonable when made, but, on cancellation of the plant, the costs were disallowed under the Pennsylvania regulatory scheme because the investments were not for property "used and useful in service to the public." (*Id.* at 301.) The Court concluded that a disallowance would not be considered "confiscatory" based on the specific element of cost that was disallowed; rather, any particular cost must be considered as part of the overall rate determination. "If the total effect of the rate order cannot be said to be unreasonable, judicial inquiry . . . is at an end." *Id.* at 310 (quoting *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 602 (1944)). The effect of the disallowance on rates was considered to be within a zone of reasonableness that was not constitutionally objectionable. (Id. at 311-312).

Based on the *Duquesne* decision, our North Carolina Supreme Court observed that the United States Supreme Court has "clearly held that a state scheme of utility regulation does not 'take' the utility's property in violation of the fifth and fourteenth amendments simply because it disallows recovery of capital investment in a cancelled plant not "used and useful in service to the public," even though the expenditures were prudent and reasonable when made. *Thornburg 1*, 325 N.C. at 471, 385 S.E.2d at 455-56.[39]

Similarly, if DEP argues here that a denial of rate of return on coal ash expenditures imposes an unconstitutional taking, that argument would be an improper piecemeal attempt to limit the Commission's ratemaking authority. The impact would not be confiscatory unless the impact caused the rates as a whole to be outside a zone of reasonableness, and constitutional review is "at an end" unless the impact reaches that threshold.

3. DEP's creation of an Asset Retirement Obligation does not entitle the Company to a return on expenditures that are not "property used and useful" in providing utility service.

When DEP records an asset retirement obligation (ARO) for financial accounting purposes, the information is pertinent to *investors,* but it does not change how the costs must be accounted for in ratemaking. Indeed, the creation or existence of an ARO does not require that DEP's coal-ash removal costs are "property used and useful, or to be used and useful within a reasonable time after

[39] The Court concluded that the Commission has the authority to permit recovery of capital invested in cancelled plant through amortization by applying a broad interpretation of what is allowed as "reasonable operating expenses," but observed that the statute permits recovery *but no* return on reasonable operating expenses. *Id* at 475, 385 S.E.2d at 458.

the test period, in providing the service rendered to the public,"[40] and no exception to the used and useful requirement is provided for an ARO in the ratemaking statute.[41]

Rather, the accounting treatment adopted by a utility—even when approved by the Commission—cannot and does not "create a liability upon the company's customers or establish the company's right to recover from its customers the amounts so entered."[42] As DEP witness Riley testified, "…for regulated entities, accounting follows ratemaking, not the other way around." (DEP Tr. vol. 13, 377)

The Commission itself has recognized this principle in other cases, including in the recent Dominion rate case when it explained that a company's labeling of costs for accounting purposes does not transform the costs into expenditures for "property used and useful."[43] The principle was also recognized in 2003 when the Commission authorized the use of deferral accounting for legal AROs created by utilities to address financial accounting requirements, but specified that the net effect of the deferral accounting must be to continue the Commission's currently existing accounting and ratemaking practices.[44] The 2003 Order granted the deferral request but directed in particular that the intent and outcome of the deferral process shall be to continue the Commission's currently existing accounting and ratemaking effect of the deferral accounting allowed which

[40] N.C. Gen. Stat. § 62-133(b)(1).
[41] *Id.*
[42] *Edmisten*, 291 N.C. at 464, 232 S.E.2d at 191; accord *N.C. Power*, 338 N.C. at 421-22, 450 S.E.2d at 901-02; *Carolina Trace*, 333 N.C. at 203, 424 S.E.2d at 138.
[43] 2020 Dominion Order at 133.
[44] Order Granting Motion for Reconsideration and Allowing Deferral of Costs issued 12 August 2003 in Docket No. E-2, Sub 826 admitted in evidence as Smith AGO Cross Exhibit 6 (2003 ARO Order) at 12-13.

"shall be to reset [DEP's] North Carolina retail ratebase, net operating income, and regulatory return on common equity to the same levels as would have existed had [the ARO financial accounting requirements] not been implemented."[45]

This distinction – which the Commission drew in 2003 – is the same one that applies here. DEP's accounting treatment of its coal ash costs does not control the Commission's treatment of those costs for ratemaking purposes.

4. The rate of return DEP proposes to recover on coal ash expenditures is not "working capital" that may be included in ratebase simply because the expenditures were made from utility funds.

DEP also argues that the rate of return it proposes to recover on coal ash costs is "working capital" that may be included in ratebase under reasoning discussed by our Supreme Court in *VEPCO*. (DEP Tr. Vol. 13, 903)[46] In that case, our Supreme Court held that working capital may be included in a utility's ratebase.[47] The Court defined working capital as "the utility's own funds reasonably invested in . . . materials and supplies and its cash funds reasonably so held for the payment of operating expenses, as they become payable."[48]

The Commission rejected this argument in its recent order in the Dominion case.[49] The Commission explained that the holding in *VEPCO* does not state, nor does it signify, that all capital supplied by investors must be included in the utility's ratebase.[50] For an asset to get rate-base treatment, it must not only have been

[45] *Id* at 12.
[46] *State ex rel. Utilities Commission v. Virginia Electric & Power Co*. (*VEPCO*), 285 N.C. 398, 206 S.E.2d 283 (1974).
[47] *Id*. at 414-15, 206 S.E.2d at 295-96.
[48] *Id.*
[49] 2020 Dominion Order at 132-33.
[50] *Id.*

funded by the utility's investors, but must also meet the requirement in N.C.G.S. § 62-133(b)(1) that the costs be for "property used and useful." The label used for accounting practices does not transform the costs into expenditures that meet that definition.[51]

The Commission's reasoning in the 2020 Dominion Rate Order is consistent with the Supreme Court's order in *Morgan*, where the Court made clear that the mere fact that investors have funded certain expenses is not enough to allow a utility to put those expenses in its ratebase.[52] There, the Court held that the Commission erred by giving a utility a return on its investments in a facility that was still under construction and not yet in use. If all capital supplied by investors were entitled to be treated as working capital, as DEP appears to contend here, the *Morgan* Court would have allowed the investments at issue to go into the utility's ratebase. The Court, however, did the opposite. Taken as a whole, the lesson of *Morgan* is a reminder that investor-supplied funds are a necessary—but not sufficient—precondition to putting property into ratebase.

The Supreme Court has applied this same analysis in multiple other cases. Again and again, it has held that a utility's ratebase excluded property that was presumably funded by investors, but that failed the additional requirement of being used and useful:

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[51] *Id.*
[52] 277 N.C. at 273, 117 S.E.2d at 417.

- In *Thornburg II*, the issue was whether a utility's ratebase could include the parts of common facilities that served three abandoned units at the Shearon Harris nuclear plant.[53] This Court held that as a matter of law, these excess facilities were not used and useful.[54]

- In *Carolina Water*, a utility was facing unrecovered costs that resulted from the early retirement of a wastewater-treatment plant.[55] The Court held that including these costs in the utility's ratebase was erroneous. That outcome, the Court held, would allow the utility "to earn a return on its investment at the expense of the ratepayers."[56]

- In *Carolina Trace*, as noted earlier, the Court barred a utility from receiving a return on any part of its investment in a sewer connection that was constructed and abandoned during the time between the utility's rate cases.[57] Because of that timing, the property never qualified as used and useful. [58]

As such, our Supreme Court has never recognized any exceptions to the "used and useful" requirement. There is no working-capital exception. There is no exception for funds supplied by investors. There is no statutory authority for the Commission to grant a return on expenditures that are not used and useful for

[53] 325 N.C. at 486, 385 S.E.2d at 464.
[54] *Id*. at 495, 385 S.E.2d at 469.
[55] 335 N.C. at 507, 439 S.E.2d at 135.
[56] *Id.* at 508, 439 S.E.2d at 135.
[57] 333 N.C. at 203, 424 S.E.2d at 137.
[58] *Id*.

service during the test year.[59] DEP has not shown that its coal ash expenses meet the used-and-useful requirement, and the "working capital" argument must fail.

5. It would be an error of law to allow a rate of return based on discretionary authority.

It would be an error of law to grant a rate of return on coal ash costs based on the exercise of discretionary authority. The discretion granted to the Commission by N.C.G.S. § 62-133(d) is not so broad that it allows the Commission to ignore specific requirements in the ratemaking formula. North Carolina law makes clear that the Commission has no discretion to give rate-base treatment to something that is not used and useful for providing service to customers now or within a reasonable time. The Court has made this point on multiple occasions.[60]

In *Carolina Trace*, for example, the Commission held that a particular sewer connection was not used and useful for serving customers. Despite that fact, the Commission allowed the value of the sewer connection to be put into the utility's ratebase, reasoning that this rate-base treatment would allow the utility to "recover its investment in a plant that at one time was used and useful to provide service." *Carolina Trace*, 333 N.C. at 200, 424 S.E.2d at 136.

The decision was reversed on appeal and the Court held that the utility could not recover its investment, let alone receive a return on that investment. *See id.* at 202, 424 S.E.2d at 137. The Court found it pivotal that "[t]here is no statutory authority anywhere within Chapter 62 that permits the Commission to include in

[59] *Carolina Trace*, 333 N.C. at 203, 424 S.E.2d at 137; accord *Carolina Water*, 335 N.C. at 508, 439 S.E.2d at 135 (citing *Carolina Trace*).

[60] *See Carolina Water*, 335 N.C. at 507-08, 439 S.E.2d at 135; *Carolina Trace*, 333 N.C. at 202, 424 S.E.2d at 137; *Thornburg II*, 325 N.C. at 495, 385 S.E.2d at 469.

ratebase any completed plant . . . that is not ‘used and useful’ within the meaning of this term as defined in our case law.” *Id.* at 203, 424 S.E.2d at 137; accord *Carolina Water*, 335 N.C. at 508, 439 S.E.2d at 135 (citing *Carolina Trace*, 333 N.C. at 202, 424 S.E.2d at 137).

The Court has followed this same analysis in several other decisions that have reversed the Commission for giving rate-base treatment to expenditures that were not used and useful. *See, e.g.*, *Carolina Water*, 335 N.C. at 507-08, 439 S.E.2d at 135; *Thornburg II*, 325 N.C. at 484, 385 S.E.2d at 463. In none of those decisions has the Court ever suggested that the Commission has discretion to expand a utility’s ratebase beyond the specific definition of that term in section 62-133(b).

To be sure, the law gives the Commission discretion on certain other issues. That discretion, however, does not extend to the makeup of a utility’s ratebase. For example, the ratemaking statute provides that the “Commission shall consider all other material facts of record that will enable it to determine what are reasonable and just rates.” N.C.G.S. § 62-133(d). That statute, however, “is not a grant to roam at large in an unfenced field.” *State ex rel. Utils. Comm’n v. Pub. Serv. Co.* (*Public Service*), 257 N.C. 233, 237, 125 S.E.2d 457, 460 (1962). In *Public Service*, the Commission engaged in “juggling figures” to arrive at a particular rate of return. (Id. at 236, 125 S.E.2d at 459). In its order, the Commission stated that it had considered “all other facts which we feel have a bearing upon our conclusion—without reference to specific formula.” (Id. at 237, 125 S.E.2d at 460 (emphasis deleted) (quoting Commission order). The Commission was reversed, and the

Court explained that the statutory grant of discretion that is now codified in N.C.G.S. § 62-133(d) does not allow the Commission to depart from the statutory ratemaking formula. To the contrary, when the Court has decided what belongs in a utility's ratebase, it has applied that statutory concept with strict attention to its limits. *See* N.C.G.S. § 62-133(b)(1).

In sum, it is beyond the Commission's authority to allow DEP to receive a return on its coal ash costs, and DEP should not be allowed to profit from current customers for actions taken now to dispose of coal ash that has accumulated for decades and to close ash ponds no longer in use.

F. DEP Has Not Shown That It is Fair to Add a Charge in Future Rates for Coal Ash Costs Associated With Electric Service Provided to Customers.

One of the questions the Commission must answer is whether, when all the material facts in the case are considered, it is fair and legally appropriate to charge current and future customers for coal ash costs associated with waste impoundments that were used to serve past customers over many decades of coal-fired power generation. Fairness is a fundamental consideration when rates are determined. The timing of cost recovery is another basic consideration that must be addressed when rates are determined.

It is not fair to DEP's current and future ratepayers to be burdened by coal ash costs related to past electric service. Fairness was recognized as an important consideration in the Commission's discussion of coal ash cost recovery in the final order in the 2020 Dominion Rate case.[61] Although the Commission did not find that

[61] 2020 Dominion Order at 131.

challengers provided sufficient evidence that specific coal ash costs increased due to imprudent management of Dominion's ash basins,[62] the Commission concluded that it must consider the fairness both to investors and ratepayers of allowing coal ash costs to be recovered in future rates.[63] The Commission observed that, in earlier Commission cases in which utilities have been allowed to recover costs incurred to meet new environmental requirements, or incurred for canceled nuclear units, the full burden was not imposed on customers.[64] Instead, the costs in those cases were allocated between the utility's investors and customers.[65]

Matching was also recognized as an important consideration in the Commission's discussion of coal ash cost recovery in the 2020 Dominion Rate Order. Matching is a basic legal principle in cost of service ratemaking that the same generation of customers who benefit from service should pay for the cost of that service.[66] The Commission recognized that the principle "dictates that customers who use an asset should pay for the asset at the time it is used. Put another way, the costs generated from a resource should be borne by the generation of customers that benefitted from the consumption of the resource."[67]

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[62] The AGO's arguments on the standard applied by the Commission to determine whether costs are reasonable and prudent are addressed in Part I.B.

[63] 2020 Dominion Order at 131.

[64] *Id*. at 130-31 (citing the Final Order in Docket No. G-5, Sub 327 that allowed PSNC to recover prudently incurred manufactured gas plant clean-up costs by spreading out cost recovery over a period of years through amortization without a rate of return); *see also* Order Granting Partial Increase in Rates, *Application of Virginia Electric and Power Company for Authority to Adjust and Increase Its Electric Rates and Charges,* No. E-22, Sub 273 (Dec. 5, 1983).

[65] *Id.*

[66] McDermott, K "Cost of Service Regulation In the Investor-Owned Electric Utility Industry," (Edison Electric Institute (EEI)) (2012) at 6-9 (available at https://www.ourenergypolicy.org/wp-content/uploads/2012/09/COSR_history_final.pdf). (referred to hereafter as McDermott, Cost of Service Regulation). McDermott, Cost of Service Regulation at 9.

[67] 2020 Dominion Order.at 122.

These principles of the fairness and timing of cost recovery are basic considerations that are overlooked in the standard that DEP has proposed for determining what coal ash costs should be recoverable in new rates.[68] But those principles are well established in North Carolina ratemaking statutes and case law.

Based on considerations of fairness and the matching principle, the Commission should either disallow cost recovery for coal ash costs altogether or amortize the costs over a long period of years. The costs relate to CCR that has accumulated over many decades of past service and ash basins that are not any longer used, and cost recovery should be attributed to past rates when the waste accumulated. To the extent recovery is allowed in future rates, the costs should be amortized over a similarly long period so that the burden of the past costs will not fall as heavily on current customers.

1. Fairness and matching are fundamental considerations in ratemaking that must be addressed in the determination.

The Commission's consideration of fairness in the 2020 Dominion Rate Order is well founded on statutory ratemaking provisions. Fairness is the first principle that applies when rates are established: the Commission must fix rates that shall be "fair both to the public utilities and to the consumer." N.C.G.S. § 62-133(a). The statutory formula describes particular requirements for ascertaining the *reasonable* ratebase and *reasonable* operating expenses, and for fixing a *fair*

[68] In its last rate case, DEP argued that it is entitled to recover costs if it has shown that the costs are 1) known and measureable; 2) reasonable and prudent; and 3) used and useful in the provision of service to customers. *See* Post-Hearing Brief of Duke Energy Progress Supporting Recovery of Coal Ash Basin Closure Costs filed 12 January 2018 in Docket No. E-2, Sub 1142, at 7. That limited legal standard is not referenced in appellate cases and fails to take into account all of the elements addressed in N.C.G.S. § 62-133. *See e.g.*, *CUCA*, 348 N.C. at 458, 500 S.E.2d at 698-99.

rate of return. N.C.G.S. § 62-133(b) and (c). Additionally, fairness underlies the requirement to "consider all other material facts of record that will enable it to determine what are reasonable and just rates." N.C.G.S. § 62-133(d).

The Commission's consideration of the matching principle in the 2020 Dominion Rate Order is also well founded on statutory ratemaking provisions. DEP's claim, that it is entitled to cost recovery *as the expenditures are made* for costs of removing long-lived assets, fails to address the matching principle that long-lived assets should be paid for in rates charged *over the life of the assets.*

This principle is incorporated into our ratemaking requirements that use a test year as the starting point for estimating costs and revenues from existing rates. *See* N.C.G.S. § 62-133(c). Adjustments are made to normalize and annualize costs in order to estimate the future cost of service and determine whether there is a need to increase or decrease rates for that purpose. (DEP Tr. vol. 13, 297) DEP's accounting witness[69] testified that "[i]n the state of North Carolina . . . we start with historical actuals [in exhibits showing the costs in a test year]. And then to the extent that those amounts would not be representative of the Company's revenues and expenses in the future, then we are allowed to make certain pro forma adjustments to make them more representative of the future." (Id.) She agreed that expenditures on long-term assets are not recovered in the month that the expenditures are made, but rather are recovered in rates over the useful life of the assets. (Id. at 298-99)

[69] The live testimony and exhibits of DEC accounting witness Jane McManeus provided in the DEC rate case were copied into the record in the DEP case as if given orally from the stand by DEP accounting witness Smith. (DEP Tr. vol. 13, 284)

The matching principle was described by our Supreme Court in *Edmisten* when it stated that "the users in each period should be charged with the cost of service attributable to that period."[70] The Court explained how this works in practice by writing, "[o]f course the full amount of an expenditure for an addition to plant, which will be used in rendering service over a long period of time, is not, and should not be, charged to the customers who use the service in the month of such expenditure, but is spread over the anticipated life of the equipment."[71]

The Commission recognized the significance of the matching principle – and how it has been addressed in DEP's past accounting for the retirement costs associated with long-lived assets – when changes to financial accounting standards were reviewed in 2003.[72] The Commission recognized that the accounting for long-lived assets – including retirement costs of those assets – was at that time being addressed in DEP's established rates by the inclusion of a component for the recovery of closure costs over the life of the assets, not for recovery as expenditures are made at the end of life of the facilities, a method that is consistent with the matching principle. (2003 ARO Order at 11) The Commission recognized in the 2003 ARO Order that a change in that method of accounting might be allowed by future order, but the Commission directed DEP to seek *authority* for a change in accounting *before* implementation. (*Id.* at 11-13)

The direction to DEP that it should seek authority before changing how retirement costs are accounted for in future rates was particularly important

[70] *Edmisten*, 291 N.C. at 470, 232 S.E.2d at 195.
[71] *Id.*
[72] *See* 2003 ARO Order.

because, in North Carolina, rates that have been established by the Commission are deemed to be just and reasonable until they are changed through appropriate procedures. *See* N.C.G.S. §§ 62-132, 62-134. Where particular costs are underestimated in established rates or have not been included, the utility has the opportunity to seek a change in rates, and would be expected to do so if the change in the particular cost or new cost – taken with other rate case factors – means that a rate increase is needed.[73]

The Commission's conclusion in the 2020 Dominion Rate Order applied these fairness and matching principles and reviewed how it has considered the treatment of similarly extraordinary, large costs historically such as when utilities have requested special treatment for environmental remediation costs and plant cancellation costs. 2020 Dominion Order at 132.

Several circumstances in the Dominion case were considered significant:

- Because costs were not found to be imprudent, the Commission concluded that it would be inequitable to place the entire burden on the shareholders, but also concluded that ratepayers should not bear the entire risk and rate impact of the liabilities associated with coal ash. *Id.* at 131.
- Evidence that called into question the prudence of Dominion's actions and inaction and the risks accepted by the management of coal ash sites were weighed. *Id.*

[73] *Edmisten*, 291 N.C. at 468, 232 S.E.2d at 194.

- The magnitude of the total costs at issue were considered regarding the impact on ratepayers as well as shareholders. *Id.*
- The “matching” provision and intergenerational equity concerns were considered given that coal ash cost recovery burdens present and future ratepayers with costs arising from past service. *Id.*

From these facts, the Commission concluded that it should “strike the appropriate balance between shareholder and customer interests to set just and reasonable rates,” 2020 Dominion Rate Order at 132 (citing N.C.G.S. § 62-133(d)), and accordingly, Dominion’s shareholders should bear some of the risk of the obligations to clean up CCR and close basins.

2. Coal ash costs that DEP seeks to recover in this case present issues of fairness and timing that must be weighed in the decision about how the costs will be accounted for.

The Commission must weigh fairness both to the utility and customers and must consider the appropriateness of cost recovery in future rates, taking into account other material facts of record that will enable it to determine what are reasonable and just rates. The following are similar factors to those identified in the Dominion case:

- To the extent that costs are not found to be imprudent, the Commission might conclude that it would be inequitable to place the entire burden on DEP’s shareholders, but also conclude that ratepayers should not bear the entire risk and rate impact of the coal ash liabilities.
- Extensive record evidence is provided in Part I.A that demonstrates DEP’s negligent actions and inactions and the risks accepted by those managing DEP’s coal ash ponds, and will not be repeated here.

- Further, a substantial portion of the costs now being incurred are for the closure of ash basins that have not been in use for decades, but were not properly closed, as discussed in Part I.C.

- The magnitude of the total costs during the deferral period is significant and DEP's proposal imposes a large charge on ratepayers. The revenue requirement in this case is increased $111 million for the coal ash costs deferred from 1 September 2017 through 29 February 2020 under DEP's proposal. (DEP Tr. vol. 13, 327-28) That is in addition to the roughly $53 million per year already reflected in the revenue requirement. (Id.) Together, over $160 million is reflected in the annual revenue requirement for North Carolina retail customers. (Id. at 328) While the costs will not be allocated on a per-customer basis, roughly speaking the impact would be about $118-120 per customer per year. (Id. at 328-29)

- The imposition of these costs of past service on current and future ratepayers is an unfair mismatching of costs to the rates charged, and poses intergenerational equity concerns similar to those in the Dominion case.

Additional facts in this case show why it is unfair and unreasonable to impose these past costs on current and future ratepayers.

DEP was not only negligent in how it operated the coal ash ponds with little regard for environmental compliance standards, but it was also negligent in how it addressed regulatory requirements for cost recovery of the retirement costs associated with the coal ash basins. As discussed earlier, the Commission issued an order in 2003 that addressed how regulatory accounting would be affected by new financial accounting requirements regarding legal AROs. (2003 ARO Order) In that Order it was acknowledged that DEP had nonlegal asset retirement obligations, including obligations for costs of removal of nonnuclear (e.g., coal) generating facilities, which were being accounted for through Commission-approved depreciation rates. (2003 ARO Order at 7, 11-13) The Order did not mention coal ash basins specifically either to indicate that they were considered part of the coal generating facilities or to create an exception for accounting purposes as to how the retirement costs would be addressed. DEP was directed to continue to accrue cost of removal obligations associated with nonlegal AROs through depreciation rates as prescribed in its most recent rate case. Such costs of removal were to be accounted for over the life of the related assets, *rather than waiting to record the expense until the assets would actually be removed and the related cost actually paid*. (2003 ARO at 11, 13) The Commission's accounting for such costs through depreciation expense matches the timing of cost recovery to the time when ratepayers benefit from the assets.

DEP has collected an increment in rates in depreciation expense for the recovery of retirement costs – including coal ash basin closure costs – over the useful lives of the facilities:

- A specific increment was collected in the removal portion of depreciation rates in DEP's 2012 general rate case based on 2012 dismantlement studies, for recovery of the closure of CCR basins costs in advance of when closure expenditures began (*i.e.*, over the life of the facilities, as indicated in the 2003 Order.)[74] The increment was based on two Burns & McDonnell decommissioning studies dated 27 January 2012, that specifically addressed closure of ash ponds. (DEP Tr. vol. 16, 309)
- Prior to the 2012 general rate case, decommissioning costs for coal ash basins were reflected in the Company's depreciation study, but not in a specific dollar amount. (DEP Tr. Vol. 16; 309 DEC/DEP Late-Filed

[74] DEP 2018 Order at 141.

Exhibit 18, 18) John J. Spanos,[75] DEP's expert witness on depreciation, testified that a depreciation study for DEP's predecessor dated 31 December 2002 "reflects a calculated net salvage percentage for equipment and facilities . . . which would include coal ash basins as part of the plant facilities, although not in any specific dollar amount." (DEP Tr. vol. 17, 35-36) He explained that the decommissioning costs were much less precise than the costs now applied for basin closure. (Id. at 37)

Furthermore, the record shows that DEP knew – or should have known – from industry publications and internal reports that the costs would be significant to close the ash ponds but did not begin to close basins that were no longer in use and underestimated the closure costs:

- Internal documents for DEP show that the cost to close ash basins was expected to be substantial. (Hart Exhibit 25; DEP Late-Filed Exhibit 19; DEP Late-Filed Exhibit 21)
- A report published by the Electric Power Research Institute in 2004 predicted that the cost of addressing coal ash would be the biggest cost associated with closing coal plants. (Doss/Spanos/Riley Rebuttal AGO Cross Exhibit 1 at 2-5; DEP Vol. 17, 33)[76]

[75] Mr. Spanos is an associate with Gannett Fleming Valuation and Rate Consultants, LLC, has over 30 years of depreciation experience, and has provided expert testimony in over 300 utilities cases.

[76] The exhibit, an EPRI document titled "Decommissioning handbook for Coal-Fired Power Plants" dated November 2004, states at 2-5, "Closure of surface impoundments and landfills probably will be the most expensive tasks undertaken during a Decommissioning process."

- The lower-end cost estimates identified in studies were based on the cost estimated to close ponds by using "cap in place," without a need to remove ash from basins, (DEC/DEP Late-Filed Exhibit 20 at 20, 61) and did not include ash in lay of land disposal areas. (DEC/DEP Late-FiledExhibit 18, 11, 18)
- But EPRI industry research results published by EPRI in 2001 concluded that dewatering and cap in place would not improve, and might worsen, groundwater pollution at basins where a portion of the ash is below the water table.[77] (DEP Late-Filed Exhibit 10)
- Since DEP constructed its basins in at-risk ecological areas, it should have known that a cap over the basins would not address groundwater requirements, and likely more costly measures would be needed. (Hart Exhibit 15)

On the other hand, DEP seeks cost recovery because the costs to close the ash basins and dispose of CCR are for extraordinary costs that are large in magnitude, and are required by recent environmental regulations. (McManeus/Speros AGO Cross Examination Exhibit 1)

These facts show that DEP continued to account for the costs to retire its ash basins by including an increment in rates to recover the costs over the life of the coal plants, but negligently underestimated coal ash closure costs in past proceedings because it postponed the actual closure of the basins after they were no longer in use, and pushed of tasks as well as costs for generations..

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[77] *Evaluation and Modeling of Cap Alternatives at Three Unlined Coal Ash Impoundments,* EPRI, Palo Alto, CA: 2001. 1005165.

Because DEP's underestimates and negligent inaction caused the coal ash costs requested in this case to be much larger, it is unfair to shift those costs of past service onto a new generation of ratepayers. Electric service today is not provided by use of the coal ash facilities. As the Commission explained in the Dominion Order, the matching principle is violated by DEP's recovery of these past costs from future customers. (2020 Dominion Order at 122) DEP's claim that it is entitled to cost recovery *as the expenditures are made* for costs of removing long-lived assets, fails to address the legal ramifications of DEP's long-time accounting for such assets *over the life of the assets.*

DEP did not seek a change in how the accounting for coal ash would be addressed until after it recognized a large legal asset retirement obligation in financial records associated with the costs. (AGO McManeus/Speros Cross Examination Exhibit 1) Accordingly, the matching principle is relevant to the determination of the costs that are recoverable from future ratepayers.

3. Based on these basic issues of fairness and principles of timing that apply to ratemaking, DEP's coal ash costs should not be recovered in future rates, and if allowed to some extent, the costs should be amortized over a long period.

These facts should be weighed when the Commission considers the fair allocation of the coal ash costs between future ratepayers and DEP's investors, and DEP's request for cost recovery should be denied.

The balance that the Commission struck in the 2020 Dominion Rate Order amortized the coal ash costs in operating expenses over ten years without allowing a recovery of a return on the unamortized balance,[78] which is fairer to consumers than what DEP proposes in this case (*i.e.*, five year amortization plus rate of return) but still puts a large share of the costs on consumers.

Amortizing the costs that are allowed will not match them up to the users who benefitted from the electricity generated when the coal ash waste was produced, but if a long amortization period is used, the burden of the costs for current and future customers will be spread out so that it does not fall as heavily on current users. A long amortization period is also more consistent with the length of time over which the waste has accumulated. More burden would fall on shareholders due to the longer time before the expenditures are recouped in rates but that is justified by the long history of neglect and delays in how DEP has managed the facilities.

DEP's proposal, by comparison, includes full recovery over a short five-year amortization period plus a rate of return that DEP proposes to add, as if the coal ash costs are an investment in an asset that will be used for delivering or generating electricity now or in the future. The issue whether the Commission may allow a rate of return is addressed in Part I.E, but the issue is also a problem in terms of fairness. Commissioner Clodfelter predicted in Duke Carolinas' last rate case that allowing a rate of return converts the "relief" sought in the initial Petition into "a new opportunity for capital investment and for profit-making" in the eyes of investors.[79] DEP witness Newlin confirmed this view when he testified that

[78] Whether the Commission has discretion to apply or not to apply a rate of return to coal ash costs during deferral and amortization is addressed in Part I.E.
[79] 2018 DEC Order Clodfelter Dissent at 45

investors see the coal ash costs as an investment and expect a return. (DEC/DEP Consolidated Tr. Vol. 2, 34-35) That is a troubling outcome for what began with a spill on the Dan River caused by neglect, admissions of criminal negligence in the operation of DEP ash basins as well as DEC basins, disclosures of contamination problems at all of DEP's plants, and now the request for rate relief from high costs as closure expenditures are made – years after DEP knew that the costs would be very substantial.

The alternative suggestion that DEP's costs might be allowed as an increment in new rates based on the estimated annual expenditures for coal ash basin closure – similar to the "run rate" that was proposed by DEP in the last case and rejected by the Commission – would not be any fairer to consumers, and would violate the matching principle described by the Court in *Edmisten* by imposing the full burden of an expenditure for a long-lived asset on the rates in the month spent rather than over the life of the asset.[80]

II. DEP'S SETTLEMENT PROPOSAL, WHICH WOULD FIX AN UNJUSTIFIABLY HIGH 9.6% RATE OF RETURN ON EQUITY AND 52% EQUITY CAPITAL STRUCTURE, ADDS OVER $48 MILLION ANNUALLY TO THE REVENUE REQUIREMENT AT A TIME WHEN RATEPAYERS ARE STRUGGLING TO SURVIVE ADVERSE ECONOMIC CONDIITONS BROUGHT ON BY THE PANDEMIC.

In these challenging economic times, it is particularly important for the Commission to set DEP's rate of return based on evidence that is well supported by current market indicators. DEP has not met its burden of proof that the 9.6% ROE and the 52% equity capital structure proposed in the partial settlement[81] are

[80] *Edmisten*, 291 N.C. at 468-69, 232 S.E.2d at 194; *see* McDermott, Cost of Service Regulation at 9.
[81] 31 July 2020 DEP-Public Staff Stipulation at 10.

required in order for DEP to attract the investment dollars needed for adequate service. Nor has DEP shown that the proposed return is otherwise advantageous or fair for North Carolina retail customers. The AGO suggests that the Commission adopt an ROE of 9.0% and a 51.5% equity capital structure. Financial market data show that a 9.0% return on equity is sufficient, and the lower return fairly balances the interests of investors and consumers. This is demonstrated in expert testimonies of AGO witness Richard A. Baudino,[82] Public Staff witness J. Randall Woolridge,[83] and CUCA witness Kevin W. O'Donnell.[84] *See* Table 1 below. The sufficiency of a 51.5% equity to 48.5% debt capital structure is well supported by evidence; indeed, that is lower than the average common equity ratio maintained during the test year for comparable companies studied in the proxy group used by DEP's expert witness. (DEP Tr. vol. 13, 483) This capital structure is also less costly and fairer to consumers. The rate of return factors that DEP proposes in the Partial Settlement would unnecessarily add over $48 million to DEP's annual revenue requirement.[85] (DEC/DEP Consolidated Tr. vol. 2, 132) It is time to reduce

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[82] Witness Baudino is Director of Consulting and Consultant with Kennedy and Associates and has thirty-seven years of experience in ratemaking for regulated electric, gas, and water utilities, and presents expert testimony in cost of capital and rate of return. He has a Master of Arts in Economics with a minor in Statistics. (DEP Tr. vol. 13, 443-44).

[83] Witness Woolridge is a Professor of Finance and the Goldman, Sacks & Co. and Frank P. Smeal Endowed University Fellow in Business Administration at Pennsylvania State University, and has prepared testimony and provided consulting service for over 25 years on rate of return in regulatory cases. (DEP Tr. vol. 15, 525, 671)

[84] Witness O'Donnell is President of Nova Energy Consultants, Inc., has worked as a financial analyst in utility regulation for over 35 years, beginning with the Public Staf, and has presented expert testimony on rate of return, cost of capital, and in other areas of ratemaking. He has a Master of Business Administration and is a Chartered Financial Analyst. (DEP Tr. vol. 14, 130-31)

[85] Establishing a 9.0% rate of return on equity (ROE) is supported by stock market data showing what investors require under current economic conditions and a 51.5% equity ratio in the Company's capital structure is sufficiently conservative.

DEP's rate of return to the lower level supported by market data, particularly given the dire economic conditions many customers face.

Furthermore, if — as DEP requests in its rate application — the Commission determines it has discretion to allow coal ash cost recovery from future customers, the Commission should also exercise discretion for the benefit of consumers on this issue when it considers the range and midpoint of reliable equity cost studies and financial indicators. The Commission should establish a substantial reduction in the rate of return.

A. DEP's Return on Equity Must be Based on Current Economic Conditions Affecting Investors and Consumers, Should be Fair to Both, and Should Not be Based on Improper Considerations.

Under North Carolina's statutory formula, the Commission must look to current market conditions when setting the rate of return and evaluate what is necessary for DEP to attract capital. Section 62-133 specifies that the Commission shall fix the rate of return to produce a fair return for shareholders "considering *changing economic conditions*."[86] Under the statute, the rate of return should allow the utility to "compete in the market for capital funds" on reasonable terms.[87] The statute cautions that those terms must be fair not only to the utility's existing investors, but also to its customers,[88] and the Commission must take into account the interests of customers when it fixes the return on equity.[89] In the words of our state's Supreme Court, the rate of return provision "advances the Legislature's twin

[86] N.C. Gen. Stat. § 62-133(b)(4) (emphasis added). *State ex rel. Utils. Comm'n v. Cooper* (*Cooper 2)*, 367 N.C. 430, 440, 758 S.E.2d 635, 641 (2014) (internal quotation marks and citation omitted).
[87] *Id.*
[88] *Id.*
[89] *Cooper 2*, 367 N.C. at 440, 758 S.E.2d at 641 (internal quotation marks and citation omitted).

goals of assuring sufficient shareholder investment in utilities while simultaneously maintaining the lowest possible cost to the using public for quality service."[90]

DEP's capital structure includes both long term debt and common equity.[91] Determining the rate of return on debt is generally straightforward, but the return on common equity (ROE) is more difficult to determine.[92] The Commission's determination of the appropriate ROE is extremely important, because it is the most expensive form of capital and the cost is paid by ratepayers.[93] As such, the statutory provisions relating to ROE "cannot be read in isolation as only protecting public utilities and their shareholders. Instead, it is clear that the Commission must take customer interests into account when making an ROE determination."[94]

The test laid down in N.C.G.S. § 62-133(b)(4) for determining a rate of return that is fair to investors and ratepayers is whether the rate is "sufficient to enable the utility to attract, on reasonable terms, capital necessary to enable it to render adequate service."[95] The determination must take into consideration changing economic conditions and other factors as they then exist.[96] Early United States Supreme Court cases established guiding principles which the General Assembly subsequently incorporated into the North Carolina ratemaking statute,[97] holding that the rate of return is one "which will enable the utility "by sound

[90] *Id.* at 440, 758 S.E.2d at 641 (internal quotation marks and citation omitted).
[91] Smith Exhibit 1 Second Settlement p 2.
[92] *Public Staff*, 322 N.C. at 697-98, 370 S.E.2d at 572-73.
[93] *Id.*
[94] *State ex rel. Utilities Comm'n v. Cooper* (*Cooper*), 366 N.C. 484, 495, 739 S.E.2d 541, 548 (2013).
[95] *Duke Power,* 285 N.C. at 393, 206 S.E.2d at 280.
[96] N.C.G.S. § 62-133 (a)(4); *State ex rel. Utilities Comm'n v. Public Staff* (*Public Staff 2*), 331 N.C. 215, 221, 415 S.E.2d 354, 359 (1992).
[97] *See Duke Power*, 285 N.C. at 388, 393, 206 S.E.2d at 276-77, 280; *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virgini*a, 262 U.S. 679 (1923); *Federal Power Commission v. Hope Natural Gas Co*., 320 U.S. 591 (1944).

management": (1) to produce a fair profit for its stockholders, in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the market for capital."[98] Economists generally interpret the standard to mean that a fair rate of return on equity for regulated utilities should be based on the comparable returns investors expect to earn from other firms with similar risk, and should be sufficient for the firm to attract capital. (DEP Tr. vol. 11, 260; DEP Tr. vol. 13, 447-48; DEP Tr. vol. 15, 527)

Our appellate courts have concluded that some factors are *not* appropriate considerations for the Commission when it determines a utility's rate of return, and the Commission should reject arguments that would rely on these improper factors.

1. Certain factors are entitled to no weight or limited weight.

a. The Commission should reject arguments that rely on other utilities' and regulators' authorized returns.

DEP and other parties tend to compare the ROE proposed in this case to the ROEs or the averages of ROEs that have been authorized for utilities by regulatory commissions in other cases, (DEP Tr. vol. 11, 279-80, 342-43, 405, 443, 474, 621-25; DEP Tr. vol. 15, 572, 695), but our Supreme Court has concluded that it is not proper to give weight to such other returns determined in regulatory proceedings, since the details underlying those determinations are not of record.[99] For example, in 1992, the Supreme Court overturned this Commission's order regarding the ROE fixed for Duke Power in part because the Commission gave

[98] *State ex rel. Utilities Comm'n v. General Tel. Co.*, 281 N.C. 318, 370, 189 S.E.2d 705, 738 (1972).
[99] *Public Staff 2,* 331 N.C. at 224-25, 415 S.E.2d at 360-61; *see also Cooper 2*, 367 N.C. at 443, 758 S.E.2d at 643.

weight to ROE decisions by other regulatory authorities.[100] The Court found that the decisions by other regulatory authorities "fail[ed] to support the Commission's findings because there is nothing in the record to show that the equity return requirement for any of these utilities is comparable to Duke's."[101] Similarly, in 2014, the Court reversed and remanded an order of this Commission on ROE and concluded that "the Commission's reliance on past ROE determinations authorized for other utilities, without evidence tying those determinations to the facts of the case *sub judice*, prevented the Commission from fairly considering current economic conditions."[102]

Contrary to the holdings in these Supreme Court's decisions, DEP's expert encourages the Commission to rely heavily on the results reached for other utilities by other regulators in other cases. (DEP Tr. vol. 11, 279-80, 342-43) Indeed, DEP witness Dylan W. D'Ascendis[103] incorporated authorized returns as a key factor for his Bond Yield Plus Risk Premium model. (DEP Tr. Vol. 11, 342-43) His method in that study compares long-term (30-year) bond yields to regulators' determinations of *authorized* rates of return. Some of the rates of return in his study were authorized as long ago as 1980, and he uses this data for his model in lieu of market data about current market conditions. (Exhibit DWD-5 p 2; Rebuttal Exhibit DWD-5 at 2; Supplemental Rebuttal Exhibit DWD-5 at 2) As such, witness

[100] *Public Staff 2,* 331 N.C. at 225, 415 S.E.2d at 361.
[101] *Id.*
[102] *Cooper 2*, 367 N.C. at 443, 758 S.E.2d at 643.
[103] Testimony initially filed by Robert Hevert was adopted by witness D'Ascendis. (DEP/DEP Consolidated Tr. vol. 1, 116). Witness D'Ascendis is a Director at ScottMadden, Inc. He has provided expert testimony in electric utility proceedings since 2016 and in water utility proceedings for almost nine years. He holds a Masters of Business Administration and has certifications as a Rate of Return Analyst and Valuation Analyst. (DEP Tr. vol. 11, 249-50)

D'Ascendis' Bond Yield Risk Premium analysis measures not "the market for capital funds" – the test under N.C. Gen. Stat. § 62-133(b)(4) – but instead the behavior of *regulatory commissions* over time. (DEP Tr. vol. 13, 504; DEP Tr. vol. 15, 656) Historical commission-allowed ROEs provide only an imprecise measure of investor preference and market conditions, and the model used in witness D'Ascendis' analysis produces exaggerated results due to this flaw and others.[104] (DEP Tr. vol. 13, 504-05)

Therefore, as a matter of law, the Commission should disregard witness D'Ascendis' Bond Yield Risk Premium analysis. Further, it should not give weight to evidence of the ROEs authorized by regulatory agencies in other cases.

b. The Commission should reject arguments that rely on gradualism.

Similarly, it is improper to reject evidence on the ground that the evidence supports a return that is substantially lower than what was authorized in the company's prior general rate case. Our Supreme Court has held that the Commission's concern about an "extreme fluctuation" between the rate of return allowed in a pending general rate case compared to the previous case is an improper consideration that "has nothing to do with the [c]ompany's existing cost of equity."[105] Efforts that arise from a desire to protect investors from swings in market prices are inappropriate.[106] Further, any concern that changes to the company's return should only be gradual is inconsistent with N.C. Gen. Stat. § 62-

[104] Witness D'Ascendis' analysis is also erroneous because it relies on projected bond yields, as well as current yields, driving the results up. (DEP Tr. Vol. 13, 501, 503; DEP Tr. Vol. 15, 655)
[105] *Cooper 2*, 367 N.C. at 442-43, 758 S.E.2d at 642-43 (quoting *Public Staff 2,* 331 N.C. at 225, 415 S.E.2d at 361).
[106] *Public Staff 2,* 331 N.C. at 225, 415 S.E.2d at 361.

133(e), which specifies that "[t]he fixing of a rate of return shall not bar the fixing of a different rate of return in a subsequent proceeding."[107]

In this case, the fact that the partial settlement reduces the ROE by 30 basis points from the last rate case is a step in the right direction, but does not mean that the partial settlement is reasonable and fair where the evidence supports a more substantial reduction. (DEC/DEP Consol. Tr. vol. 2, 132-33)

c. The existence of a partial settlement is entitled to only limited weight.

The Commission is urged to approve a 9.6% ROE because it has been accepted by some parties as one piece of a settlement of most issues in the case. (DEP Tr. Vol. 11, 620; DEP Tr. vol. 15, 691-92) The Commission may consider the settlement along with all of the evidence, but it would be improper and unfair to authorize an excessive ROE settled upon by some parties in exchange for concessions by DEP as to other elements of the case. The North Carolina statute that addresses how rates are fixed describes a formula to follow, and the statute expressly requires the Commission to *fix* the rate of return. N.C. Gen. Stat. § 62-133(b)(4). As such, when the Commission considers proposals put forth as part of a non-unanimous stipulation, it must "make its own independent conclusion supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented."[108] In its determination of a fair ROE, in particular, the Commission should consider and

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[107] N.C.G.S. § 62-133(e).

[108] *See CUCA*, 348 N.C. at 466, 500 S.E.2d at 703 (reversing Commission order fixing ROE because it was adopted from the partial stipulation without Commission consideration and analysis of all the evidence regarding proper rate of return and without an independent conclusion adduced from the evidence).

analyze a stipulated ROE "along with all the evidence regarding proper rate of return" and adduce "its own independent conclusion as to the proper rate of return on equity."[109]

2. A 9.0% return on equity is supported by market indicators and analyses showing the return investors require under current economic conditions, as is evidenced in the testimonies from expert witnesses Baudino, Woolridge and O'Donnell.

Taking into account all of the evidence in the record, there is substantial support for the Commission to fix a 9.0% return on equity based on current market conditions. Financial indicators, including the current yields on long-term Treasuries and the average yields on long-term utility debt, are evidence that the cost of capital is very low and has dropped significantly in the past year despite the economic impact of the COVID-19 pandemic. The Discounted Cash Flow (DCF) studies performed by all four experts produce results that support an average cost of equity *less than* 9.0%, even taking into account the economic impact of the pandemic. The DCF method is widely used by investors, is the method considered by experts in this case to be the most reliable, and was historically the method favored by this Commission.

The COVID pandemic and ensuing economic downturn increased financial market volatility for a time, but market data and reports have continued to indicate that regulated electric utilities like DEP are safe, conservative, and relatively stable investments. (DEP Tr. vol. 13, 511-21) Indeed, the impact of COVID on the required rate of return was addressed in supplemental testimony filed by two of the

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[109] *Id.* at 466-67, 500 S.E.2d at 703.

witnesses – AGO witness Baudino and Company witness D'Ascendis – and neither changed his recommended ROE. (DEP Tr. vol. 11, 615; DEP Tr. vol. 13, 523)

a. Current market forces demonstrate that an ROE substantially lower than 9.6% will provide a sufficient return for the Company to compete for capital in current markets.

Financial markets indicators show that the cost of capital is very low under current economic conditions.

The comparative risk of investment opportunities is a key influence on investors, and the cost of equity for regulated utilities is sensitive to changes in interest rates. (DEP Tr. vol. 13, 445-46, 448-59, 479, 512; DEP Tr. vol. 15, 555-57) Value Line reported in February 2020 that cuts in interest rates by the Federal Reserve in 2019 reduced interest rates on already low fixed income investments, and heightened the appeal of dividend yield paying electric utility equities. (DEP Tr. vol. 13, 456-57)

The overall trend in interest rates has been downward since 2007-2008 when the Federal Reserve used "Quantitative Easing" to foster improved financial market conditions, cutting the federal rate and effectively lowering the long-term cost of borrowing. (DEP Tr. vol. 13, 449-54) Even when the Federal Reserve pared back its Quantitative Easing policy and raised the funds rates, the 30-Year yield remained low. (DEP Tr. vol. 15, 543-44) In 2019, the Federal Reserve reversed course and cut rates again. (DEP Tr. vol. 13, 452; DEP Tr. vol. 15, 621) In February 2020 just prior to the outbreak of the pandemic, the yield was 1.97%. (DEP Tr. vol. 13, 451) The yield rose for a time in March as markets responded to the pandemic but soon went back down, and by the end of June 2020 the yield was even lower than in February, at 1.41%. (DEP Tr. Vol. 13, 512)

The yield on the average public utility bond has also been low and trending downward. The average yield was 3.34% in January, rose to 4.24% in mid-March as the effect of COVID was felt in financial markets, but dropped back again by the end of March and was 3.05% by the end of June, lower than the average yield in January before the start of the pandemic. (DEP Tr. vol. 13, 512)

DEP's cost of debt has dropped. Company witness Karl W. Newlin testified that a recent debt issuance for DEP had a 2.5% coupon rate for a 30-year term, substantially lower than DEP's embedded cost of debt, which is 4.11%. (DEC/DEP Consolidated Tr. vol. 1, 64, 76-66)

Equity investors are also influenced by credit ratings, and DEP's credit ratings are high.

- DEP has an A2 rating from Moody's and an A- rating from Standard and Poor's (S&P's) with stable outlooks. (DEP Tr. vol. 13, 517)
- DEP is above average. The industry average was BBB+ for S&P according to the Edison Electric Institute (EEI) report for the 3rd quarter of 2019. (DEP Tr. vol. 13, 458) Most had credit ratings of BBB/BBB+, and only about ¼ had a credit rating of A-.
- DEP's relatively high credit ratings indicate that it is not relatively more risky than the other electric utilities used in the proxy group, and these ratings do not support the Company's contention that DEP's cost of

equity should be higher than that of the proxy group. (DEP Tr. vol. 13, 508-09; DEP Tr. vol. 15, 622)

- DEP's ratings did not change between February and late June when the impact of COVID was analyzed in supplemental testimony. (DEP Tr. vol. 11, 612; DEP Tr. vol. 13, 516-17)

Some measures of market uncertainty and risk since the pandemic indicate that risk has increased under current economic conditions. The Volatility Index (VIX) reflected a significant increase in expectations of volatility in March when the market impact of COVID was at its peak. Recently, the index has been higher than it was in February, but has stabilized at levels below the spike in March. (DEP Tr. vol. 13, 513) The average beta for electric utility stocks rose substantially, also indicating increased riskiness. (DEP Tr. vol. 13, 518-21) (Beta is a measure of the riskiness of particular stocks relative to the overall riskiness of equities.) (DEP Tr. vol. 13, 513)) However the reliability of the beta factor has been questioned both by Company witness D'Ascendis (DEP Tr. vol. 11, 337-41) and by AGO witness Baudino (DEP Tr. vol. 13, 471-72, 520-21), and the large increase in beta estimates of riskiness for utilities do not line up with other financial indicators including the decline in average utility bond yields during the period. (DEP Tr. vol. 13, 520-21) Significantly, neither of the experts who provided supplemental testimony modified his recommendations about the ROE as a result of the market changes relating to COVID. (DEP Tr. vol. 11, 615; DEP Tr. vol. 13, 511)

b. Financial models indicate that 9% is a sufficient ROE.

All of the expert economic witnesses used at least two well established models to estimate the cost of equity, and Table I below shows the range of results of those studies as well midpoints of the ranges.

TABLE 1

Witness	Party	ROE	Note	DCF Range	DCF Midpoint	CAPM Range	CAPM Midpoint
Partlial Settlement		9.60%					
D'Ascendis	DEC	10.50%	1	7.76% - 9.67%	8.72%	10.19% - 15.70%	12.95%
Baudino	AGO	9.00%	2	8.29% - 9.28%	8.79%	6.19% - 9.61%	7.90%
O'Donnell	CUCA	8.75%	3	7.0% - 10.0%	8.50%	5.0% - 7.0%	6.00%
Woolridge	Public Staff	9.00%	4	8.15% - 8.4%	8.28%	6.70%	6.70%

Note 1 See D'Asccendis Supplemental Rebuttal, Tr. Vol. 11, 595-96, Table 1 pre-filed 7/20/2020.

Note 2 See Baudino Supplemental, Tr. Vol. 13, 518, Table 1, pre-filed 7/10/2020.

Note 3 See O''Donnell Updated, Tr. Vol. 14, 229, Table 8.

Note 4 See Woolridge, Tr. Vol. 15, 616, Table 7, 617.

These results for all four witnesses show that the Discounted Cash Flow (DCF) model supports an ROE recommendation of under 9%, and the results for three of the four witnesses show that the Capital Asset Pricing Model (CAPM) supports an even lower ROE recommendation, albeit with a wider range of results. Witness D'Ascendis' CAPM study indicates much higher results, but his study is flawed and upwardly biased, as described below. (DEP Tr. vol. 13, 499-501; DEP Tr. vol. 15, 623, 627, 630, 633-53; DEP Tr. vol. 14, 186-88)

DCF Analyses

A constant growth DCF analysis values a financial asset based on its ability to generate future net cash flows. (DEP Tr. vol. 13, 464) The cost of common equity is measured based on the sum of the dividend yield plus the expected rate of growth of dividends for comparable companies.[110] (DEP Tr. vol. 13, 464) The DCF approach was considered the most reliable method for measuring the cost of equity by witnesses Baudino, Woolridge, and O'Donnell. (DEP Tr. vol. 13, 444-45, 463; DEP Tr. vol. 15, 556-82; DEP Tr. vol. 14, 204) The method is commonly relied on by cost of capital witnesses and is used in some form by virtually all investment firms as a technique for valuation. (DEP Tr. vol. 15, 584; DEP Tr. vol. 14, 204-06) The model uses current stock prices that are verifiable and publicly available, offering the best indicator available of what investors require. (DEP Tr. vol. 13, 466, 493; DEP Tr. vol. 14, 204) Analyst projections of earnings and dividend growth and historical measures of growth are also readily available. (DEP Tr. vol. 13, 493; DEP Tr. vol. 15, 590) It is reasonable to focus on the midpoint of the results because it is safe to assume that investors would use average results – not the highest or lowest results – to estimate the rate of return. (DEP Tr. vol. 13, 494) Of the four experts who performed DCF studies, witness Baudino's average result estimates a rate of return of 8.79%, the highest average produced by the four experts. (*See* Table 1.)

Company witness D'Ascendis did not give weight to his DCF results, and suggests that the DCF model underestimates the return required by equity investors under current market conditions, but his reasoning is not sound. He criticizes the assumption that growth is constant over time and notes that the results may be affected by monetary policies. (DEP Tr. vol. 11, 402-04; DEP Tr.

[110] *See State ex rel. Utilities Com. v. Public Staff,* 323 N.C. 481, 488, 374 S.E.2d 361, 365 (1988).

vol. 13, 44-97) However, as witness Baudino explained, it is reasonable to assume that markets are efficient and that investors have already taken into account that there are variations in growth. That the price-to-earnings ratio is higher now than it has been on average is widely known. Fed policies are publicly available. All models make assumptions that cannot be realized 100% of the time. (DEP Tr. vol. 13, 494-97)

The DCF model was considered to be more reliable than the CAPM by most of the experts, and in past years this Commission also gave the DCF model the most weight. The reason for not relying on the DCF more recently appears to be due to the fact that the DCF supports a larger reduction to the ROE, which is not an appropriate consideration.

CAPM Analyses

The capital asset pricing model is a risk premium analysis that measures the cost of equity by summing the yield on a risk-free bond plus an appropriate risk premium. (DEP Tr. vol. 13, 470) This model was given less weight by witnesses Baudino, Woolridge and O'Donnell – even though it produced a lower ROE result than other models – because they have found the DCF model is more reliable for estimating the cost of equity for public utilities. (DEP Tr. vol. 13, 444-45, 463; DEP Tr. vol. 15, 582, 616; DEP Tr. vol. 14, 204)

Witness Baudino explained his concerns about the assumptions relied on in the CAPM. One of the factors used in the model is an estimate of the return on equity required in the overall market. That factor requires considerable judgment and may produce wide-ranging results. (DEP Tr. vol. 13, 472-73) Baudino pointed out the much higher results produced by witness D'Ascendis. Baudino also observed that there is controversy about whether the beta factor is a sound measure of the riskiness of particular stocks. (DEP Tr. vol. 13, 471-72) Witness D'Ascendis also expressed doubts about the CAPM due to concerns regarding the reliability of the "beta" factor to measure riskiness. (DEP Tr. vol. 11, 337-41) D'Ascendis was concerned in cases where the beta estimates a significantly reduced risk that results in substantially lower ROE results. (Id.)

Flaws in the methods used in witness D'Ascendis' CAPM distorted his results. For one thing, he used two measures of the risk-free rate, one the current 30-day yield, and the other, a near-term projected yield. (DEP Tr. vol. 13, 500) It is not reasonable to use a projected yield and its use inappropriately inflates the results. Instead, current yields are appropriate measures of the risk free rate; current yields embody the market data and expectations of investors and provide verifiable market evidence. (Id.) Another problem is that witness D'Ascendis' estimates of the overall market return are excessive, driving his results upward. (DEP Tr. vol. 13, 500-01) His ECAPM study - which was used to adjust the effect of the beta factor downward - further increased his results in his earlier study. (DEP Tr. vol. 13, 502-03)

The limited predictive value of the CAPM was evident when the beta factor for utilities increased significantly after COVID, driving up the CAPM results. This steep increase in CAPM results, however, was not reflected in a change in stock prices (which are a more transparent measure of investor response). Nor was it consistent with other indicators such as the yields on Treasuries and on utility bonds. (DEP Tr. vol. 13, 520-21)

Other Studies

Other studies performed by witnesses D'Ascendis and O'Donnell should not be given much weight by the Commission, as they either rely on upwardly-biased data, or on factors forbidden by our Supreme Court, or the expert who performed the study did not support relying on it other than as a check to another method.

Witness D'Ascendis performed another risk premium analysis that he called the Bond Yield Plus Risk Premium, and it has two flaws. (DEP Tr. vol. 11, 342-46) First, his use of projected interest rates caused the results of the study to be higher and prompts concerns about the results, for reasons discussed above in connection with the CAPM study. (DEP Tr. vol. 13, 500) Second, his use of regulators' *authorized* returns in lieu of basing his analysis on current market data is not permissible in fixing ROEs in North Carolina, as was discussed in Part II.A.[111] (DEP Tr. vol. 13, 503-04) Thus, the study relies on improper factors.

Neither should witness D'Ascendis' Expected Earnings approach be given any weight. As the Commission observed in its recent rate case order for Piedmont Natural Gas, there are two problems with the analysis.[112] First, it uses projected earnings for years well beyond the date rates will be effective in this case; *i.e.*, the

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[111] *See* Part II.A; *Public Staff 2,* 331 N.C.at 224, 415 S.E.2d at 360-61; *see also Cooper 2,* 367 N.C. at 443, 758 S.E.2d at 643.

[112] Order Approving Stipulation, Granting Partial Rate Increase, Line 434 Revenue Rider, EDIT Riders, Provisional Revenue Rider, and Requiring Customer Notice issued 31 October 2019 in Docket No. G-9, Sub 743 at 43.The analysis was used by witness Robert Hevert in the Piedmont case, and, as was noted earlier, the similar testimony in this case was originally prepared by Mr. Hevert and later adopted and presented by witness D'Ascendis.

years 2022-2024. (DEP Tr. vol. 11, 346-47; DEP Tr. vol. 13, 505-06)[113] Second, the Commission has previously stated that it does not favor future projections based solely on analysts' earnings projections.[114]

In addition, the Expected Earnings approach relies on projected earnings on book value of investment for each of the companies in the proxy group as a basis for estimating the cost of capital. The analysis does not include a component to measure investor return requirements, however, and so does not reflect changes in expectation affected by existing economic conditions such as increases or decreases in interest rates. (DEP Tr. vol.13, 506) Investors do not purchase stock at book value, so the market information about stock prices is not considered. (Id.)

The other study in evidence was performed by witness O'Donnell based on the Comparable Earnings model. He examined the allowed actual returns on book value (not market value) and, as a result, he found that the earned returns produced were higher than what investors require in the current marketplace. (DEP Tr. vol. 14, 225-26)

In sum, aside from his DCF study, witness D'Ascendis' cost of equity results are produced by upwardly-biased and/or improper methods and should not be given weight in the Commission's determination. The results other than the DCF were relied on by other experts only as a check on their DCF studies and should be viewed accordingly by the Commission as checks.

[113] 2019 Piedmont Rate Order at 43.
[114] *Id.*

c. Other issues that witness D'Ascendis took into consideration do not support a higher ROE.

Witness D'Ascendis also testified that he took into consideration flotation costs and other factors to increase his recommended ROE higher, (DEP Tr. vol. 11, 280-96) but these adjustment factors should be rejected. Flotation costs have not been identified, and cannot be recovered when there is no evidence that the Company expects to issue stock in the near future. (DEP Tr. vol. 15, 537, 661-65)[115] With regard to the other factors, credit ratings take into account such business risks, and DEP has a strong credit rating. (DEP Tr. vol. 13, 508-09; DEP Tr. vol. 15, 231)

B. DEP Does Not Need a Capital Structure of 52%.

When fixing a utility's rate of return pursuant to N.C.G.S. § 62-133(b)(4), one of the things the Commission must determine is the appropriate capital structure, *i.e.*, how much of the utility's investment capital should be funded by debt versus equity.[116] The reasonableness of the capital structure takes into account what is sufficient to ensure financial integrity, what is adequate to maintain credit and attract capital, and what structure is used by comparable investments.

Cost is an important factor to consider in determining a reasonable capital structure because equity capital is much more expensive than debt, particularly when related costs such as income taxes are taken into account. (DEP Tr. vol. 14,

[115] *Public Staff 2*, 331 N.C. at 221, 415 S.E.2d at 358-59.

[116] *See* 21 December 2012 Order Granting General Rate Increase to Virginia Electric & Power Company (d/b/a Dominion North Carolina Power) in Docket No. E-22, Sub 479 (Dominion 2012 Order) at 97.

231) Therefore, if the ratio of equity to debt is higher than needed, that drives up the utility's revenue requirement unreasonably.

The evidence does not support the need for a capital structure that funds ratebase using more than 51.5% common equity, the ratio recommended by witness Baudino. (DEP Tr. vol. 13, 481-82) That equity ratio is somewhat higher than the average of common equity ratios of the other companies in the proxy group. (DEP Tr. vol. 13, 483) Witnesses Woolridge and O'Donnell recommended use of a 50% equity ratio,[117] (DEP Tr. vol. 15, 620; DEP Tr. vol. 14, 243) and, although witness Newlin testified that a 53% equity ratio should be adopted, he did not support this position with technical analysis. (DEP Tr. vol.13, 481-82)

Given the relative high cost of equity capital, it is not fair or reasonable to consumers to approve an excessive ratio of equity in Duke Energy Progress' capital structures. A 51.5% equity capital structure was the actual ratio in the test year and is sufficient.

C. The Commission Must Consider the Impact of Changing Economic Conditions Upon Consumers When It Establishes the Rate of Return, and Customers Are Struggling.

In setting the rate of return, consumer interests are not a mere afterthought; accordingly, the North Carolina Supreme Court has held that the Commission must make findings of fact about the impact of changing economic conditions upon consumers when it considers what rate of return to establish pursuant to N.C. Gen. Stat. § 62-133(b)(4).[118]

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[117] Witness Woolridge accepted the 52% equity ratio agreed to in the partial settlement. (DEP Tr. vol. 15, 691-93)

[118] *State ex rel. Utilities Comm'n v. Cooper*, 367 N.C. 644, 650, 766 S.E.2d 827, 830 (2014).

While the impact of the COVID-19 pandemic and resulting economic shutdowns have not had a significant impact on the cost of capital, it has a sharp and harmful impact on consumers. An unprecedented economic contraction and steep rise in unemployment have occurred both nationally and in North Carolina. Unemployment in North Carolina rose from 3.6% in February to 12.9% in April and May. Nationally, the Gross Domestic Product (GDP) *declined* in the first quarter of 2020 by 5%, and production decreased $262.8 billion in the first quarter of 2020 whereas it increased $53 billion in the fourth quarter of 2019. (DEP Tr. vol. 13, 522-23)

In these current economic it is unreasonable to saddle consumers with an excessive rate of return. Consumers simply cannot afford it.

Cost is an important factor to consider in determining a reasonable ROE and capital structure because even small increases or decreases in the factors make a large difference in the utility's revenue requirement, particularly when the cost of income taxes is taken into account. Here, over $48 million would be shaved from DEP's annual revenue requirement if the Commission were to establish an ROE of 9.0% and 51.5% equity capital structure instead of the 9.6% ROE and 92% equity structure proposed in the Stipulation. (DEC/DEP Consolidated Tr. vol. 2, 132) This $48 million addition to DEP's cost of service will be charged to DEP's North Carolina retail customers year after year.

Customers testified about the impact of the proposed rate increase at public hearings held in January, before the effects of the COVID pandemic were felt. Even then, their key concerns included the affordability of a rate increase:

Consumers testified about the impact of the proposed rated increase at public hearings held in Franklin, Morganton, Graham, and Charlotte (DEP Public Hearing Tr. vol. 1 – DEP Public Hearing Tr. vol. 5) and identified the following key concerns:

- Low income and senior citizens or disabled persons who live on a fixed incomes will have difficulty paying an increase in utility rates. (DEP Public Hearing Tr. vol. 2, 21-22, 36, 39, 44-46, 59, 63-64; DEP Public Hearing Tr. vol. 3, 19-20, 21, 34-38, 40-42, 59-60, 62, 66, 69; DEP Public Hearing Tr. vol. 4, 15, 18, 20-23, 25-30, 32, 35-36; DEP Public Hearing Tr. vol. 5, 17-18, 20-22, 27-28, 30-31, 33-34, 38, 51-52, 55, 58-59, 72, 80-82).
- Some are forced to choose between paying for electricity and purchasing essentials like housing, other utilities, transportation (*i.e.*, gas or car repairs), prescription drugs and other healthcare needs (*i.e.*, dental care, surgical procedures, etc.), food, or educational and childcare needs. (DEP Public Hearing Tr. vol. 2, 21; DEP Public Hearing Tr. vol. 3, 34-38, 40-42, 64, 66, ; DEP Public Hearing Tr. vol. 4, 15, 18, 21-22, 25-30, 37; DEP Public Hearing Tr. vol. 5, 18, 21-22, 30-31, 33, 51, 55, 81-82).
- Duke’s proposal for the grid improvement plan (GIP) should be denied. (DEP Public Hearing Tr. vol. 2, 19, 26, 28, 36, 50, 52; DEP Public Hearing Tr. vol. 3, 26, 30, 48, 58, 68; DEP Public Hearing Tr. vol. 5, 64-65, 68-69, 77-78).

- Most witnesses opposed Duke's proposal for a rate increase to recover costs associated with coal ash basin closures given the revelations about poor operation of the ash basins, and the effect on neighboring properties and waterways. (DEP Public Hearing Tr. vol. 1 – DEP Public Hearing Tr. vol. 5)
- Several people mentioned economic and health impacts of COVID on community and others mentioned the decreased attendance related to COVID.

In conclusion, many ratepayers are having to make tough choices and need a break, particularly if the Commission intends to allow Duke to recover coal ash closure costs. If the Commission exercises its discretion by allowing Duke to recover such costs in rates, the Commission should also exercise discretion on behalf of consumers and establish a substantial reduction in the rate of return.

In sum, DEP's proposed rate of return and capital structure unnecessarily add more than $48 million each year to the revenue requirement as compared to the revenue requirement for an ROE of 9.0% and a 51.5% equity capital structure, and there is ample evidence to support the sufficiency of a 9.0% ROE. Ratepayers will be better served by keeping more than $48 million each year.

III. DEP SHOULD PROMPTLY RETURN TO RATEPAYERS OVER $400 MILLION IN EXCESS DEFERRED TAX COLLECTIONS AND OTHER OVERCOLLECTED TAXES, EITHER AS A FULL OFFSET TO A RATE INCREASE OR AS A DECREASE IN RATES.

Reductions in federal and state corporate income tax rates have lowered operating expenses for utilities.[119] As a result, DEP has accrued a large sum in federal and state deferred taxes that it no longer needs to meet its future tax liabilities. In addition, DEP has deferred revenues that were provisional and over-collected for federal taxes. (DEC/DEP Consolidated Tr. vol. 4, 69) These amounts should be returned to customers as soon as possible to help North Carolinians deal with challenging economic conditions either by applying the amounts to fully offset a rate increase or by reducing rates.

A. Factual Background

There are three income tax-related balances held by DEP at issue here that must be returned to customers, two of which are related to excess deferred income taxes (EDIT). EDIT represents monies DEP previously collected in rates to meet future tax liabilities that DEP will no longer owe.

- Most of the EDIT balance that will be returned results from changes in the federal tax rate and in the treatment of depreciation expenses adopted in the Tax Cuts and Jobs Act of 2017 (the Tax Act). This discussion is limited to the amount of Federal EDIT that may be returned over a period of time set by the Commission (unprotected EDIT). The

[119] The Commission previously ruled that this general rate case would determine how DEP would reflect the federal tax rate changes in new utility rates. *See* Order Addressing the Impacts of the Federal Tax Cuts and Jobs Act on Public Utilities in Docket No. M-100, Sub 148, issued 5 October 2018, at 69-70.

unprotected EDIT amounts to just over $400 million. (DEC/DEP Consolidated Tr. vol. 4, 72)[120]

- Additionally DEP owes customers over $24 million related to EDIT for changes in the state income tax rate. (Id.)
- The third balance is for provisional revenues that were deferred related to the overcollection of federal income taxes. (Id. at 72-73) DEP owes its customers about $122 million for the deferred revenues. (Id.)

DEP put into effect a temporary rate increase in September pending the completion of this rate case, and, to the extent that customer bills go up under the temporary rate increase, the increase is being zeroed out for the time being by offsetting the increase using some of the balance of tax money that DEP owes customers. (Id. at 73-74)

Instead of continuing that approach after final rates are approved in this case, however, DEP proposes that the remaining balances be returned gradually by spreading out the return over five years for the federal unprotected EDIT amount and over two years for the other amounts. (Id.) The Public Staff agreed to that gradual approach in a non-unanimous stipulation entered 31 July 2020. (Id.)

B. These Tax-Related Amounts Should Be Returned to Ratepayers Within Two Years Or Less.

The Attorney General urges the Commission to require DEP to return all of the amounts to ratepayers over no more than two years. There is no dispute that

[120] This issue does not relate to federal EDIT that is classified as "protected." For protected EDIT, the federal tax code prescribes its return over a time period that mimics the life of the underlying assets. (Id. at 69, 105) The AGO does not contest the approach that returns protected EDIT through base rates.

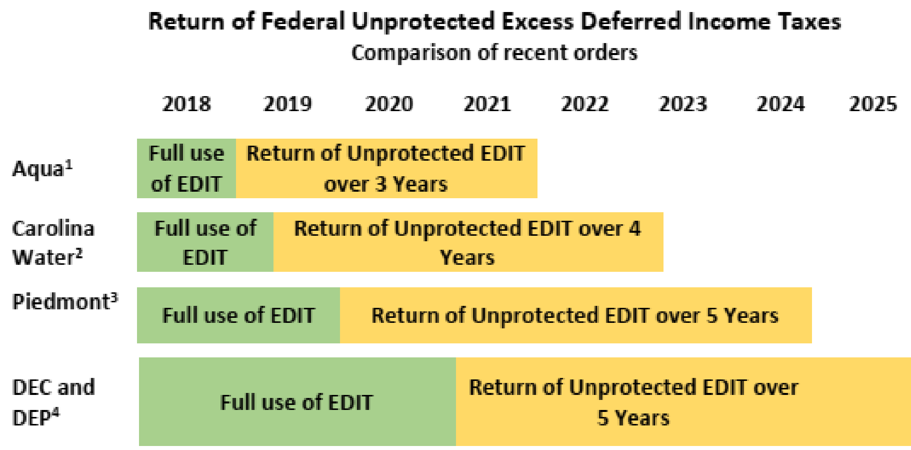
the ratepayers are entitled to these monies. (DEC/DEP Consolidated Tr. vol. 4, 67) These amounts could be used to fully offset the rate increase that the Commission authorizes in the case for some time and thereby avoid increasing rates during an emergency pandemic. DEP recognized the difficulty of asking customers to pay increased rates given the poor economic conditions and suggested a fairer approach when it offered to offset the increase while the case is pending.[121] Circumstances have not improved for customers, though, and the same offset approach is reasonable until the balances are fully returned. Alternatively, the Commission could decrease rates for a time to assist customers even further.

DEP's proposal in the July Stipulation would return federal EDIT to ratepayers over a five-year period and would return other amounts over two years. (DEC/DEP Consolidated Tr. vol. 4, 73-74) If that approach is adopted, DEP will hold onto ratepayer money for many years without good reason, and DEP will hold onto taxpayer money for longer than other North Carolina utilities. The table below shows the time line for the return of tax-related amounts approved for other North Carolina utilities compared to the proposal in this case.

[121] Amended Motion for Approval of Undertaking Required by N.C. Gen. Stat. § 62-135(c) to Implement Temporary Rates, Subject to Refund, filed 7 August 2020 at 2.

AGO McManeus/Smith Cross Exhibit 1

I/A



[1] In Aqua North Carolina's last general rate case, W-218 Sub 497, on December 18, 2018 the Commission entered the Order Approving Partial Settlement Agreement and Stipulation, Granting Partial Rate Increase, and Requiring Customer Notice, which ordered that unprotected excess accumulated deferred income taxes associated with the reduction in the federal corporate income tax rate (unprotected EDIT) shall be returned by Aqua to ratepayers in a rider to rates over a three year period.

[2] In the general rate case brought by Carolina Water Service, Inc., W-354, Sub 360, the Commission entered an Order Approving Joint Partial Settlement Agreement and Stipulation, Granting Partial Rate Increase, and Requiring Customer Notice on February 21, 2019, ordering the unprotected EDIT to be returned by Carolina Water to ratepayers through a levelized rider to rates over a four-year period.

[3] In the general rate case brought by Piedmont Natural gas, G-9, Sub ___, the Commission entered an Order Approving Order Approving Stipulation, Granting Partial Rate Increase, Line 434 Revenue Rider, Edit Riders, Provisional Revenues Rider, and Requiring Customer Notice Joint Partial Settlement Agreement and Stipulation, Granting Partial Rate Increase, and Requiring Customer Notice on October 31, 2019, ordering the unprotected EDIT to be returned by Piedmont to ratepayers through a levelized rider to rates over a five-year period.

[4] Proposal that would return unprotected EDIT to ratepayers through a levelized rider to rates over a five-year period..

(McManeus Smith AGO Cross Exhibit 1; DEC/DEP Consolidated Tr. vol. 4, 76-81) DEP's gradual approach will delay the full return of customer money for eight years from the time when the tax laws changed. That is considerably longer than other North Carolina utilities have been allowed to hold onto customer funds, even though economic conditions have worsened for customers in recent months, since the orders were issued deciding the payback periods for other utilities. The table also demonstrates that DEP has already had the full use of the funds for almost three years, which has provided considerable time for DEP to prepare for the impact of the EDIT repayment on its cash flow.

The five years agreed to under the July Stipulation is the length of time that the Public Staff recommended initially when direct testimony was filed in April, and is considerably shorter than DEP initially proposed. (DEC/DEP Consolidated Tr. vol. 4, 106) However, the improvement from DEP's unreasonably long initial proposal is not enough reason for the Commission to grant a period that is longer than allowed for other utilities. Furthermore, the initial positions of the stipulating parties were developed before the COVID-19 pandemic, and did not take into account the altered economic circumstances for many customers.

DEP argues that it is in ratepayers' interest for DEP to take longer to return all of the unprotected EDIT on its books because of the impact of the payback on the Company's cash flow and credit quality. (DEP Tr. vol.11, 644-45) DEP Witness Newlin testified that DEP would have to borrow money to return the funds as it does not have a pile of cash ready. (DEC/DEP Consolidated Tr. vol. 4, 84) However, he could not say whether customers who borrow money to pay their bills pay interest rates that are higher or lower than 18 percent, and he conceded that customers probably would not pay 2.95 percent (an amount that is close to the rates DEP has paid recently for long-term debt) (DEC/DEP Consolidated Tr. vol. 1, 96-97; DEC/DEP Consolidated Tr. vol. 4, 85) Furthermore, the cash-flow effect of EDIT repayment will be offset in part by DEP collecting from ratepayers now to prepay DEP taxes that will be due many years in the future. Under DEP's proposed revenue requirement, DEP will continue to collect $157.5 million per year for net income taxes. (DEP Tr. vol. 13, 319-21; Smith Second Settlement Exhibit 1 at 1) However, DEP witness Steven Keith Young testified that DEP's parent Duke Energy Corporation does not expect to be a significant taxpayer until the 2027 time frame. (DEC/DEP Consolidated Tr. vol. 3, 77) He agreed that tax credits and deductions have helped with cash for many years. (Id.)

Commissioners have inquired about what advantages would be achieved by linking the tax-related amounts that are going to be returned to customers to the amounts that will be recovered from customers for coal ash costs or increased depreciation expense. (*See* Public Staff Late-Filed Exhibits 3 and 4) There is not an obvious connection between the return of EDIT and either of the costs that might be offset. The proposals add to the complexity of determining rates and will likely make it more difficult for ratepayers to understand the outcome of issues that have generated interest and debate.

This matter of how to flow back the tax-related amounts falls within the Commission's discretion, and the AGO urges the Commission to exercise its discretion to require DEP to return EDIT to ratepayers within two years of the order in this case as a full offset to the allowed increase in base rates or as a rate decrease.

IV. DEP'S COSTLY INVESTMENT IN SMART METERS IS NOT YET JUSTIFIED BY THE BENEFITS BEING OFFERED TO CUSTOMERS, AND THE OPPORTUNITIES AVAILABLE TO CUSTOMERS WILL CONTINUE TO BE HAMPERED BY DEP'S USE OF NONSTANDARD, OUTDATED TECHNOLOGY FOR CUSTOMER ACCESS.

DEP has invested in costly advanced meter infrastructure (AMI), *i.e.*, smart meters and related facilities and plans to have over 1.4 million installed by early 2021 for almost all retail customers in North Carolina. (DEP Tr. vol. 11, 947) These AMI investments replaced meters that could have been used for additional years. (DEP Tr. vol. 16, 247) Smart meters have advanced features that include the capability for two-way communications and detailed interval usage measurement, and DEP claims that the technology is "customer-focused," in that it "directly provides and enables greater convenience and transparency over a customer's energy consumption." (DEP Tr. vol. 11, 946, 948) However, the reasonableness of investment in smart meters was questioned in the 2018 rate case of DEP's affiliate Duke Energy Carolinas (DEC) due to its high cost relative to the benefits offered to customers.[122] (DEP Tr. vol. 11, 879) Since that case was decided in 2018, DEP has proceeded to install smart meters across its system in North Carolina.

The concerns about the reasonableness of the investment have not been adequately addressed by DEP. This is particularly true in light of decisions DEP has made that will limit customers' benefits even after DEP's new customer information system is operational. (DEP Tr. vol. 11, 900-01; AGO Hatcher Cross Exhibit 1 and 4)[123] The new customer information system, called Customer Connect, does not incorporate available advanced standard technology that facilitates access to data by customers and their authorized third parties. DEP should be ordered to provide adequate benefits to customers by employing technology that (1) facilitates customers' use of their own data and (2) opens up options for energy conservation and demand reduction that are not limited to programs and applications offered by DEP.

The questions that arose in the 2018 DEC rate case concerned whether customers will be able to access and use the very detailed data that DEC was collecting from the smart meters.[124] (DEP Tr. vol. 11, 877-79) Smart meters were

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[122] 2018 DEC Order at 76, 124, 127, Clodfelter Dissent at 54-62, Brown-Bland Dissent at 3-4.
[123] AGO Hatcher Cross Exhibit 1 contains the Initial Joint Comments of Duke Energy Carolinas LLC and Duke Energy Progress, LLC, *In the Matter of Commission Rules Related to Customer Billing Data* filed 10 February 2020 in Docket No. E-100, Sub 161 and AGO Hatcher Cross Exhibit 4 contains the Reply Comments in that matter.
[124] 2018 DEC Order at 76, 126.

deployed to work in tandem with the implementation of Customer Connect in order to improve customer service,[125] and when Customer Connect is finally implemented, the modernized metering and customer information system could provide customers valuable access to their energy consumption data, and facilitate energy conservation and demand response.[126] (DEP Tr. vol. 11, 946, 948)

The Commission concluded in the 2018 DEC rate case that the investment in AMI was reasonable based on current and future benefits, but also concluded that DEC should be required to design and propose new rate structures to capture the full benefits of AMI.[127] DEC was ordered to file details within six months of that Order about proposed new time-of-use, peak pricing, and other dynamic rate structures that will allow customers to use information provided by AMI to reduce usage at peak times and to save energy.[128] Further, DEC was notified that "DEP's success, or lack thereof, in developing new rate structures that enable AMI energy usage benefits will be one of the factors used by the Commission in determining the prudence and reasonableness of DEC's costs incurred in deploying AMI following the present rate case."[129]

In addition to the requirements regarding the development of new rate structures, DEC was directed to continue working with the Public Staff and other interested parties to develop guidelines for access to customer usage data.[130]

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[125] *Id.* at 26.
[126] *Id.* at 76.
[127] *Id.* at 124.
[128] *Id.*
[129] *Id.*
[130] *Id.*

The advantages of AMI and Customer Connect technologies for customers have yet to be realized in DEC's rate structures and the same is true for DEP's rate structures. Further, even when the structures are rolled out, they will not yield benefits for customers that take effective advantage of AMI data because the implementation plan developed by DEC and DEP is designed in a way that limits convenient customer options to those offered by DEC and DEP. (DEP Tr. vol. 11, 900-01; AGO Hatcher Cross Exhibit 4 at 19-20)

Innovative programs and applications that would be accessible to customers from authorized third parties will not be accessible for some time because DEC and DEP plan to integrate smart meters with Customer Connect using a non-standard outdated technology that is unique to Duke called My Duke Data Download. (DEP Tr. vol. 11, 894; AGO Hatcher Cross Exhibit 2) Duke modeled its technology based on older technology called Green Button Download that has more limited capabilities than the standard technology now available. (AGO Hatcher Cross Exhibit 2) If DEC's implementation plan had incorporated the advanced and readily available "Green Button Connect" or a similar technology, customers could conveniently access their data by authorizing automated access by third parties. (DEP Tr. vol. 11, 894) Instead, customers will be required to download their data and provide it to the third party each time they want to take a look. This will make it painfully difficult for customers to use off-the-shelf advanced programs and applications that offer innovative ways for customers to shift demand to off-peak times and to improve energy efficiency. (DEP Tr. vol. 11, 975; *see* AGO Hatcher Cross Exhibit 2) The choices available to DEP's customers will be effectively narrowed to programs offered by DEP, because customers will encounter so much complexity if they wish to share their smart meter data with authorized third parties in order to make use of the innovative applications. (Id.)

DEP contends that it would be unreasonably costly to use Green Button Connect, but DEP's cost analysis indicates that the cost of the technology amounts to roughly $1.7 million over a period of five years for DEP and DEC. (DEP Tr. vol. 11, 896; AGO Hatcher Cross Exhibit 3 at 2) That is less than a percentage point of DEP's spending on AMI meters: from DEP's last rate case through June 2019, the investment was $158.3 million in North and South Carolina,[131] and DEP and another $58 million will be invested through the end of February 2021 according to projections filed in October 2019. (DEP Tr. vol. 11, 948)

Yet the investment in Green Button Connect or a similar functionality would open up options for customers to identify and use technologies that are being developed across the country – not just those offered by DEP. DEP's analysis of whether there would be interest in using Green Button Connect in the "Duke Energy Green Button Position and Cost-Benefits Analysis Corrected 2 April 2019" concludes that the interest of customers would be low because interest has been low for DEP's own programs that allow customers to view and download usage information from DEP's website in a standardized format. (AGO Hatcher Cross Exhibit 3 at 1; AGO Hatcher Cross Exhibit 4 at 21) DEP's study may reflect a lack of customer interest in using the detailed information that is now available from smart meters, but that does not bode well for the cost effectiveness of AMI meters,

[131] 2018 DEP Order at 117.

and it is plausible that customers will be more interested in accessing their data and using it for energy conservation and demand reduction if more options were available to them than those offered by DEP – options developed for wide use that are innovative, advanced, and frequently updated.

Because of the limitations built into DEP's plan for implementing Customer Connect, DEP has informed the Commission that customer access to data through Green Button Connect or a similar standard will not be available when Customer Connect is fully implemented in November 2021, and changing the implementation plan to incorporate the standard will set back the completion of Customer Connect. (DEP Tr. vol. 11, 891; AGO Hatcher Cross Exhibit 1 at 5-6; AGO Hatcher Cross Exhibit 4 at 19-20) Thus, DEP indicates that Green Button Connect or a similar standard to facilitate customer access to their detailed data (and advanced options for use of the data) will not be possible until well after the integration of Customer Connect is complete. (*Id.*) As such, the advantages that might justify DEP's large investment in AMI meters are still not proven and the potential has been limited by DEP's implementation of Customer Connect.

These limitations that have been built into DEP's plan as a result of the reliance on the outdated nonstandard technology are inconsistent with the quality of customer service expressed in the testimony of DEP witness Hatcher. He testified,

> At Duke Energy, the customer is at the center of our purpose. Evolving customer expectations, emerging technologies and changing public policies all converge to create a dynamic environment for Duke Energy and the industry . . . . Duke Energy works to build genuine connections with all customers by listening, anticipating their needs, and offering solutions.

(DEP Tr. vol. 11, 841, 891-92)

Based on these facts, DEP has not shown that its investment in smart meters is prudent and reasonable. The future potential benefits that will be available to customers are hampered by the limits that DEP has built into its system; these restrict the availability of emerging technologies and stymie customer access to new programs and applications. DEP should be directed to file revised plans that promptly incorporate Green Button Connect or another similarly advanced standard technology so that it will be incorporated into the implementation of Customer Connect without delay. If that is not possible, DEP should be directed to propose an alternative plan for providing comparable access to customers and for other measures in order to mitigate the excessive cost of AMI meters relative to the benefits that are being offered.

CONCLUSION

Ratepayers should not have to shoulder a rate increase to pay for DEP's poor decisions, including its failure to follow its own internal guidance on how to properly manage coal ash. Further, it is time to reduce DEP's rate of return to the lower level that is cost-justified according to market data. In addition, DEP should promptly return over $400 million to ratepayers that DEP holds relating to tax changes that occurred several years ago. Finally, DEP should shore up the benefits that will be available to customers from advanced metering infrastructure.

For the reasons set forth above, the Attorney General's Office asks the Commission to enter an order with the following provisions:

- Deny the coal ash recovery costs sought by DEP;
- Limit DEP's return on equity to a market-based 9.0% on 51.5% equity capital structure;
- Offset any rate increase fully or reduce rates by promptly returning DEP's excess deferred taxes and other tax-related deferred amounts to ratepayers as soon as possible; and
- Direct DEP to file revised plans for Customer Connect implementation that promptly incorporate Green Button Connect or another similarly advanced technology, and other measures to mitigate the cost of AMI meters relative to the benefits that are being offered.

These are the four issues that are addressed in this Brief. The Attorney General's Office also seeks other relief for ratepayers that the Commission finds appropriate based on the evidence in the case.

Respectfully submitted this the 4th day December, 2020.

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CERTIFICATE OF SERVICE

The undersigned certifies that a copy of the foregoing BRIEF OF THE ATTORNEY GENERAL'S OFFICE has been served upon the parties of record in this proceeding by email or by depositing a copy of the same in the United States Mail, postage prepaid, this the 4th day of December 2020.

__/s/______________________
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