STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

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

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1213 In the Matter of Application for Approval of Proposed Prepaid Advantage Program DOCKET No. E-7, SUB 1214 In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina DOCKET NO. E-7, SUB 1187 In the Matter of Application of Duke Energy Carolinas, LLC for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego	)	BRIEF OF THE ATTORNEY GENERAL'S OFFICE

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

INTRODUCTION

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

First, it is unjust and unreasonable for DEC, 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 DEC to charge ratepayers for costs to close facilities despite extensive evidence that the facilities were imprudently operated for many years. It is DEC's burden to establish the prudence of costs in light of the evidence. Because DEC has not carried this burden, DEC's proposal to recover these expenditures should be denied. Even if this burden were placed on the parties that challenge DEC's costs, the AGO and Public Staff have proven several hundred million dollars of specific cost disallowances. *See infra* § I.A, p 5.

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 44.

In addition, DEC'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 DEC has demonstrated that it is just and reasonable to pass along some or all of the costs to future

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

ratepayers, it is not appropriate or lawful for the Commission to authorize DEC to add a rate of return on the costs during deferral and amortization. *See infra* § I.E, p 46.

Further, because these are costs attributable to past service, DEC's request to recover the costs from current and future customers is based on a question of what is fair both to DEC's investors and to customers. The Commission should take into account the extensive evidence that DEC underestimated coal ash costs in past proceedings because it pushed off tasks and put off costs for generation. DEC's inaction makes it unfair to charge current ratepayers for those costs now. *See infra* § I.F, p 58.

Second, the 9.6% rate of return on equity and 52% equity capital structure proposed in the non-unanimous Stipulations[2] entered by DEC 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. (DEC Tr. vol. 16, 223-28) They would unnecessarily add more than $75 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 $75 million in local communities annually will better serve ratepayers. *See infra § II* p 71.

[2] DEC 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 DEC should be allowed an opportunity to earn. (*See* 31 July 2020 DEC-Public Staff Stipulation at 10).

Third, DEC should promptly return to ratepayers over $1 billion dollars that has accumulated in excess deferred taxes and tax-related deferred revenues. DEC 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 August. But instead of continuing to offset a rate increase, DEC proposes a slow, phased return of these funds to ratepayers once new rates take effect. Ratepayers have already waited for years to receive the benefit from these tax cuts, and DEC 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 93.

Fourth, DEC 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, DEC was authorized to recover its investment in AMI meters on the condition that it demonstrate advantages to customers. Those advantages have not yet materialized. If DEC is allowed to continue to receive full recovery of DEC'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 99.

ARGUMENT

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

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

1. The standard for cost recovery gives DEC 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 DEC's coal ash management demonstrates that DEC took no Action, despite having knowledge of the risks created by its coal ash disposal practices.

a. Background

DEC 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. (DEC Tr. vol. 16, 732) Fly ash generally tends to have much higher concentrations of metals in it than bottom ash. (DEC Tr. vol. 16, 938) 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; DEC Tr. vol. 16, 733). 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. (DEC Tr. vol. 16, 734) 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 742)

As the coal ash accumulates after combustion, it must be removed and its disposal managed. Historically, DEC 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. (DEC Tr. vol. 16, 742) 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.) Notably, all of DEC's facilities have experienced such coal ash leachate problems, resulting in decades of groundwater contamination that has continued to the present and will into the future. (DeMay AGO Direct Cross Exhibit 1; Bednarcik AGO Cross Exhibits 3-6)

DEC placed its unlined basins into stream channels or surface water conveyance channels at the bottom of valleys where they are closer to bedrock and sandy soil. (DEC Tr. vol. 16, 921) The basins, in most cases, are deep and encased in a sandy material from the weathering of the underlying bedrock, with some areas actually in bedrock. (Id.)

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 Exhibit 20; Hart Exhibit 24; DEC Tr. vol. 18, 35; Junis Exhibit 7; Junis Exhibit 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, was 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.*) 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.(Hart Exhibit 8). [3]

Evidence shows that in 1979 and 1980, power industry observers and participants were aware that the disposal of coal combustion residuals presented a significant problem. The Los Alamos Scientific Laboratory prepared a 1979

[3] DEC 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." (DEC Tr. vol 16, 861) 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 infra* § I.A, p 17, for a summary of AGO expert witness Hart's qualifications.

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. (DEC Tr. vol. 18, 35) The 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 DEC's region of North Carolina. In 1991, 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, 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. (Hart Exhibit 15) This study is especially relevant because all of the DEC facilities are located in this region. The study indicates that if the bottom of a coal ash basin is placed within the water table, the ash leachate will directly discharge to groundwater. (DEC Tr. vol. 16, 743) The bottom of DEC's basins were placed within the water table. (DEC Tr. vol. 16, 736)

Because all of DEC'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 48-55) Further, DEC's placement of the ash basins into stream channels or surface water conveyance channels at the bottom of valleys, where they are closer to bedrock and sandy soil, with some areas actually in bedrock, put the basins at the greatest risk of discharge of ash leachate to groundwater. (DEC Tr. vol. 16, 921) 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. (DEC Tr. vol. 16, 793-94) 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 DEC 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. (*Id.*)

c. DEC's Knowledge of Groundwater Contamination and DEC's Lack of Response from the 1980s through 2009

Despite these known risks and industry trends, DEC continued to place ash in unlined basins throughout the 1980s and over the decades that followed. DEC did so even though it knew that its ash basins were contaminating groundwater, and then DEC exacerbated the problem by ignoring groundwater contamination when it was detected.

In 1989, ten years after the Los Alamos Report and nine years after TVA identified the leaching of coal ash metals as a significant concern, DEC first initiated groundwater monitoring at its Belews Creek coal-fired power plant. This monitoring was part of groundwater monitoring for the adjacent Pine Hall Road CCR landfill. This first set of tests, for the period of 1989-1993, showed exceedances of 2L groundwater standards for iron and manganese. This contamination was detected in five wells adjacent to a portion of the ash basin. (DEC Tr. vol. 16, 779-80)

Despite these test results, DEC did not perform any additional monitoring to determine the extent of groundwater impacts or whether the facilities were in compliance with law at the compliance boundary. (Id. at 779-80, 801)

In 1993, groundwater contamination was detected at two additional facilities, Dan River and W.S. Lee. (DEC Tr. vol. 16, 801, 818) At Dan River, concentrations from wells located within the compliance boundary (as no wells were installed at or beyond the compliance boundary at that time) indicated concentrations of iron (up to 5,678 micrograms/liter versus the 2L standard of 300 micrograms/liter), sulfate (up to 582 micrograms/liter versus the 2L standard of 250 micrograms/liter), and manganese (up to 2,133 micrograms/liter versus the 2L standard of 50 micrograms/liter). (Id. at 801) At W.S. Lee, in the earliest reviewed data from 2004 (although the wells were installed in 1993, there is no record of any sampling data until 2004), concentration of iron was up to 21,000 micrograms/liter versus the 2L standard of 300 micrograms/liter and manganese was up to 13,000 micrograms/liter versus the 2L standard of 50 micrograms/liter. (Id. at 818)

Again, DEC did not perform additional monitoring or test whether there was contamination at the compliance boundary. These actions were not completed until DEC was required to do so by state environmental regulators in 2010-2011. (Id. at 779-80, 801)

Instead of taking action to identify the extent of contamination and monitor the sites, in February 1997, DEC notified its insurers. In the notification, DEC warned its insurers that it could face liability for violating North Carolina's 2L rules that prohibit groundwater contamination. (Hart Exhibit 25) DEC 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 DEC had actually tested the groundwater: the Allen, Belews Creek, Dan River, Marshall, and WS Lee plants. (*Id.*)

Once DEC discovered these actual or threatened violations of the 2L groundwater rules, the Rules required DEC 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. (*Id.*; 15A N.C. Admin. Code 2L.0106(c)(2), (f)(3) (2015)).

However, DEC 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 1997), it took any action to control the groundwater exceedances or eliminate the source of the contamination. Despite the 1979 Los Alamos report, the 1988 EPA report, and the 1991 EPRI report specific to the Piedmont Region, all of which showed significant risk from the practices that DEC was using to dispose of coal ash, the record is that DEC did nothing at those times to abate, contain, confirm, or control the migration of contaminants to the groundwater.

Over the decade and more that followed, staff members at DEC repeatedly acknowledged that the unlined basins at the Company's power plants were contaminating groundwater. For instance:

- In August 2003, DEC, primarily in response to the North Carolina Clean Smokestacks Act of 2002, which increased awareness of the environmental impacts associated with coal ash, sought to identify issues related to its coal ash management practices and to develop recommendations which it would then implement. (Hart Exhibit 27) DEC staff discussed the possible need to limit or stop sluicing ash to basins, and DEC staff proposed a recommendation to develop and execute a groundwater monitoring plan for all on-site (active and retired) ash management units. This plan would have been implemented in 2004. (*Id.*) However, a groundwater monitoring plan was not established until years later. (DEC Tr. vol. 16, 706)

- In September 2003, DEC discussed an alternative coal ash disposal method – dry ash handling – in its ten-year plan for managing its coal ash waste. (Hart Exhibit 26) For those facilities that did not have such systems, the plan estimated the costs for dry ash conversion in the range of $11 million to $24 million. (*Id.*) These 2003 disposal costs, multiplied by the number of DEC facilities at the time, would have been a small fraction of the amounts which DEC, after failing to take action, ultimately had to spend on coal ash disposal. (DEC Tr. vol. 16, 824-29)

  Further, DEC's 2003 plan acknowledged that it was wrong in its previous assumption that groundwater contamination was not likely. The 2003 plan further acknowledged that a cap would be required to avoid groundwater contamination at some sites. (Hart Exhibit 26)
- In 2007, DEC reexamined its coal ash management practices. (Hart Exhibit 29). During its review, DEC found that ash management decisions were becoming more complex and that the long-term environmental, legal, and financial risks were becoming more apparent. (*Id*.) DEC concluded that: 1) coal ash leaching is "worse" than previously assumed, and 2) it should move toward storing coal ash in landfills instead of unlined basins. (*Id*.)
- In 2008, in a follow-up ten-year plan, DEC took note of elevated levels at its sites of boron and other substances detected in excess of the 2L groundwater standards. (Hart Exhibit 30). This 2008 plan once again discussed dry fly ash handling, identifying that it was the most

comprehensive solution to the risk of ash basin non-compliance with environmental standards. However, the 2008 plan stated that a transition to dry fly ash handling would be cost prohibitive. (*Id.*) Costs listed for conversion to dry ash handling ranged from $11 million at W.S. Lee to $34 million at Allen. According to the 2008 plan, Allen would have been scheduled for dry ash conversion by 2009. (*Id.*) The 2008 plan further included an action item that would have required DEC to establish an Ash Management Plan, which would have provided a "glide path" for closure of ash basins to coincide with planned station retirements.

In sum, during this period of time, DEC staff and management knew that DEC's ash basins were contaminating groundwater and even acknowledged that it should begin seeking alternative disposal methods, such as liners and dry ash handling. Even so, DEC continued to put coal ash in unlined basins, failed to properly close its basins, failed to move toward safer methods of storing coal ash, and failed to resolve its groundwater contamination issues.

d. The Department of Environmental Quality Advised DEC That Its Groundwater Monitoring Was Not Being Properly Managed and Required Better Management Practices.

As early as December 1998, the Department of Environmental Quality (DEQ),[4] warned DEC of its concerns regarding DEC's management of its coal ash units and its effect on groundwater contamination. (Wells/Williams AGO Rebuttal

[4] DEQ's name has changed in recent years. This brief uses DEQ to refer not only to the current agency, but also to its predecessor agencies.

Cross Exhibit 2) DEQ informed DEC of non-compliance of significant concern: detection of exceedances of three times the 2L groundwater standard for manganese. DEQ required prompt installation of an updated monitoring system. DEQ told DEC that if compliance with the 2L groundwater rules could not be demonstrated, then DEC would need to start the process of closing the landfill where the exceedance was detected. (*Id*. at 2)

DEC did not respond by closing the landfill or by transitioning to a dry ash disposal method at the site. It is noteworthy that DEC has consistently belittled manganese exceedances, labelling them as naturally occurring, even at exceedances well beyond the level that DEQ told DEC was of significant concern and that could potentially require the closure of a landfill. (*Id.* at 2)

On 3 March 2009, DEQ again notified DEC that groundwater data received from all seven North Carolina facilities had one or more compounds above the 2L groundwater standards and that the information DEC had submitted was incomplete and insufficient. (Hart Exhibit 33) DEQ requested additional information from DEC so that DEQ could better assess DEC'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. (*Id*.) DEQ further inquired as to what actions DEC 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 DEC's wells and that DEC and

DEQ were working collaboratively, since DEQ had to request maps from DEC to determine the locations of DEC's wells, and since DEQ had to request an evaluation of the groundwater exceedances in relation to the boundaries.[5] These should have been part of DEC's original submittal. (DEC Tr. vol. 16, 852)

On 18 December 2009, DEQ advised DEC that the wells that DEC 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 DEC with recommended additional monitoring well locations. (*Id.*) DEQ further noted that it had concerns regarding some of DEC's existing wells, especially DEC-designated background wells. (*Id.*)

DEC's witness claimed that DEC was historically compliant with all of DEQ's regulations and that it had a cooperative relationship with DEQ. (DEC Tr. vol. 27, 23) However, it is apparent from these letters in 2009 that DEQ did not consider DEC's groundwater data submittals to be sufficient and had some serious reservations about the manner in which DEC 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, DEC finally established

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[5] 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. (DEC Tr. vol. 16, 699-701)

a more inclusive groundwater monitoring network and began forwarding data to DEQ. (DEC Tr. vol. 16, 823)

In 2003, prior to CAMA and the federal government's CCR Rule, DEQ filed four lawsuits against DEC 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 at six DEC plants: Allen, Belews Creek, Buck, Cliffside, Dan River, and Marshall. (*See* PS Junis Direct Ex. 1; DEC Tr. vol. 11, 946) Various third party environmental groups also expressed concern with DEC's coal ash management practices and intervened in these cases. (Id.) The lawsuits requested relief in the form of injunctions requiring the Company to address groundwater and wastewater violations at its coal ash impoundments. (Id.)

It is apparent that DEQ did not consider DEC historically compliant in its operation and maintenance of its coal ash ponds; instead, DEQ's lawsuit sought the assistance of the courts to require DEC to comply with the Clean Water Act and the North Carolina 2L groundwater rules.

e. DEC's Failure to Act and Its Poor Maintenance of Its Coal Ash Basins Culminated in the 2014 Dan River Spill.

This history shows a pattern: DEC continually gained more and more knowledge about the risks of its actions, but it did not make the necessary changes to its coal ash disposal practices. Ultimately, this passive approach to coal ash management culminated in the 2014 Dan River spill.

In 2012, DEC staff prepared a Plant Retirement Comprehensive Program Plan that discussed the closure of ash ponds in the context of plant retirement. (Hart Exhibit 39). According to the Plan, DEC intended to retire designated fossil fuel plants and close ash ponds over the next several years. At non-designated facilities, DEC's strategy was that it would transition from wet ash handling to dry ash handling systems. (*Id.*)

In 2013, DEC staff met to discuss the issue of ash basin closure and noted that the subject had recently received increased attention and scrutiny. (Hart Exhibit 37) The staff indicated that it anticipated continued focus on this issue, especially while the basins had no approved closure plans and "reasonable efforts to close them" were not underway. (*Id*.) In November 2013, DEC's ash basin groundwater data revealed exceedances of the 2L groundwater standards at the compliance boundaries. Once again, these exceedances were found at all of DEC's North Carolina coal-fired plants. DEC again admitted that there had been no attempt to mitigate the groundwater contamination. (*Id.*)

On 13 January 2014, DEC staff advised the Senior Management Committee that DEC's coal ash basins were discharging to groundwater in all locations. DEC's committee presentation warned that scrutiny regarding closure was increasing while "reasonable efforts to close basins were not underway." (Hart Exhibit 16)

Although DEC identified groundwater contamination at each of the facilities' coal ash ponds and there was an indication that the ponds would need to be closed either because of plant retirement or to address environmental concerns, DEC took little action to address coal pond closure, convert facilities to dry ash handling, or to address groundwater contamination prior to being told to do so. (Hart Exhibit 39)

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 2015 Federal Criminal action's Joint Factual Statement provides a detailed review of DEC's negligence over time in allowing this devastating spill to occur. (*Id.*)

On 12 March 2014, DEC'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)

f. The Coal Management Act

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 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. (DEC Tr. vol. 16, 770) In short, DEC's management of its ash basins was so imprudent that the legislature was forced to intervene in order to address the problems created by DEC's admitted criminal negligence.

CAMA's major provisions include the following:

- Prioritization of ash basins with timelines for their closure – the statute classified DEC's Dan River and Riverbend 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.

(DEC Tr. vol. 16, 710-12; N.C. Gen. Stat. §§ 130A-309.200 to .231)

As required by CAMA, and with input from DEQ, DEC established a site-specific groundwater monitoring network at each of the North Carolina DEC facilities during the first quarter of 2019. (DEC Tr. vol. 14, 13) Witness Bednarcik advised that these networks required a "significant" number of wells to be installed. (Id. at 14) The requirement of the number of wells at each site came from DEC "going back and forth with NCDEQ." (Id. at 18)

g. 2015 Federal Criminal Case of Criminal Negligence Related to the Dan River and Riverbend Plants.

In February 2015, the U.S. Attorney filed charges against DEC and the other Duke Energy entities with violations of the Clean Water Act. (Hart Exhibit 2) DEC pleaded guilty to criminal negligence in Federal Court in May 2015 to four counts related to the Dan River Steam Station's catastrophic coal ash spill in February 2014. (*Id.*) In addition, DEC pleaded guilty to criminal negligence to one count related to the Riverbend Stream Station for allowing discharges of contaminated water with elevated levels of arsenic, chromium, cobalt, boron, barium, nickel, strontium, sulfate, iron, manganese and zinc from a coal ash basin at the Riverbend Steam Station into an unpermitted channel which was discharged into the Catawba River for over two years, from at least November 2012 to December 2014. (Hart Exhibits 2 and 3) For all five of these counts, DEC 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.[6]

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. (*Id.*) In order to accomplish the first goal, each

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

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 DEC 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 48-53, 55)

In order to accomplish the second goal, the Rule includes provisions for mandatory groundwater monitoring of landfills and impoundments. (Bednarcik AGO Direct Cross Exhibit 2). 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.* at 3) 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.* at 8) 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.* at 6)

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.* at 7)

It is notable that all of the DEC 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. (Hart Exhibits 48-53, 55) 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. (DEC Tr. vol. 28, 25) 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. (DEC Tr. vol. 14, 14) 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 20)

Witness Wells testified that DEC hired third-party contractors to assist with the installation of the groundwater monitoring networks, but DEC retained oversight. (DEC Tr. vol. 28, 18) The final networks ultimately implemented had to be approved by DEQ. (Id. at 19) There is evidently some overlap of the wells used for the two groundwater monitoring networks, but the DEC witnesses were not able to provide any specifics as to the number of overlapping wells and where the wells were located. (Id. at 23) 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. (DEC Tr. vol. 14, 14-18, DEC Tr. vol. 28, 15)

i. DEQ's 1 April 2019 Closure Determinations at 4 DEC Sites Are Evidence of DEC's Historical Imprudent Response to Groundwater Contamination.

Under CAMA, four of DEC's coal-fired plants, Allen, Belews Creek, Cliffside, and Marshall were categorized as low risk sites. (Bednarcik AGO Direct Cross Exhibits 3, 4, 5, 6) DEC prepared closure options for the facilities and submitted those reports to DEQ, proposing that each of the sites' coal ash ponds be either closed in place or that a hybrid option be utilized. On 1 April 1 2019, DEQ rejected all of DEC's proposed closure plans for these sites, primarily based on each site containing an extensive groundwater contamination plume.

- The Allen site contains a 4,300-foot wide contaminated groundwater plume, extending beyond the compliance boundary along the entire length of both ash basins, along the eastern edge of the property on the shore of Lake Wylie. (Bednarcik AGO Cross Exhibit 3 at 9)
    - DEQ noted that the area of the plume is immense, and even 120 years beyond completion of closure, the area of the plume requiring remediation would remain extensive under DEC's proposed closure options. (*Id.* at 11)

- The Belews Creek site contains a contaminated groundwater plume above the 2L groundwater standards, extending beyond the compliance boundary along the northern edge of the property along the entire length of the active ash basin. (Bednarcik AGO Cross Exhibit 4 at 10)

  - DEQ noted that the plume is immense, and that even 118-125 years beyond completion of closure, the area of the plume requiring remediation would remain extensive under DEC's proposed closure options. (*Id.* at 14)

- The Cliffside site contains a contaminated groundwater plume above the 2L groundwater standards, extending beyond the compliance boundary near the northeast corner of the basin where a small portion of an adjacent property extends along the Broad River and in the area of the ash storage area. (Bednarcik AGO Cross Exhibit 5 at 10)

  - DEQ noted that the plume is immense, and that even 100 or 125 years beyond completion of closure, the area of the plume requiring remediation would remain extensive under DEC's proposed closure options. (*Id.* at 14)

- The Marshall site contains a contaminated groundwater plume above the 2L groundwater standards, extending beyond the compliance boundary along the northern and eastern edge on the shore of Lake Norman. (Bednarcik AGO Cross Exhibit 6 at 10)

  - DEQ noted that the area of the plume requiring remediation is immense and that even 120 years beyond completion of closure, the area of the plume requiring remediation would remain extensive under DEC's proposed closure options. (*Id.* at 11)

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 DEC'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 48-55)

* * *

In sum, there is extensive evidence that:

- As far back as 1979, the power industry was aware of the dangers posed by coal ash disposal practices, and a Los Alamos Laboratory report warned that groundwater contamination from coal ash ponds like the ones used by DEC were a problem of great significance.
- In 1989, DEC conducted groundwater monitoring for the first time, and it found groundwater contamination.
- In 1991, a study identified that environmental risks were present specifically in the Piedmont Region, where DEC's facilities were located.
- By 1993, DEC had identified groundwater contamination at two sites.
- In 1997, DEC reported to its insurers that its coal ash basins had contaminated groundwater at five sites.
- Beginning in 1998, DEQ began to warn DEC of its concerns about groundwater contamination from DEC coal ash disposal.
- No later than 2003, DEC began to discuss transition to dry ash handling instead of its current methods of disposal.
- By 2008, DEC had developed cost estimates for conversion to dry ash handling.

- Yet it was not until after the Dan River spill in 2014 that DEC took action to change its practices.

There is extensive evidence that DEC's inaction was unreasonable, that DEC illegally polluted groundwater in violation of the 2L groundwater rules, and that DEC's costs today are due to this unreasonable past conduct.

B. DEC Has Not Shown That It Incurred Its Coal Ash Costs Reasonably.

1. The standard for cost recovery places the burden on DEC 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 to be 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).

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).

2. DEC's violation of North Carolina's 2L Groundwater Rules and pollution of groundwater via its unlined coal ash basins was not reasonable or prudent.

As evidenced by the history of DEC's coal ash management, DEC 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 DEC unreasonably managed its unlined basins—mismanagement that eventually resulted in the spill at Duke's Dan River plant, which then led to the discovery of additional criminal negligence at other sites, including Riverbend's illegal discharge of contaminated water into the Catawba River for at least two years. (Hart Exhibit 3)

DEC could have prevented or at least have taken corrective action to address these violations. DEC's internal historical evidence reflects that it was aware of its non-compliance as early as 1997, when DEC 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. (Hart Exhibit 25; DEC Tr. vol. 16, 770-824)

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 1989 and 1993, DEC did not act reasonably or prudently. By failing to adhere to proper coal ash management, DEC incurred costs that it could have avoided. (DEC Tr. vol. 16, 824-29) For example, if DEC 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. (DEC Tr. vol. 16, 709, 824-29)

Likewise, if Duke had built lined landfills at its plants sooner, it could have avoided the cost of transporting ash to off-site landfills. Because of Duke's delay in building lined landfills, it has incurred transportation costs to meet CAMA's deadlines for closing coal ash basins. (DEC Tr. vol. 20, 247)

In sum, Duke acted unreasonably by failing to alter its coal ash management practices by continuing to put ash into unlined basins after Duke 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.

a. DEC violated the state's environmental laws.

The evidence shows that DEC 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 DEC's environmental violations, DEC's criminal convictions, and the events that followed from them, present "affirmative evidence" that challenge "the reasonableness of [DEC's] expenses." *Bent Creek*, 305 N.C. at 76, 286 S.E.2d at 779. This showing of DEC's mismanagement is more than enough to require DEC 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.[7] 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. (DEC Tr. vol. 16, 739-731) Similarly, a federal court has held that the 2L rules are

[7] 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); DEC Tr. vol. 16, 793-94)

"*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).

b. 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*, 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).[8]

[8] *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).

Accordingly, the Commission has a duty to assess DEC's reasonableness based on all of the "relevant, material and competent evidence" in the record, N.C. Gen. Stat. § 62-133(c), including evidence of violations of environmental law, regardless of whether DEC admits to wrongdoing, and regardless of whether a court has expressly held that violations have occurred.

The history of actions relating to DEC'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 DEC'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, 95/6) 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 Duke's violations of the 2L groundwater rules, with several environmental groups intervening. (DEC Tr. vol. 20, 429; DEC Tr. vol. 11, 946-947; Junis Exhibit 1) Before the State's 2013 lawsuits reached judgment, however, the Dan River spill occurred. In response to the spill, to stop Duke 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 Duke's request, granted partial summary judgment on the State's claims. The court stated that Duke'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 Duke from polluting the state's groundwater.

As these events show, CAMA made it unnecessary for the court in the 2013 case to decide whether Duke violated the 2L rules, as long as DEC complies with CAMA and DEQ's implementation of CAMA. But, given that CAMA was a response to Duke'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 DEC'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. DEC 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 Allen, Belews Creek, Cliffside, and Marshall, as noted by DEQ in their April 2019 closure determinations at these sites. (Bednarcik AGO Direct Cross Exhibits 3, 4, 5, 6) 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. (DEC Tr. vol. 16, 824-829)

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

c. DEC 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 DEC to demonstrate the extent to which its costs were reasonable despite affirmative evidence that DEC incurred its coal-ash costs due to its own unreasonable conduct,. Duke has not carried this burden, because its evidence is inconclusive and does not quantify with precision the effect of DEC'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 Duke seeks rate increases, it bears the burden of persuasion, because it is the party that has "knowledge of the facts."[9] *Peace v. Emp't Sec. Comm'n*, 349 N.C. 315, 328, 507

[9] 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"

S.E.2d 272, 281 (1998). DEC's access to information, and the duties conveyed by that knowledge, were in sharp relief here. Both CAMA and the CCR Rule require the installation of a groundwater monitoring network at all sites. Witness Bednarcik testified that each of these networks required a "significant" number of wells to be installed.(DEC Tr. vol. 14, 14) For example, Allen required a total of 136 CAMA network wells and 72 CCR network wells, while Cliffside required a total of 253 CAMA network wells and 79 CCR network wells. (Hart Exhibit 51; Hart Exhibit 48) When cross-examined, neither Bednarcik nor witness Wells were able to provide information as to how many pre-existing wells were able to be used in the networks or the number of wells that could be used for both networks at each site. (DEC Tr. vol. 14, 14-18; DEC Tr. vol. 28, 15). At the hearing, witness Bednarcik could not testify to the specific cost of the wells at each site, but advised that the approximate costs of the installation of the wells would be in the Company's line item for groundwater monitoring, which would include both installation and monitoring. (DEC Tr. vol. 14, 19) 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. (DEC Tr. vol. 28, 15) Gaps in the record are the result of Duke's own decisions about what evidence to present. DEC 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 DEC's conduct before 2014 affected the current costs, DEC is responsible for that gap in the evidence.

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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.

The burden is DEC'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 DEC'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. (DEC Tr. vol. 20, 451) 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. (Id.) As Junis testified, "[w]hile the Company calls these 'compliance' costs to meet CAMA and CCR Rule requirements, they also reflect DEC's non-compliance with longstanding environmental regulations." (Id. at 451-52)

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 DEC'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 DEC 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 February 24, 2020 Final 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 two adjustments to specific costs deferred during the period. The first adjustment would not allow DEC to recover expenditures made to connect certain properties near its coal plants to alternate water supplies, and the second 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. (DEC Tr. vol. 16, 824)

The requirement that Duke connect all households in some areas near its coal plants to alternate water supplies added an estimated $17.5 million to the total coal ash expenditures for the system, based on the costs shown in DEC witness Bednarcik's direct testimony that identified expenditures as of [date] [10] (DEC Tr. vol. 16, 826, 829) 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. (DEC Tr. vol. 16, 826) Had DEC determined the extent of groundwater problems at its coal plants by

[10] Witness Hart used the information available from DEC 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 for later work papers from DEC, and to include the related amount recovered for rate of return during deferral of the costs, and to quantify the North Carolina retail share. (DEC Tr. vol. 16, 829)

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.)

Moreover, these alternate water connection costs were caused by DEC's imprudence even at properties where no evidence has been presented of contamination bearing DEC's fingerprint. After the Dan River spill, it came to light that groundwater problems were occurring at all of DEC's coal plants, and the contamination occurring near DEC's ash basins became notorious. (Hart Exhibit 3; Hart Exhibit 38; Hart Exhibit 16) The requirement that DEC provide an alternate water supply was prompted by diminished trust in DEC's operations. DEC's failure to maintain the basins in compliance with groundwater requirements and its admission to criminal negligence at some of its plants were widely publicized. (Hart Exhibit 2; Hart Exhibit 3)

As AGO witness Hart testified, another appropriate specific adjustment to DEC's coal ash expenditures reflects 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 DEC 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. (DEC Tr. vol. 16, 827) Witness Hart calculated the effect of inflation on costs assuming that the same work would have been done had DEC 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. (DEC Tr. vol. 16, 826)

Hart began his calculation with the $406 million in coal ash costs identified in DEC exhibits. Then, Hart adjusted the amount to remove the water supply connection costs of $17.5 million discussed earlier, and Hart removed a fee that DEC paid for termination of a contract with Charah.[11] Hart identified several points in time when the evidence shows that DEC 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. (DEC Tr. vol. 16, 827)

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

- 1989 (when groundwater contamination was first documented) - $190 million (MM)

- 1993 (when groundwater contamination was detected at two additional facilities — Dan River and WS Lee — and just before notice to insurance carriers of contamination above standards at Allen, Belews Creek, Dan River, Marshall, and WS Lee) - $140 MM

- 2003 (when internal documents demonstrate DEC's knowledge of groundwater contamination issues, possible need to limit or stop sluicing ash to basins, and need to develop consistent and measured approach to address groundwater contamination) - $100 MM

- 2010 (when DEQ began to require that DEC collect groundwater data at the compliance boundary) - $50 MM

(DEC Tr. vol. 16, 828)

[11] Hart identified the Charah costs as a contract issue and did not address whether those were appropriate for cost recovery but excluded it from his analysis of the reduction attributable to inflation. (DEC Tr. vol. 16, 28)

Thus, witness Hart testified DEC's costs for the system would be reduced by between approximately $50 million and $190 million if the process of closing ash basins had started earlier, when DEC had identified groundwater contamination. Witness Hart added this $50-$190 million range to the costs of alternate water supplies (an estimated $17.5 million) to determine the total minimum disallowance. (DEC Tr. vol. 16, 829)

In addition, Public Staff witness Garrett[12] provided two bases for specific disallowances of costs. (DEC Tr. vol. 20, 204) First, Garrett reviewed the Charah contract with DEC and determined that $46,142,699 of the fulfillment fee DEC paid to Charah should be disallowed. (Id.) Second, Garrett re-examined the facts and the current status of the Dan River Steam Station's construction of a landfill and opined that $29,250,905 of the costs paid for excavation of the Dan River site should be disallowed. (Id. at 204, 247)

Public Staff witness Moore[13] provided another basis for a specific disallowance of costs. (DEC Tr. vol. 20, 191) Moore reviewed the costs of the Buck Steam Station beneficiation unit. Moore opined that the termination of the contractor H&M and the employment of the contractor Zachry to construct the beneficiation unit was unreasonable and that $67,809,160 of the costs paid for the beneficiation unit should be disallowed. (Id.)

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[12] 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. (DEC Tr. vol. 20, 192, 199-200)

[13] 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. (DEC Tr. vol. 20, 168, 192)

Finally, Public Staff witness Junis[14] provided evidence of three more bases for specific disallowances of cost. (DEC Tr. vol. 20, at 459) The first specific disallowance relates to the accelerated groundwater extraction and water treatment at the Belews Creek Steam Station in the amount of $298,433 for the period of January 2018 through November 2019. (Id. at 460) As Junis testified, these costs, which exceed what CAMA would have required, would not have been incurred but for DEC's groundwater violations at Belews Creek. (Id.)

The second specific disallowance discussed by Junis (in conformance with witness Hart's first adjustment) relates to the requirement by the legislature that DEC 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. Junis testified that those costs amounted to $16,882,665 on a system basis from the period of January 2018 to November 2019. (Id. at 460-61)

The third specific disallowance discussed by Junis 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. Junis testified that those costs amounted to $962,524 on a system basis from the period of January 2018 to November 2019. (Id. at 461-62)

[14] Public Staff witness Junis is an engineer with the Water, Sewer, and Telephone Division of the Public Staff – North Carolina Utilities Commission. Junis is a licensed Professional Engineer and has a B.S. in Civil Engineering with over eight years of engineering experience. (DEC Tr. vol. 20, 401, 474)

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

On March 29, 2017, the Company, along with Duke Energy Progress, LLC, 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"). (DEC Tr. vol. 11, 939; 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.[15] 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. (DEC 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,

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

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. (DEC Tr. vol. 11, 943)

In the Commission's June 2018 Duke Energy Carolinas Order, the Commission made the following Findings of Fact:

> 76. It is appropriate to require that, within 10 days of the resolution by settlement, dismissal, judgment or otherwise of the litigation entitled Duke Energy Carolinas, LLC, et al. v. AO Insurance SA/NV, et al., Case No 17 CVS 5594, Superior Court (Business Court), Mecklenburg County, North Carolina (Insurance Case), DEC shall file a report with the Commission explaining the result and stating the amount of insurance proceeds to be received or recovered by DEC. This reporting requirement shall apply even if the case is appealed to a higher court.
>
> 77. It is appropriate that DEC be required to place all insurance proceeds received or recovered by DEC in the Insurance Case in a regulatory liability account and to hold such proceeds until the Commission enters an order directing DEC as to the appropriate disbursement of the proceeds. In addition, the regulatory liability account shall accrue a carrying charge at the net-of tax overall rate of return authorized for DEC in this Order.

(DEC June 2018 Order at 24.) These Findings of Fact were later echoed in the decretal portion of the Order. (Id at 326, 333)

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 DEC 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 DEC has demonstrated that the coal ash costs are recoverable, it is not appropriate or lawful for the Commission to authorize DEC to add a rate of return on the costs during deferral and amortization. DEC's proposed increase includes not only 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. (DEC Tr. vol. 15, 129-31) DEC witness McManeus testified that DEC seeks to recover $378.5 million from North Carolina retail ratepayers for coal ash closure costs that have been deferred from 1 January 2018 through 31 January 2020. Of this sum, $36.8 million is for the "financing cost" based on the Company's weighted average cost of capital. (DEC Tr. Vol. 15, 129-30; McManeus Supplemental Exhibit 1 at 57) 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 DEC will continue to earn a rate of return until the costs are fully recovered. (DEC Tr. vol. 15, 130-31) The total added to the Company's annual cost of service is about $96 million: $76 million in amortization (including the expenditures and financing during deferral) and about $20 million more for rate of return during the amortization period. (Id.)

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

DEC'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.[16] Only the utility's ratebase, not its operating expenses, is eligible to be multiplied by a rate of return.[17] 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.[18]

Here, DEC must show that its coal ash costs meet the test for inclusion in ratebase. DEC 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.[19] In *Thornburg II*, this Court explained that, for everything other than construction work in progress, a two-part test decides that goes into a utility's ratebase:

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[16] *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).

[17] *Thornburg I*, 325 N.C. at 475, 385 S.E.2d at 458; N.C. Gen. Stat. § 62-133(b)(5).

[18] *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).

[19] *Morgan*, 277 N.C. at 268, 177 S.E.2d at 414.

- First, the Commission must “determine the reasonable original cost of the property.”[20]
- 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.”[21]

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.”[22]

The Court’s *Carolina Trace* opinion illustrates what it means for property to be used and useful for providing current utility service.[23] 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.[24] 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.[25]

Here, DEC 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

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[20] 325 N.C. at 491, 385 S.E.2d at 466-67 (citing N.C. Gen. Stat. § 62-133(b)(1)).
[21] *Id.*
[22] *Id.*
[23] 333 N.C. 195, 424 S.E.2d 133.
[24] *Id*. at 197-99, 424 S.E.2d at 134-35.
[25] *Id*. at 202-03, 424 S.E.2d at 137.

enjoyment are exercised."[26] DEC's coal-ash costs, in contrast, mainly involve expenditures made for basin closure and treating contaminated groundwater. (DEC Tr. Vol. 13, 206, 209-11, 215) Those costs are typically accounted for as operating expenses. In fact, DEC referred to its costs as expenses when it initially requested authority to defer them for recovery in later periods. (AGO McManeus/Speros 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." (DEC Tr. vol. 13, 204-19)[27] 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.; DEC Tr. vol. 16, 770-837) None of the expenditures that DEC 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. DEC called its active plants' costs "non ARO" costs and accounted for them separately. (DEC Tr. vol. 13, 15, 127)

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

[26] *Property*, Black's Law Dictionary 1410 (10th ed. 2014).
[27] N.C. Gen. Stat. § 62-133(b)(1); (b)(3).

is no statutory authority for including in ratebase costs from a completed plant that is no longer used and useful."[28]

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.[29] 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.[30]

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.[31]

DEC'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. (DEC Tr. vol. 16, 836) In fact, most of DEC'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, DEC 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 1920s. (Hart Exhibits 50 and 54) 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 DEC a return on expenditures made now relating to electric service to past customers.

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[28] *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).
[29] 333 N.C. at 197-98, 424 S.E.2d at 134-35.
[30] *Id*. at 202-03, 424 S.E.2d at 137.
[31] N.C. Gen. Stat. § 62-133(b)(1).

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 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,[32] 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.[33]

Indeed, the Commission has previously followed this distinction in a 1994 general rate case for Public Service Company of North Carolina.[34] That case addressed the costs of cleaning up environmental contamination at Public Service Company's manufactured-natural-gas plants.[35] 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.[36]

As these decisions illustrate, DEC'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 DEC to recover a rate of return on the costs.

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[32] 325 N.C. at 493, 385 S.E.2d at 468.
[33] *Id*. at 496, 385 S.E.2d at 470.
[34] 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.
[35] *Id.* at 23.
[36] *Id.*

2. DEC'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 DEC 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 DEC's coal-ash removal costs are "property used and useful, or to be used and useful within a reasonable time after the test period, in providing the service rendered to the public,"[37] and no exception to the used and useful requirement is provided for an ARO in the ratemaking statute.[38]

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."[39] As DEC witness Riley testified, "…accounting does not impact ratemaking; ratemaking impacts the accounting." (DEC Tr. vol. 23, 140)

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."[40] The principle was also recognized in 2003 when the Commission authorized the use of deferral accounting for legal

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[37] N.C. Gen. Stat. § 62-133(b)(1).
[38] *Id.*
[39] *State ex rel. Utilities Com. v. Edmisten*, 291 N.C. 451, 464, 232 S.E.2d 184, 191 (1977); accord *State ex rel. Utilities Comm'n v. North Carolina Power*, 338 N.C. 412, 421-22, 450 S.E.2d 896, 901-02 (1994); *Carolina Trace*, 333 N.C. at 203, 424 S.E.2d at 138.
[40] February 2020 Dominion Order at 133.

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.[41] 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 "shall be to reset [DEC'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."[42]

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

3. The rate of return DEC 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.

DEC 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*. (DEC Tr. Vol. 15, 89)[43] In that case, our Supreme Court held that working capital may be included in a utility's ratebase.[44] The Court defined working capital as "the utility's own funds reasonably

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[41] Order Granting Motion for Reconsideration and Allowing Deferral of Costs issued 8 August 2003 in Docket No. E-7, Sub 723 admitted in evidence as AGO McManeus/Speros Exhibit 2 at 11-12 (2003 ARO Accounting Order)
[42] *Id.*
[43] *State ex rel. Utilities Commission v. Virginia Electric & Power Co*. (*VEPCO*), 285 N.C. 398, 206 S.E.2d 283 (1974).
[44] *Id*. at 414-15, 206 S.E.2d at 295-96.

invested in . . . materials and supplies and its cash funds reasonably so held for the payment of operating expenses, as they become payable."[45]

The Commission rejected this argument in its recent order in the Dominion case.[46] 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.[47] For an asset to get rate-base treatment, it must not only have been funded by the utility's investors, but must also meet the requirement in N.C. Gen. Stat. § 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.[48]

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.[49] 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 DEC 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

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[45] *Id.*
[46] February 2020 Dominion Order at 132-33.
[47] *Id.*
[48] *Id.*
[49] 277 N.C. at 273, 117 S.E.2d at 417.

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:

- 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.[50] This Court held that as a matter of law, these excess facilities were not used and useful.[51]

- In *Carolina Water*, a utility was facing unrecovered costs that resulted from the early retirement of a wastewater-treatment plant.[52] 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."[53]

- 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

[50] 325 N.C. at 486, 385 S.E.2d at 464.
[51] *Id*. at 495, 385 S.E.2d at 469.
[52] 335 N.C. at 507, 439 S.E.2d at 135.
[53] *Id.* at 508, 439 S.E.2d at 135.

utility's rate cases.[54] Because of that timing, the property never qualified as used and useful. [55]

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 service during the test year.[56] DEC has not shown that its coal ash expenses meet the used-and-useful requirement, and the "working capital" argument must fail.

4. 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.[57]

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

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[54] 333 N.C. at 203, 424 S.E.2d at 137.
[55] *Id*.
[56] *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*).
[57] *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, 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 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. Gen. Stat. § 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 DEC to receive a return on its coal ash costs, and DEC 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. DEC 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 DEC'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 Order.[58] Although the Commission did not find that challengers provided sufficient evidence that specific coal ash costs increased due to imprudent management of Dominion's ash basins,[59] 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.[60] 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.[61] Instead, the costs in those cases were allocated between the utility's investors and customers. [62]

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

[58] Dominion Energy North Carolina general rate case order issued 24 February 2020 in Docket No.E-22, Sub 562. (February 2020 Dominion Order) at 131.
[59] 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.
[60] February 2020 Dominion Order at 131.
[61] *Id*. at 130-31 (citing a 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); 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).
[62] *Id.*

same generation of customers who benefit from service should pay for the cost of that service.[63] 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."[64]

These principles of the fairness and timing of cost recovery are basic considerations that are overlooked in the standard that DEC has proposed for determining what coal ash costs should be recoverable in new rates.[65] 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.

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[63] 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.

[64] *Id.*at 122.

[65] In its last rate case, DEC 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. 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., *State ex rel. Utilities Comm'n v. Carolina Util. Customers Ass'n*, 348 N.C. 452, 458, 500 S.E.2d 693, 698-99 (1998).

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. Gen. Stat. § 62-133(a). The statutory formula describes particular requirements for ascertaining the <u>reasonable</u> ratebase and <u>reasonable</u> operating expenses, and for fixing a <u>fair</u> rate of return. N.C. Gen. Stat. § 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 <u>reasonable and just</u> rates." N.C. Gen. Stat. § 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. DEC'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. (DEC Tr. vol. 15, 136) DEC accounting witness McManeus 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." (DEC Tr. vol. 15, 136) 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. (DEC Tr. vol 16, 137-38)

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."[66] 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." [67]

The Commission recognized the significance of the matching principle – and how it has been addressed in DEC's past accounting for the retirement costs associated with long-lived assets – when changes to financial accounting standards were reviewed in 2003.[68] The Commission recognized that the accounting for long-lived assets – including retirement costs of those assets – was at that time being addressed in DEC's established rates by the inclusion of a component for the recovery of closure costs over the life of the assets, not for

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[66] *State ex rel. Utilities Com. v. Edmisten* (*Edmisten*), 291 N.C. 451, 470, 232 S.E.2d 184, 195 (1977).
[67] *Id.*
[68] The Order Granting Motion for Reconsideration and Allowing Deferral of Costs in the Matter of Duke Power's Petition for Authority to Place Certain Asset Retirement Obligation Costs in a Deferred Account issued 8 August 2003 in Docket No. E-7, Sub 723, was admitted as AGO McManeus/Speros Cross Exhibit 2 (2003 ARO Order).

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 emphatically directed DEC to seek authority for a change in accounting *before* implementation. (2003 ARO Order at 11, 13)

The direction to DEC that it should seek authority before changing how retirement costs are accounted for in future rates was particularly important 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. [69]

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

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

the shareholders, but also concluded that ratepayers should not bear the entire risk and rate impact of the liabilities associated with coal ash. 2020 Dominion Order 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.*
- 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 DEC 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 DEC'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 DEC's negligent actions and inactions and the risks accepted by those managing DEC's coal ash ponds, and will not be repeated here.

- The magnitude of the total costs during the deferral period is significant and DEC's proposal imposes a large charge on ratepayers. The revenue requirement in this case is increased $96 million for the coal ash costs deferred from 1 January 2018 through 31 January 2020 under DEC's proposal. (DEC Tr. vol. 15, 131-32) That is in addition to the roughly $120 million per year already reflected in the revenue requirement. (Id.) Together, over $200 million is reflected in the annual revenue requirement for North Carolina retail customers. While the costs will not be allocated on a per-customer basis, roughly speaking the impact would be about $100 per customer per year. (DEC Tr. Vol. 15, 135)

- 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 the unfairness of imposing these past costs on current and future ratepayers. DEC 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.

DEC admits that it did not submit any request to the Commission to identify increased costs of depreciation relating to the specific cost of removal for coal ash basins. (DEC Tr. vol. 23, 48) In fact, DEC *decided* not to seek a specific increment relating to coal ash costs in depreciation or dismantlement cost, and instead to wait to make the request for cost recovery until after it recognized a legal asset retirement obligation in financial records associated with the costs. (DEC Tr. vol. 22, 211-13; DEC Tr. vol. 23, 48) DEC witness Spanos, who prepared depreciation cost studies in this and previous DEC cases, testified that he "was not asked to include coal ash closure costs in the calculation because it was going to be an ARO." (DEC Tr. vol. 23, 48) He recalls that the costs might have been considered too speculative to include. (Id.)

DEC's decision *not* to address the coal ash basin retirement costs is problematic for its disregard of the Commission's ratemaking treatment of such costs in depreciation expenses. 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 DEC 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 4, 10-11) 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. DEC 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) 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.

Furthermore, the record shows that DEC knew – or should have known – from industry publications and internal reports that the costs would be significant to close the ash ponds.

- DEC did not file an application for a rate increase between 1987 and 2008, and did not include a specific increment for coal ash when applications were filed subsequently, nor did it include a specific increment in depreciation studies. (DEC Tr. vol. 22, 206)
- Witness Spanos testified that net salvage estimates were included in cost studies in 2003 but were not updated in subsequent studies as costs increased. (DEC Tr. vol. 22, 206-207)
- Internal documents for DEC show that the cost to close ash basins was expected to be substantial. (DEC Tr. vol. 22, 211)
- 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. (AGO Doss Spanos Rebuttal Cross Examination Exhibit 1 at 2-5)[70]

[70] 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 Tr. vol. 22, 211-12)
- 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.[71]
- Since DEC constructed its basins in streambeds and low-lying areas, it should have known that a cap over the basins would not address groundwater requirements, and likely more costly measures would be needed. (DEC Tr. vol. 16, 921)

On the other hand, DEC has indicated it simply did not anticipate the costs would be significant enough to offset the net salvage value of the related assets:

- DEC responded that the costs to close ash impoundments were not factored into the depreciation study, and explained that “’i]t was assumed in the last dismantlement study [which occurred before the passage of CAMA] that the salvage received for scrap would sufficiently offset the costs to dismantle.” (AGO McManeus/Spero Cross Exhibit 5)

Taken together, the facts about DEC’s failure to address coal ash costs in its depreciation and dismantlement studies negligently postponed the cost recovery to its future customers.

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

Because DEC'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, and DEC's admission that it waited until the recognition of a legal ARO to address the costs shows an unfair disregard for the burden it now seeks to impose on current and future customers. As the Commission explained in the Dominion Order, the matching principle is violated by DEC's recovery of these past costs from future customers. (Dominion Order at 122) DEC'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 DEC's long-time accounting for such assets *over the life of the assets.*

DEC did not submit any request to the Commission to identify increased costs of depreciation relating to the specific cost of removal for coal ash basins, or seek a change in how the accounting for coal ash would be addressed until after it recognized a legal asset retirement obligation in financial records associated with the costs. (DEC Tr. vol. 22, 211-13; DEC Tr. vol. 23, 48) 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, DEC'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 DEC's investors, and DEC'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,[72] which is fairer to consumers than what DEC 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 DEC has managed the facilities.

DEC's proposal, by comparison, includes full recovery over a short five-year amortization period plus a rate of return that DEC 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 DEC's last rate case that allowing a rate of return converts the "relief" sought in the initial Petition into "a new

[72] 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.

opportunity for capital investment and for profit-making" in the eyes of investors.[73] DEC witness Newlin confirmed this view when he testified that investors see the coal ash costs as an investment and expect a return. (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 operations, disclosures of contamination problems at all of DEC's plants, and now admissions that DEC decided to wait until it recognized a legal ARO to seek specific cost recovery – years after it knew that the costs would be very substantial.

The alternative suggestion that DEC'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 DEC 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.[74]

II. DEC'S SETTLEMENT PROPOSAL, WHICH WOULD FIX AN UNJUSTIFIABLY HIGH 9.6% RATE OF RETURN ON EQUITY AND 52% EQUITY CAPITAL STRUCTURE, ADDS OVER $75 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 DEC's rate of return based on evidence that is well supported by current market indicators. DEC has not met its burden of proof that the 9.6%

[73] 2018 DEC Rate Order Clodfelter Dissent at 45
[74] *Edmisten*, at 468-69, 232 S.E.2d at 194; *see* McDermott, Cost of Service Regulation at 9.

ROE and the 52% equity capital structure proposed in the partial settlement[75] are required in order for DEC to attract the investment dollars needed for adequate service. Nor has DEC 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,[76] Public Staff witness J. Randall Woolridge,[77] and CUCA witness Kevin W. O'Donnell.[78] *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 the actual ratio DEC maintained during the test year. This capital structure is also less costly and fairer to consumers. The rate of return factors that DEC proposes in the Partial Settlement would unnecessarily add over $75 million to DEC's annual revenue requirement.[79] (DEC/DEP Consolidated Tr. vol. 2, 132) It is time to reduce DEC's rate of return to the lower level supported by market data, particularly given the dire economic conditions many customers face.

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[75] 31 July 2020 DEC-Public Staff Stipulation at 10.

[76] 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. (DEC Tr. vol. 16, 396-412).

[77] 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. (DEC Tr. vol. 17, 214-15)

[78] 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. (DEC Tr. vol. 20, 24-25)

[79] 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.

Furthermore, if — as DEC 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. DEC'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 DEC 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*."[80] Under the statute, the rate of return should allow the utility to "compete in the market for capital funds" on reasonable terms.[81] The statute cautions that those terms must be fair not only to the utility's existing investors, but also to its customers,[82] and the Commission must take into account the interests of customers when it fixes the return on equity.[83] In the words of our state's Supreme Court, the rate of return provision "advances the Legislature's twin goals of assuring sufficient shareholder investment in utilities while simultaneously maintaining the lowest possible cost to the using public for quality service."[84]

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[80] 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).
[81] *Id.*
[82] *Id.*
[83] *Cooper 2*, 367 N.C. at 440, 758 S.E.2d at 641 (internal quotation marks and citation omitted).
[84] *Id.* at 440, 758 S.E.2d at 641 (internal quotation marks and citation omitted).

DEC's capital structure includes both long term debt and common equity.[85] Determining the rate of return on debt is generally straightforward, but the return on common equity (ROE) is more difficult to determine.[86] 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.[87] 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."[88]

The test laid down in N.C. Gen. Stat. § 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."[89] The determination must take into consideration changing economic conditions and other factors as they then exist.[90] Early United States Supreme Court cases established guiding principles which the General Assembly subsequently incorporated into the North Carolina ratemaking statute,[91] holding that the rate of return is one "which will enable the utility "by sound 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

[85] Johnson Settlement Exhibit 1, Line 6; Off. Ex. Vol. 6 p 3.
[86] *Public Staff*, 322 N.C. at 697-98, 370 S.E.2d at 572-73.
[87] *Id.*
[88] *State ex rel. Utilities Comm'n v. Cooper* (*Cooper*), 366 N.C. 484, 495, 739 S.E.2d 541, 548 (2013).
[89] *Utilities Comm'n v. Duke Power Co.* (*Duke Power*)*,* 285 N.C. 377, 393, 206 S.E.2d 269, 280 (1974).
[90] N.C. Gen. Stat. § 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).
[91] *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).

market for capital."[92] 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. (DEC Tr. vol. 11, 61-62; DEC Tr. vol. 16, 320; DEC Tr. vol. 17, 320)

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.

DEC 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, (D'Ascendis DEC Tr. vol. 11, 50, 116-17, 148-50; Woolridge Tr. DEC vol. 16, 229-30), 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.[93] 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 weight to ROE decisions by other regulatory authorities.[94] The Court found that the decisions by other regulatory authorities "fail[ed] to support the Commission's

[92] *State ex rel. Utilities Comm'n v. General Tel. Co.*, 281 N.C. 318, 370, 189 S.E.2d 705, 738 (1972).
[93] *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.
[94] *Public Staff 2,* 331 N.C. at 225, 415 S.E.2d at 361.

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."[95] 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." [96]

Contrary to the holdings in these Supreme Court's decisions, DEC's expert encourages the Commission to rely heavily on the results reached for other utilities by other regulators in other cases. (DEC Tr. vol. 11, 50, 116-17) Indeed, DEC witness Dylan W. D'Ascendis[97] incorporated authorized returns as a key factor for his Bond Yield Plus Risk Premium model. (DEC Tr. Vol. 11, 137-39) 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 p 2; Supplemental Rebuttal Exhibit DWD-5 p 2) As such, witness 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. (DEC Tr. vol. 17, 201) Historical

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[95] *Id.*
[96] *Cooper 2*, 367 N.C. at 443, 758 S.E.2d at 643.
[97] Testimony initially filed by Robert Hevert was adopted by witness D'Ascendis. (DEC/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. (DEC Tr. vol. 11, 142-45)

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. [98] (DEC Tr. vol. 16, 373-74)

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."[99] Efforts that arise from a desire to protect investors from swings in market prices are inappropriate.[100] Further, any concern that changes to the company's return should only be gradual is inconsistent with N.C. Gen. Stat. § 62-133(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."[101]

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[98] Witness D'Ascendis' analysis is also erroneous because it relies on projected bond yields, as well as current yields, driving the results up. (DEC/DEP Consolidated Tr. Vol. 6, 613, 615-16, 642)
[99] *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).
[100] *Public Staff 2,* 331 N.C. at 225, 415 S.E.2d at 361.
[101] N.C. Gen. Stat. § 62-133(e).

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 Tr. vol. 17, 229)

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. (DEC Tr. Vol. 11, 368-69; DEC Tr. vol. 17, 223-26) 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 DEC 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."[102] In its determination of a fair ROE, in particular, the Commission should consider and analyze a stipulated ROE "along with all the evidence regarding proper rate of

[102] *State ex rel. Utilities Comm'n v. Carolina Utility Customers Association* (*CUCA*), 348 N.C. 452, 466, 500 S.E.2d 693, 703 (1998) (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).

return" and adduce "its own independent conclusion as to the proper rate of return on equity."[103]

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 DEC are safe, conservative, and relatively stable investments. (DEC Tr. vol. 16, 382-87) Indeed, the impact of COVID on the required rate of return was addressed in supplemental testimony filed by two of the witnesses – AGO witness Baudino and Company witness D'Ascendis – and

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

neither changed his recommended ROE. (DEC Tr. vol. 11, 365; DEC Tr. vol. 16, 382.

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. (DEC Tr. vol. 16, 321-22, 327, 330; DEC Tr. vol. 17, 165) Value Line reported in January 2020 that cuts in interest rates by the Federal Reserve in 2019 reduced interest rates on already low fixed income investments, and “this made the dividend yields of electric utility equities relatively more attractive.” (DEC Tr. vol. 16, 331-32) Interest rates were already very low before 2019 and the rates have continued to drop.

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. (DEC Tr. vol. 16, 322-27) Even when the Federal Reserve pared back its Quantitative Easing policy and raised the funds rates, the 30-Year yield remained low. (DEC Tr. vol. 17, 97-100) In 2019, the Federal Reserve reversed course and cut rates again. (DEC Tr. vol. 16, 326; DEC Tr. vol. 17, 98) By December 2019 the yield on the 30-year Treasury bond was 2.30% and trending downward. (DEC Tr. vol. 16, 325) In February 2020 just prior to the outbreak of the pandemic, the yield was 1.97%. (DEC Tr. vol. 16, 383) The yield rose 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%. (Id.)

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. (DEC Tr. vol. 16, 383)

DEC's cost of debt has dropped. Company witness Karl W. Newlin testified that recent debt issuances for DEC cost 2.45% coupon rate for 10-year debt and 3.2% for 30-year debt, both substantially lower than DEC's embedded cost of debt, which is 4.27%. (DEC/DEP Consolidated Tr. vol. 1, 95; McManeus Second Settlement Exhibit 1 p. 2).

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

- DEC has an A1 rating from Moody's and an A- rating from Standard and Poor's (S&P's) with stable outlooks. (DEC Tr. vol. 16, 388)
- DEC 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. (DEC Tr. vol. 16, 332) Most had credit ratings of BBB/BBB+, and only about ¼ had a credit rating of A-.
- DEC'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 DEC's cost of equity should be higher than that of the proxy group. (DEC Tr. vol. 16, 378; DEC Tr. vol. 17, 92)

- DEC's ratings did not change between February and late June when the impact of COVID was analyzed in supplemental testimony. (DEC Tr. vol. 11, 365; DEC Tr. vol. 16, 382)

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. (DEC Tr. vol. 16, 384) The average beta for electric utility stocks rose substantially, also indicating increased riskiness. (DEC Tr. vol. 16, 389) (Beta is a measure of the riskiness of particular stocks relative to the overall riskiness of equities.) (DEC Tr. vol. 16, 342-43)) However the reliability of the beta factor has been questioned both by Company witness D'Ascendis (DEC Tr. vol. 11, 132-36) and by AGO witness Baudino (DEC Tr. vol. 16, 344), 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. (DEC Tr. vol. 16, 392) 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. (DEC Tr. vol. 11, 365; DEC Tr. vol. 16, 382)

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

		ROE	Note	DCF	DCF	CAPM	CAPM
Witness	Party			Range	Midpoint	Range	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	8.25% - 8.4%	8.33%	7.2% - 7.3%	7.25%
Note 1	See D'Asccendis Supplemental Rebuttal, Tr. Vol. 11, 344-45, Table 1, pre-filed 7/20/2020.						
Note 2	See Baudino Supplemental, Tr. Vol. 16, 389, Table 1, pre-filed 7/10/2020.						
Note 3	See O"Donnell Updated, Tr. Vol. 20, 135, Table 7, pre-filed 4/23/2020.						
Note 4	See Woolridge Supplemental, Tr. Vol. 17, 219, Table 1, pre-filed 2/18/2020 and updated 3/25/2020 for debt.						

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. (DEC Tr. vol. 16, 369-72; DEC Tr. vol. 17, 180-199; DEC Tr. vol. 20, 82-83)

DCF Analyses

A constant growth DCF analysis values a financial asset based on its ability to generate future net cash flows. (DEC Tr. vol. 16, 337) 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.[104] (DEC Tr. vol. 16, 337) The DCF approach was considered the most reliable method for measuring the cost of equity by witnesses Baudino, Woolridge, and O'Donnell. (DEC Tr. vol. 16, 362; DEC Tr. vol. 17,128; DEC Tr. vol. 20, 108) 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. (DEC Tr. vol. 17, 130; DEC Tr. vol. 20, 109-11) The model uses current stock prices that are verifiable and publicly available, offering the best indicator available of what investors require. (DEC Tr. vol. 16, 363) Analyst projections of earnings and dividend growth and historical measures of growth are also readily available. (DEC Tr. vol. 16, 363; DEC Tr. vol. 17, 137; DEC Tr. vol. 20, 115-19) 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. (DEC Tr. vol. 16, 364) 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. (DEC Tr. vol. 11, 267-68; DEC Tr. vol. 16, 364-66) However, as witness Baudino explained, it is reasonable to assume that markets are efficient and that investors have already taken into

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

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. (DEC Tr. vol. 16 pp 364-66)

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. (DEC Tr. vol. 16, 342) 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. (DEC Tr. vol. 16, 336, 344, 364-65; DEC Tr. vol. 17, 128; DEC Tr. vol. 20, 130-31)

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. (DEC Tr. vol. 16, 364-65) 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. (DEC Tr. vol. 16, 344) Witness D'Ascendis also expressed doubts about the CAPM due to concerns regarding the reliability of the "beta" factor to measure riskiness. (DEC Tr. vol. 11, 132-36) 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. (DEC Tr. vol. 16, 369) 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. (DEC Tr. vol. 16, 370) Another problem is that witness D'Ascendis' estimates of the overall market return are excessive, driving his results upward. (Id.) His ECAPM study - which was used to adjust the effect of the beta factor downward - further increased his results in his earlier study. (DEC Tr. vol. 16, 371-72)

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. (DEC Tr. vol. 16, 392)

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. (DEC Tr. vol. 11, 136-40) 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. (DEC Tr. vol. 16, 369-70) 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 I.A.[105] (DEC Tr. vol. 16, 373-74) 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.[106] First, it uses projected earnings for years well beyond the date rates will be effective in this case; i.e., the years 2022-2024. (DEC Tr. vol. 11, 140-41; DEC Tr. vol. 16, 375-76)[107] Second,

[105] *See* Part I.A.2; *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.
[106] 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.
[107] 2019 Piedmont Rate Order at 43.

the Commission has previously stated that it does not favor future projections based solely on analysts' earnings projections.[108]

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. (DEC Tr. vol.16, 375) 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. (DEC Tr. vol. 20, 131-32)

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.

[108] *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, (DEC Tr. vol. 11, 78-96) 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. (DEC Tr. vol. 17, 206-10)[109] With regard to the other factors, credit ratings take into account such business risks, and DEC has a strong credit rating. (DEC Tr. vol. 16, 378-79; DEC Tr. vol. 17, 211-12)

B. DEC 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.[110] 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. (DEC Tr. vol. 20,

[109] *Public Staff 2*, 331 N.C. at 221, 415 S.E.2d at 358-59.
[110] *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.

137) 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. (DEC Tr. vol. 16, 353, 382) That equity ratio is DEC's actual equity ratio in the 2018 test year, (id.) and is somewhat higher than the average of common equity ratios of the other companies in the proxy group, (DEC Tr. vol. 16, 35) Witnesses Woolridge and O'Donnell recommended use of a 50% equity ratio,[111] (DEC Tr. vol. 17, 118; DEC Tr. vol. 20 p 141) and, although witness Newlin testified that a 53% equity ratio should be adopted, he did not support this position with technical analysis. (DEC Tr. vol.16, 141, 353)

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 Carolinas' 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

[111] Witness Woolridge accepted the 52% equity ratio agreed to in the partial settlement. (DEC Tr. vol. 17, 228)

consumers when it considers what rate of return to establish pursuant to N.C. Gen. Stat. § 62-133(b)(4).[112]

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. (DEC Tr. vol. 16, 394)

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 $75 million would be shaved from DEC'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 $ 75 million addition to DEC's cost of service will be charged to DEC's North Carolina retail customers year after year.

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

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 (DEC Public Hearing Tr. vol. 1 – DEC Public Hearing Tr. vol. 4) 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. (DEC Public Hearing Tr. vol. 1, 19-23, 26-28, 33-34, 36-37; DEC Public Hearing Tr. vol. 2, 18-19; DEC Public Hearing Tr. vol. 3, 15-20, 30-36, 38-42, 56-57, 63-68, 74-77, 88-90; DEC Public Hearing Tr. vol. 4, 15-17, 24-26, 58-61, 71-76, 78-80, 83-84)

- 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. (DEC Public Hearing Tr. vol. 1, 26-27; DEC Public Hearing Tr. vol. 3, 17-20, 33-35, 38-39, 40-41, 63-64, 66-68, 75-77, 88-90; DEC Public Hearing Tr. vol. 4, 15-16, 58-59, 71-72, 75, 79, 84)

- Duke's proposal for grid improvement plan (GIP) should be denied. (DEC Public Hearing Tr. vol. 1, 17-18; DEC Public Hearing Tr. vol. 2, 13-14, 18-19, 30-31; DEC Public Hearing Tr. vol. 3, 44, 50-51; DEC Public Hearing Tr. vol. 4, 27-29, 31-32, 34-35)

- 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. (DEC Public Hearing Tr. vol. 1 – DEC Public Hearing Tr. vol. 4)

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, DEC's proposed rate of return and capital structure unnecessarily add more than $75 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 $75 million each year.

III. DEC SHOULD PROMPTLY RETURN TO RATEPAYERS OVER $1 BILLION 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.[113] As a result, DEC has accrued a large sum in federal and state deferred taxes that it no longer needs to meet its future tax liabilities. In addition, DEC has deferred revenues that were provisional and over-

[113] The Commission previously ruled that this general rate case would determine how DEC 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.

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 DEC at issue here that must be returned to customers, two of which are related to excess deferred income taxes (EDIT). EDIT represents monies DEC previously collected in rates to meet future tax liabilities that DEC 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 unprotected EDIT amounts to just over $1 billion. (DEC/DEP Consolidated Tr. vol. 4, 71)[114]
- Additionally DEC owes customers over $34 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. (DEC/DEP Consolidated Tr. vol. 4, 68-69) DEC owes its customers about $121 million for the deferred revenues. (DEC/DEP Consolidated Tr. vol. 4, 72)

[114] This issue does not relate to federal EDIT that is classified as "protected." For this EDIT, the federal tax code prescribes its return over a time period that mimics the life of the underlying assets. (DEC/DEP Consolidated Tr. vol. 4, 69, 105) The AGO does not contest the approach that returns protected EDIT through base rates.

DEC put into effect a temporary rate increase in August 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 DEC owes customers. (DEC/DEP Consolidated Tr. vol. 4, 73)

Instead of continuing that approach after final rates are approved in this case, however, DEC 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. (DEC/DEP Consolidated Tr. vol. 4, 73-74) The Public Staff agreed to that gradual approach in a non-unanimous stipulation entered 31 July 2020. (DEC/DEP Consolidated Tr. vol. 4, 73-74)

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

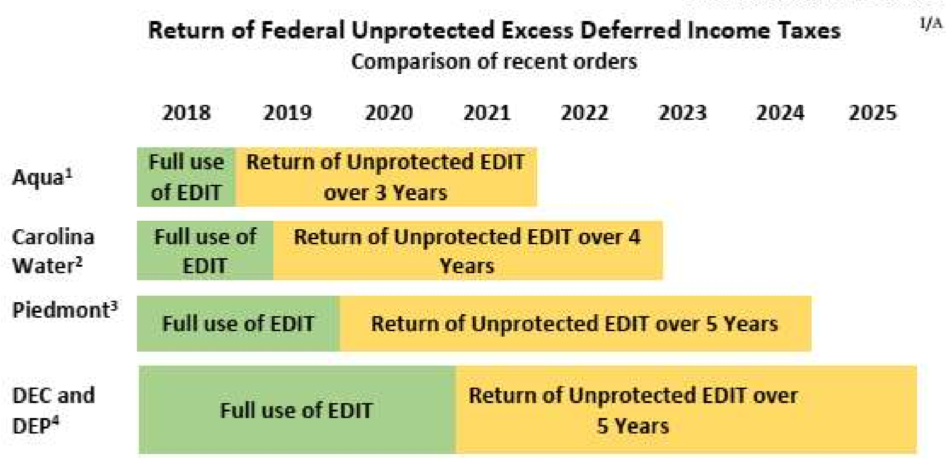
The Attorney General urges the Commission to require DEC to return all of the amounts to ratepayers over no more than two years. There is no dispute that the ratepayers are entitled to these monies. (DEC/DEP Consolidated Tr. vol. 4, 67) These amounts could be used to fully offset the rate increase that the Commission authorizes in the case for some time and thereby avoid increasing rates during an emergency pandemic. DEC 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.[115] Circumstances have not improved for customers, though, and the same offset

[115] Amended Motion for Approval of Undertaking Required by N.C. Gen. Stat. § 62-135(c) to Implement Temporary Rates, Subject to Refund, filed 4 August 2020, at 2.

approach is reasonable until the balances are fully returned. Alternatively, the Commission could decrease rates for a time to assist customers even further.

DEC'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, DEC will hold onto ratepayer money for many years without good reason, and DEC 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.

AGO McManeus/Smith Cross Exhibit 1



[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..

(AGO-McManeus Smith Cross Exhibit 1; DEC/DEP Consolidated Tr. vol. 4, 76-81) DEC'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 DEC has already had the full use of the funds for almost three years, which has provided considerable time for DEC 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 February, and is considerably shorter than DEC initially proposed. (DEC/DEP Consolidated Tr. vol. 4, 106) However, the improvement from DEC'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 recommended before the COVID-19 pandemic, and did not take into account the altered economic circumstances for many customers.

DEC argues that it is in ratepayers' interest for DEC 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. DEC (DEC Tr. vol.11, 392) Witness Newlin testified that DEC 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 DEC 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 DEC collecting from ratepayers now to prepay DEC taxes that will be due many years in the future. Under DEC's proposed revenue requirement, DEC will continue to collect $ 271.5 million per year for net income taxes. (McManeus Second Settlement Exhibit 1 p 1) However, DEC witness Steven Keith Young testified that DEC'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 DEC 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. DEC'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 DEC'S USE OF NONSTANDARD, OUTDATED TECHNOLOGY FOR CUSTOMER ACCESS.

DEC has invested in costly advanced meter infrastructure (AMI), i.e., smart meters and related facilities that have been installed for almost all retail customers in North Carolina. (DEC Tr. vol. 13, 139) These AMI investments replaced meters that could have been used for another decade or more.[116] Smart meters have advanced features that include the capability for two-way communications and detailed interval usage measurement, and DEC claims that the technology is "customer-focused," in that it "directly provides and enables greater convenience and transparency over a customer's energy consumption." (DEC Tr. vol. 13, 138, 140) However, the reasonableness of DEC's investment in smart meters was questioned in DEC's last rate case due to its high cost relative to the benefits offered to its customers.[117] (DEC Tr. vol. 11, 953)

The concerns about the reasonableness of the investment have not been adequately addressed by DEC. This is particularly true in light of decisions DEC has made that will limit customers' benefits even after DEC's new customer information system is operational. (DEC Tr. vol. 11, 974-75; AGO Hatcher Cross Exhibit 1 and 4)[118] The new customer information system, called Customer Connect, does not incorporate available advanced standard technology that

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[116] 2018 DEC Order 125, Clodfelter Dissent 58, Brown-Bland Dissent at 3-4.

[117] 2018 DEC Order at 76, 124, 127, Clodfelter Dissent 54-62, Brown-Bland Dissent at 3-4.

[118] 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.

facilitates access to data by customers and their authorized third parties. DEC 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 DEC.

In DEC's last rate case, some parties questioned the reasonableness of DEC's investment in AMI smart meters and Customer Connect unless customers will be able to access and use the very detailed data that DEC is collecting from the smart meters.[119] (DEC Tr. vol. 11, 951-53) Smart meters were deployed to work in tandem with the implementation of Customer Connect in order to improve customer service, [120] 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.[121] (DEC Tr. vol. 13, 138, 140)

The Commission concluded in the last rate case that DEC's 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. [122] 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

[119] 2018 DEC Order at 76, 126.
[120] *Id.* at 26.
[121] *Id.* at 76.
[122] *Id.* at 124.

usage at peak times and to save energy.[123] Further, DEC was notified that "DEC'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."[124]

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.[125]

The advantages of AMI and Customer Connect technologies for customers have yet to be realized in DEC's rate structures, but even when the structures are rolled out, they will not yield benefits for customers that take effective advantage of AMI data because DEC's implementation plan is designed in a way that limits convenient customer options to those offered by DEC. (DEC Tr. vol. 11, 974-75; AGO Hatcher Cross Exhibit 4 at 19-20)

Innovative programs and applications that would be accessible to DEC customers from authorized third parties will not be accessible for some time because DEC plans to integrate smart meters with Customer Connect using a non-standard outdated technology that is unique to Duke called My Duke Data Download. (DEC Tr. vol. 11, 968; 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. (Id.) If DEC's

[123] *Id.*
[124] *Id.*
[125] *Id.*

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. (DEC Tr. vol. 11, 968, 973) 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. (DEC Tr. vol. 11, 975; *see* AGO Hatcher Cross Exhibit 2) The choices available to DEC's customers will be effectively narrowed to programs offered by DEC, 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.)

DEC contends that it would be unreasonably costly to use Green Button Connect, but DEC's cost analysis indicates that the cost of the technology amounts to roughly $1.7 million over a period of five years for DEC and Duke Energy Progress. (DEC Tr. vol. 11, 970; AGO Hatcher Cross Exhibit 3 at 2) That is less than a percentage point of DEC's spending on AMI meters: the investment in 2016 was $73.9 million in North and South Carolina,[126] and DEC proposes to add another $128 million in this case. (DEC Tr. vol. 13, 140) It is also a small amount compared to DEC's investment in Customer Connect, which was $123.1 million as of the last rate case. (DEC Tr. vol. 11, 972)

[126] Duke Order at 117.

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 DEC. DEC'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 DEC's own programs that allow customers to view and download usage information from DEC's website in a standardized format. (AGO Hatcher Cross Exhibit 3 at 1; AGO Hatcher Cross Exhibit 4 at 21) DEC'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, 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 DEC – options developed for wide use that are innovative, advanced, and frequently updated.

Because of the limitations built into DEC's plan for implementing Customer Connect, DEC 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 April 2021, and changing the implementation plan to incorporate the standard will set back the completion of Customer Connect. (DEC Tr. vol. 11, 965; AGO Hatcher Cross Exhibit 1 at 5-6; AGO Hatcher Cross Exhibit 4 at 19-20) Thus, DEC 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 DEC's large investment in AMI meters are still not proven and the potential has been limited by DEC's implementation of Customer Connect.

These limitations that have been built into DEC'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 DEC 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.

(DEC Tr. vol. 11, 899, 950-51)

Based on these facts, DEC 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 DEC has built into its system; these restrict the availability of emerging technologies and stymie customer access to new programs and applications. DEC 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, DEC 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 DEC'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 DEC's rate of return to the lower level that is cost-justified according to market data. In addition, DEC should promptly return over $1 billion to ratepayers that DEC holds relating to tax changes that occurred several years ago. Finally, DEC 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 DEC;
- Limit DEC'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 DEC's excess deferred taxes and other tax-related deferred amounts to ratepayers as soon as possible; and
- Direct DEC 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 of November, 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 November 2020.

__/s/______________________
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