on June 19, June 26, July 3, and on July 30, 2014. Id. at 93-110. Even though the coal-fired units at the Lee Plant were scheduled for retirement in the fall of 2014, and planning work was underway for the much larger effort required to decommission those units and the active waste ash impoundment, it was clear that in April and May, 2014, the situation involving the piping underneath and associated with the closed 1951/1959 basin, had become a central focus of attention. This interest is of significance since the inactive ash basin was not at that time subject to South Carolina's dam safety regulations or any other regulatory regime relating to waste surface impoundments. Likewise, the "ash fill" or "borrow area" was not subject to any permit requirements or to any generally applicable regulation at the time. As it turns out, the inactive ash basin was not, and is not, subject to the EPA's CCR Rule, and, of course, it is not subject to North Carolina's CAMA. I also note that there is no evidence in the record that, during this time, either the inactive ash basin or the "borrow area" were causing, or were otherwise associated with any groundwater or surface water contamination on or in any area surrounding the plant site, including the Saluda River.

Following this sequence of events, on July 17, 2014, DHEC tendered to the Company a draft consent agreement which required the Company to develop and then to implement a remedial plan for the inactive ash basin. See Kerin Rebuttal Public Staff Cross Ex. 4 (Ex. Vol. 24, Part 2, pp. 171-185). This draft consent agreement did not specify the work to be performed by the Company nor did it establish any timetable for that work but, instead, established a procedure for DHEC review, oversight, and approval of whatever work the Company proposed to undertake. The draft stated as a conclusion of law, not supported by any findings of fact whatsoever, that a release or threat of release of hazardous substances had occurred from the inactive ash basin in violation of the federal Comprehensive Environmental Response, Compensation and Liability Act of 1980[16], notwithstanding the fact that coal ash wastes were not themselves classified as "hazardous" for purposes of the Resource Conservation and Recovery Act,[17] or the fact that there was at that time no evidence of any contamination of soils, surface water, or groundwater that could be associated with the inactive ash basin. Id. The draft simply recited that: "Duke Energy is entering into the Consent Agreement out of concern for human health and the environment and will take all necessary steps in compliance with all environmental laws to prohibit future releases from the Site." Id. at 175.[18] Based on the structure and content of the draft agreement between DHEC and the Company and the testimony from both the Company's witnesses and from Public Staff witness Garrett, who has had extensive experience dealing with DHEC in regards to coal ash surface impoundments, I find that it is more likely than not that DHEC lacked any legal basis to impose the consent agreement in the absence of the Company's acquiescence.

[16] 42 U.S.C. §§ 9601-9675.

[17] 42 U.S.C. §§ 6901-6992k.

[18] The draft July 17, 2014 consent agreement contains no findings that there had been any *past* releases.

According to the testimony from witness Kerin, on September 29, 2014, the Company and DHEC entered into a revised consent agreement that required immediate excavation of the inactive ash basin and removal of the ash therein and, additionally, excavation and disposal of the ash in the unregulated borrow area, with all such activity to be completed by December 31, 2017.[19] Tr. Vol. 15, pp. 121-123. Throughout the period leading up to September, 2014, the evidence is clear that both the Company and DHEC were focused on the issue of the corrugated metal pipe running under the inactive ash basin and on the status of the two discharge pipes. For reasons that will be discussed presently, it is significant that the communications during this time period contain no indication that either the Company or DHEC were concerned about the structural integrity or stability of the inactive ash basin's dike. With respect to the impounding dike, all attention was focused on whether the level of the dike should be raised in order to prevent stormwater overflows after plugging of the discharge pipes.[20]

The Company's plan for closure of the active primary and secondary ash basins was to construct a new, on-site lined landfill within the footprint of the secondary basin, to dewater the ash in the basins, and then to excavate the ash and move it to the new on-site landfill. This new landfill would have sufficient capacity to accommodate not only the ash quantities in the active primary and secondary basins, but also the quantities that were contained in the inactive ash basin and the borrow area. Tr. Vol. 21, pp. 24-25. This fact is not disputed by the Company. However, because of the strict timetable established in the September 29, 2014, agreement, the Company concluded that it would be unable to wait for construction of the new on-site landfill before relocating ash from the inactive basin and the borrow area and, instead, needed immediately to excavate the unregulated, closed, inactive ash basin and the borrow area, and then to transport the wastes to an offsite third-party landfill in Homer, Georgia. **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]**

Based on this evidence and on the testimony by witnesses Kerin and Garrett, I conclude that DHEC's and the Company's insistence on immediate excavation and removal of the ash in the inactive ash basin and in the borrow area was a direct and proximate result of the ash spill at the Company's Dan River Plant in February, 2014. I base this on the following factors, among others: (1) that both the inactive ash basin and the borrow area were unregulated, were not subject to any permit requirements or outstanding directives, and did not later become subject to the federal CCR Rule; (2) that

[19] The revised consent agreement, executed on September 29, 2014, was not put into the record in this proceeding by any party, but I have accepted the testimony of witness Kerin as to its contents and substance. It marked a significant change from the July 17, 2014 draft consent agreement, a matter which is not further explained in the record of this proceeding.

[20] Also of interest here are Junis Exs. 14, 15 and 16 (Ex. Vol. 26, Official Exhibits-Public Staff Junis Exhibits 13-23, pp. 9-24) which are a series of communications between the Company and DHEC in the first half of 2014 concerning compliance issues relating to the two active impoundments at the Lee Plant. Among other topics discussed in the communications are the stability of the dams and embankments for the primary and secondary ash ponds and the potential for liquefaction of soils in the event of an earthquake. These communications do not discuss any issues relating to the inactive ash basin or the borrow area.

the inactive ash basin was not subject to South Carolina's dam safety law; (3) that no concern appears in the record concerning any aspect of either the integrity of the inactive basin dike, the discharge pipes, or the corrugated metal stormwater pipe under the basin until immediately after the Dan River spill; (4) that as witness Kerin testified and as the correspondence reveals, the Dan River incident and, more particularly, the risk of failure of corrugated metal piping under the basin was a specific topic of concern to DHEC and was the focus of the parties' attention in the months following the Dan River spill[21]; and (5) that DHEC initially sought to assert regulatory control over the basin through a statute clearly inapplicable to it, evidencing the pressure it was placing on the Company to address its concerns about the basin. I note that none of this history leading to the Company's agreement to commence immediate excavation of the inactive ash basin and the borrow area is discussed in the majority's analysis of this issue.

The Company, seeking to avoid a finding that the Dan River incident was the principal driver of the September 29, 2014, agreement, contends that immediate excavation and removal of the ash from the inactive ash basin was necessary in order to avoid the risks of sloughing of the impoundment dike or, more severely, liquefaction of the soils underneath the dike structure in the event of a major earthquake, and that removal of the ash from the basin would eliminate any concern about a release of ash into the Saluda River in such event. Witness Kerin testified to the point as follows:

> The S&ME report had some recommendations on how do [sic] deal with the steep slopes and how to deal with some stabilization of the dam, but if you think of liquefaction, there is no way to solve liquefaction from a dam modification issue. Liquefaction is the underlying soils below the dam. So those soils were alluvial, which is based on being beside that river over the years. You put that on top -- there was sandy soils, so our core borings indicated that the base of that dam was very susceptible to liquefaction even [sic]. So if you think of what liquefaction is, you take the sand, the ash, you shake it, it basically liquefies and it will move. So the concern here was, below that dam, the base of that dam right along the Saluda River, and that is right -- if you are familiar with that dam, the toe of that dam is on the river -- that any earthquake even or severe shaking of that would cause that earth to liquefy and you would lose the contents. Very similar to what happened in the TVA event, when their dam, the surfaces below, liquefied in Kingston.

Tr. Vol. 15, p. 118.

There are significant discrepancies between the conclusion that the Company wishes the Commission to draw about its decision in 2014 to proceed immediately to excavate the inactive ash basin and the borrow area, and the documentary evidence in the record. These discrepancies are so great that I conclude that the Company's theory is an after-the-fact rationalization, and that based on the evidence of what the Company

[21] In particular, see Tr. Vol. 24, pp. 152-155, where witness Kerin testified that based on reports from his superior, John Elnitsky, who attended meetings with DHEC, the Dan River incident and the similar drain pipes under the Lee Plant basins were a primary focus of DHEC's concerns.

knew, did, and said at the time in 2014, its decision to commence immediate excavation and removal was not based on a concern about the structural integrity of the dike at the inactive basin in the near or intermediate term or the possibility that a seismic event would occur.[22] I summarize these discrepancies in the following itemized points:

1. In response to a pre-hearing data request to the Company submitted by the Public Staff, which requested documents upon which the Company relied in concluding that there were unacceptable risks associated with leaving ash in the inactive ash basin until such time as the new onsite landfill was completed and the ash could then be removed to that new landfill, the Company produced an engineering report and analysis by URS Corporation, dated June 30, 2015 (URS Report). See Garrett Duke Cross Ex. 1, Tab 20 (Ex. Vol. 22, pp. 137-232). More will be said about this report presently. For now I note only that the report proffered by the Company was dated some eight months after the Company had already entered into its September 29, 2014, consent agreement with DHEC and over a month after the Company had already begun excavating the inactive ash basin and transporting the ash offsite. The Company had already made its decision and begun to take action before the URS Report was delivered.[23]

2. The URS Report assessed not only the inactive ash basin and the borrow area, but also the two active surface impoundments. First, among the key findings in the report's executive summary were the following:

   > Imminent Dam Safety Issues: No conditions were observed or identified by analyses completed under Phase 2 that represent a dam safety condition requiring immediate attention.

   Id. at 143.

   Among the other key findings were that the alluvial soils and ash of the inactive basin could be susceptible to liquefaction during the maximum design event earthquake and could be unstable following such an earthquake, and this was the subject to witness Kerin's testimony, as quoted above. *This exact same finding was made in the URS Report with respect to both the active primary and secondary ash basins,* which noted that "for the primary ash pond that is near the design normal pool elevations, it is possible that portions of the pond could breach, releasing its contents." Id. at 209. These identical findings are significant because the Company has contended that it could not responsibly carry the seismic risk identified in the URS Report for the seven-year period

[22] It should not escape notice that there were then, and have been since, no identified structural risks associated with the unregulated borrow area, but the Company also committed in 2014 to immediately excavate and transport for offsite disposal of the ash in the borrow area.

[23] Ex. Vol. 22, pp. 138-232.

required to construct its new onsite landfill and that, therefore, it was necessary to commence excavation and removal of ash from the unregulated inactive ash basin and the borrow area immediately. Yet the Company considered that very same risk to be acceptable with respect to the wastes that would remain in the primary and secondary ash basins until such time as the new onsite landfill was constructed and available for use, notwithstanding that the URS Report identified geotechnical stability and performance issues for the primary ash basin that were as significant as any that were identified relative to the inactive ash basin.[24]

3. The URS Report notes, on page 5, that URS had not done a more detailed analysis of the liquefaction potential for the inactive ash basin due to the fact that ash removal from the basin was already underway, rendering further analysis unnecessary.

The URS Report was preceded by a report prepared by the Company's engineering consultant, Soil & Materials Engineers, Inc. (S&ME), dated September 12, 2014 (S&ME Report), which was only a couple of weeks before the Company committed to immediate excavation and removal of ash from the inactive ash basin and the borrow area. Garrett Direct Ex. 2 (Ex. Vol. 22, pp. 6-43). This S&ME Report is not discussed by the majority in its analysis. The S&ME Report included field and laboratory testing and modelling of both slope stability of the dike and liquefaction potential of the underlying soils in the event of a major earthquake (modeled using a magnitude 7.3 on the Richter Scale, which was the magnitude of the 1886 Charleston earthquake).[25]

The S&ME Report recommended that the Company continue to monitor the basin embankments to observe and detect any changing conditions. It noted that the addition of rip rap material along the river bank would alleviate any short-term risks of surface erosion and shallow sloughing due to river flow along the base of the embankment. The S&ME Report further recommended that *if* the Company wished to improve slope stability beyond the existing case, it could undertake to buttress or to flatten the slopes of the embankment, but S&ME did not go so far as to find that the existing condition of the slope was unacceptable. In response to a data request from the Public Staff, the Company admitted that S&ME had not recommended immediate excavation of the inactive ash basin, and that it had provided specific instructions on how to undertake any *optional or elective* changes to the embankment that the Company wished to make. See DEC's

[24] Of course, since the coal units at the Lee plant had been retired in November, 2014, the Company cannot explain this difference by pointing to a need to continue to use the primary ash basin to sluice and store new ash wastes from ongoing and future operations.

[25] The majority states that witness Garrett's proposal that the Company should have delayed excavating the inactive ash basin until the new onsite landfill was available "…would have required trading old risks for new risks." Majority Order at 309. But the "risks" considered in the S&ME Report were not new ones – they had been present since the closure of the inactive ash basin in 1977. As the S&ME Report explicitly noted, the actual historical performance of the dike was a factor to be considered in assessing whether any remedial action was required or was desirable, and that engineering standards for new dikes or impoundments were not necessarily a reliable guide for evaluating existing impoundments with an extended history of actual operation.

Response to Public Staff Data Request No. 58-22, pp. 1-5 (March 23, 2018) (filed as a late-filed exhibit pursuant to my request and the request of Commissioner Brown-Bland, which were made on the record during the evidentiary hearing).

The S&ME Report represents the state of the Company's knowledge at the time it concluded that it would commence immediate excavation and offsite disposal of the contents of the inactive basin, and there is nothing in the S&ME Report that suggests an immediate or near-term risk of any release of materials into the Saluda River while awaiting construction of the new onsite landfill.

Public Staff witness Garrett concurred in the Company's decision to excavate the inactive ash basin and remove its contents to the new onsite landfill at the time it was completed, and I do not take issue with this portion of his analysis. He disputes only the timing of the Company's decision, which necessarily required more expensive transportation and offsite disposal. The majority takes the testimony of witness Kerin, who in period April to September, 2014, was brand new to the coal ash arena and had no first-hand knowledge and minimal prior pertinent experience, at face value. I find, on the other hand, that the testimony of Public Staff witness Garrett, who had first-hand experience in a number of coal ash projects in South Carolina and had negotiated extensively with DHEC, is far more credible on the matters in dispute. See Tr. Vol. 21, pp. 16-17 (setting out witness Garrett's specific experience with ash impoundment closures in South Carolina).

Based on all of the foregoing, I find that the Company's decision to commit in 2014 to immediate excavation and removal of the ash in the inactive ash basin and the borrow area at the Lee Plant was a direct consequence of the atmosphere created by the Company's imprudent management of the impoundments at the Dan River Plant, and was not due to any then-existing concerns about the integrity of the embankment of the inactive basin itself. **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]**

(ii) Dan River Steam Station

The three coal-fired generating units at the Dan River Steam Station (Dan River Plant) were retired in April, 2012, and the process of decommissioning the plant commenced thereafter. Associated with the coal units were two surface impoundments, known as the "primary pond" and "secondary pond," and two areas where dry waste ash had been placed, known as "fill area 1" and fill area 2," respectively. The Company had been anticipating and planning for retirement of the coal units at the Dan River Plant since at least 2008. E.g., Kerin Direct Public Staff Ex. 2, Part 2, pp. 49-53 (complete copy filed in the record by Public Staff March 19, 2018, pursuant to Commission request during the evidentiary hearing).[26] Even earlier, in its 2003 Coal Combustion Ten-Year Plan (2003 Plan) the Company had planned for the management of the ash waste storage and disposal areas in order to maximize use of available land on the plant site. Kerin Direct

[26] References to this exhibit hereafter are to the complete copy of this exhibit filed by the Public Staff as a late-filed exhibit on March 19, 2018.

AGO Cross Ex. 1 (Ex. Vol. 16, Part 2, pp. 123-280). The 2003 Plan concluded that the Dan River Plant had adequate ash waste storage area for at least another twenty years in either greenfield or brownfield disposal cases. The 2003 Plan contemplated a series of measures to provide long-term capacity involving excavating ash from the surface impoundments and then stacking the excavated ash in the two ash fill areas, thereafter covering the fill areas with synthetic caps. See, e.g., Kerin Public Staff Cross Ex. 6 (Ex. Vol. 16, Part 3, pp. 1-49). Total projected spending on these projects through 2013 was estimated to be $1,150,000 in capital costs, and approximately $5,700,000 for operating and maintenance costs.

The Company's 2008 Coal Combustion Products Ten-Year Plan (2008 Plan) continues the operating plan laid out in the 2003 Plan – periodic excavation of the two impoundments in order to preserve capacity followed by stacking the excavated ash in the two ash fill areas. The 2008 Plan noted that due to the plant's planned retirement schedule, conversion to dry ash handling and disposal, a topic considered in the 2003 Plan, would not be pursued. Kerin Direct Public Staff Ex. 2, Part 2, p. 55. At the time, the 2008 Plan contemplated that the ash fill areas would be capped with a synthetic cap and closed in 2011, and contained an estimated project budget for this activity, although it noted that the timing of that project might be re-evaluated depending on the actual plant closure date. Id., p. 142.

As far as the record discloses, when the coal units at the Dan River Plant were retired in 2012, nothing was done immediately to start the process of dewatering the two surface impoundments, notwithstanding the fact that the Company knew that dewatering was the single most important early step to be taken in order to eliminate or reduce the hydraulic pressure of the standing and interstitial water in the basin, and thereby reduce seepage and migration of ash constituents to surface water and groundwater. E.g., Tr. Vol. 15, pp. 33-74.[27] At the time of the February, 2014 ash release into the Dan River, dewatering of the impoundments still had not taken place. Nothing had been done to relieve the hydraulic pressure in the impoundments on the pipes that ran underneath them. The record discloses no external obstacle standing in the way of the Company's taking action to commence dewatering of the ash basins after 2012. The delays were all internal.

On January 22, 2014, a matter of days before the release of ash from the primary pond, the Company received a draft design report from its contractor AMEC Environment & Infrastructure, Inc. detailing the proposed closure of the surface impoundments

[27] Of interest on this point is an undated internal Company document titled "Ash Basin Closure Strategy." AGO Late- Filed Ex. 1, Tab E (filed as part of the evidentiary record on April 18, 2018, and subsequently accepted into the evidentiary record by Commissioner Order dated April 27, 2018). Internal evidence indicated that the document was most probably prepared sometime in 2013. Discussing "timing considerations" relating to ash basin closures the document notes: "[d]ewatering the ash basin in accordance with the NPDES permit will over a relatively brief time reduce and/or eliminate seepage which the company is currently addressing." Id. Addressing the Court at the sentencing hearing in the Company's criminal case, Company counsel stated: "The thing about seeps is that the easiest way to control a seep is to let us dry out the coal ash and move it and close those basins." Ex. Vol. 16, Part 3, p. 253.

(January 2014 AMEC Plan). Kerin Public Staff Cross Ex. 6 (Ex. Vol. 16, Part 1, pp. 111-137). The proposed closure design was described as follows:

> The preferred closure concept is the hybrid approach described as follows: move all Primary and Secondary Pond ash into the Ash Fill 1 and 2 area; close Ash Fill 1 and 2 in place with an engineered cover system; remove Primary and Secondary Pond embankments and re-use the soil for cover system construction and pond area restoration; grade the ash pond areas to promote drainage and stabilization; and remediate groundwater (either passively or actively) and implement long-term groundwater monitoring.

Id. at pp. 118-119. This closure concept had been prefigured in the Company's operating plan for the waste units at Dan River as set forth in the 2008 Ten-Year Plan. In the Company's internal planning documents, this "hybrid approach" was sometimes referred to as a "brownfield" strategy, both terms referring to the construction of a new landfill disposal facility over top of or within the perimeter of an existing area of ash fill, capping the existing fill area in place and using the newly constructed landfill for future waste disposal or for relocation of existing waste from other storage areas. It is contrasted with a "greenfield approach," which referred to the construction of a new landfill on land not previously used to dispose of wastes. The January 2014 AMEC Plan concept design plan was consistent with the manner in which the Company had been operating and managing the impoundments since at least the time of the 2003 Ten-Year Plan.

By April 28, 2014, less than two months after the February, 2014 release into the Dan River, focus had shifted from the preferred concept in the January 2014 AMEC Plan. On that date AMEC submitted to the Company a second report evaluating various possible locations for an *off-site* "greenfield" landfill for disposal of the waste ash from the Dan River Plant. See Kerin Public Staff Direct Ex. 7 (Ex. Vol. 16, Part 1, pp. 138-75). By November 13, 2014, the Company had submitted to the North Carolina Department of Environmental Quality (DEQ)[28] what became, in concept, the closure plan for which the Company now seeks cost recovery in this case. Id. at 176-99. That plan, in pertinent summary, provides for removal of the ash in fill area 1, for transportation and offsite disposal of that ash followed by construction of an on-site lined landfill within the footprint of ash fill area 1. The ash waste in the two impoundments, after first being dewatered, would then be excavated and permanently disposed of in the newly constructed onsite landfill. This plan differed from the January 2014 AMEC Plan in one critical respect – the January 2014 AMEC Plan did not contemplate excavation and offsite disposal of the ash from ash fill area 1 prior to construction of a new landfill in that location.

At the hearing in this case, Company witness Kerin and Public Staff witness Moore vigorously debated the possibility that the Company could have constructed a new lined landfill on another portion of the plant site (a "greenfield" site), and thereby avoided the costs incurred to excavate, transport, and dispose of offsite the ash in fill area 1. I do not

[28] Formerly known as the North Carolina Department of Environment and Natural Resources (DENR). DENR's name changed to DEQ effective September 18, 2015.

find it necessary to resolve that disagreement. Instead, I conclude that but for certain provisions contained in CAMA that were, I believe, directly connected and causally related to the Dan River ash spill in February, 2014, the Company would have been able to implement the January 2014 AMEC Plan, thereby avoiding the excavation, transport, and offsite disposal of the ash in fill area 1. I arrive at this conclusion based on the considerations set forth hereafter.

The bill that eventually was enacted as CAMA was originally filed on May 14, 2014, as S. 729, bearing the short title "Governor's Coal Ash Action Plan."[29] Section 10 of the bill singled out two of the Company's coal-fired generating plants, Dan River and Riverbend, and required prompt submission of closure plans for the surface impoundments at those plants and for permanent disposal of the ash in a lined structural fill, a lined landfill, or an alternative approved by DEQ. Dan River and Riverbend were the only two plants in the Company's fleet called out by name in the proposed legislation. The first edition of the filed bill contained recitals specifically referring to the Dan River Plant ash release and the fact that wastes from the release had settled into river bottom sediments, requiring extensive remediation.

The bill took substantially its final form in the Second Edition, which was adopted by the Senate Agriculture, Environment and Natural Resources Committee on June 17, 2014. All recitals in the original bill were dropped; however, the specific provisions targeting the Company's Dan River and Riverbend plants were retained in modified form. In all material respects for purposes of the present discussion, the bill remained unchanged thereafter until its enactment with an effective date of September 20, 2014. N.C.S.L. 2014-122.

CAMA contains a comprehensive scheme for regulation and eventual closure of all waste ash surface impoundments grounded on a risk-based priority classification – low, intermediate, and high – with the requirements for operation and closure, and the associated deadlines, increasingly stringent as the risk classification level increases. The determination of risk classification is to be made by DEQ on a site-by-site basis, based on extensive analysis and public input, except in four cases. In those four specific cases, the General Assembly pre-empted the general statutory scheme and declared that those sites were to be classified as high-priority sited and imposed a final closure date for the coal combustion residuals impoundments at those plants of August 1, 2019.[30] Those four sites, out of the entire fleet of the two Duke Energy affiliates operating in North Carolina, were Dan River, Riverbend, Asheville, and Sutton. All other sites were declared intermediate-risk for interim purposes with final risk classification to be established by DEQ later. The record in this case establishes that all of the Company's remaining waste surface impoundments were ultimately classified by DEQ as low-risk under CAMA. Tr. Vol. 16, pp. 38-42.

[29] N.C. Gen. Assembly, S. 729. Reg. Sess. 2013-2014 (2014). The complete legislative history of S. 729 is available at https://www2.ncleg.net/BillLookup/2013/S729.

[30] N.C.S.L. 2014-122, § 3.(b).

The most significant features of the final low-risk classification of the waste impoundments at the Company's other plants are an extended target date for final closure in 2029 and the potential opportunity to use a cap-in-place closure strategy for the impoundments, that being the same closure strategy for which the Company had been planning and preparing since the mid-2000s. In other words, as CAMA is now being implemented, the Company's pre-CAMA preferred closure strategies are still potentially available for all of its plants, except Dan River and Riverbend.[31]

Based on the entire record, I conclude that the General Assembly's pre-emption of the general regulatory regime and its peremptory directive concerning closure of the impoundments at the Dan River Steam Station was a direct consequence of the Company's February, 2014 ash release into the Dan River. The General Assembly's action in this regard cannot be based on any other factors evidenced in this record that differentiate the Dan River impoundments from those at the Company's other coal-fired generating plants.[32] The extensive evidence presented by the Public Staff and other intervenors concerning seeps and groundwater exceedances at all of the Company's plants does not show any evidence of environmental compliance issues, groundwater exceedances, seeps, or other environmental contamination associated with the two Dan River impoundments that are materially greater than or different from those at any of the Company's other plants. <u>See, e.g.</u>, Ex. Vol. 26, p. 61; Ex. Vol. 16, Part 2, pp. 35-80; Wells Public Staff Cross Ex. 2, p. 4 (complete copy filed on April 5, 2018, pursuant to the Commission request's on the record during the evidentiary hearing); Kerin Sierra Club Cross Ex. 2; AGO Late-Filed Ex. 1, Tab K.

Several intervenors and the Company have wrestled over whether or not the entirety of CAMA can be attributed to the Dan River ash release. I do not take a side in that debate but instead reach a more limited conclusion here – that based on the internal structure and history of the legislation that became S.L. 2014-122, certain of its specific provisions *can* be directly linked to the February, 2014 ash release at Dan River. It is the consequences following from those specific provisions that occupy me here.

The legislative dictate that Dan River Plant impoundments be treated as "high-risk" had substantial and costly consequences for their method of closure. The Company's pre-spill closure design concept, which was consistent also with the operating history of

[31] A high level summary description of the Company's pre-CAMA closure strategy for its ash basins is provided in Doss AGO Cross Ex. 1 (Ex. Vol. 12, pp. 818-839.) More detailed discussion of the Company's pre-CAMA closure strategies are contained in several of the documents referred to in Section I.C. hereafter.

[32] From the record presented it is not possible to draw a firm conclusion as to the rationale for the "high risk" designation of the Riverbend plant. Certainly, that designation cannot be attributed to the ash release at the Dan River plant in February, 2014, and the Company's mismanagement of the impoundments at Dan River. At the time CAMA was enacted the Riverbend plant was, however, subject to two pending suits alleging environmental contamination at the plant associated with waste ash impoundments, one in Mecklenburg County Superior Court brought by DEQ and the Southern Environmental Law Center and one pending in the United States District Court for the Western District of North Carolina brought by the Catawba Riverkeeper. See Junis Exs. 17 and 18 (Ex. Vol. 26, Official Exhibits-Public Staff Junis Exhibits 13-23, pp. 25-34.)

the impoundments, had been to consolidate the ash contents from the two impoundments in the unlined ash fill areas and then to cap the combined ash from the fill areas and the impoundments with a synthetic seal and a vegetative layer. This was not only the least cost closure method; it also could be implemented on a reasonably short schedule once the surface impoundments had been dewatered. (For estimates of cost and time to closure, see AGO Late-Filed Ex. 1, pp. 135-165, Tab J: Plant Demolition and Retirement Presentation for the Executive Governance Committee, dated October 14, 2013. Dan River ash basin closure costs commencing 2013 and concluding 2017 estimated to total $23,993,000.) Of course, we know now that the Company delayed commencement of ash basin closure from the proposed 2013 start date. We also know that the Company's total cost estimate for closure of the Dan River impoundments, not including inflation costs, are now estimated to be in excess of $222,994,117. See Revised Kerin Ex. 11 (March 22, 2018).

CAMA's high-risk classification of the Dan River Plant impoundments foreclosed the Company's earlier preferred closure plan because of two of the law's provisions. Section 3.(a) of CAMA would have permitted the Company to construct a new coal combustion residuals landfill on top of either of the two ash fill areas and then to remove the ash wastes from the surface impoundments for disposal in the newly constructed landfill. Such a new landfill would have required a liner system over the existing ash and one beneath the ash excavated from the impoundments and placed in the new landfill. The closure options permitted under Section 3.(a) of CAMA, however, do not include excavation of the ash from the two impoundments, and then consolidation of the fill ash and the excavated impoundment waste ash *in situ* with a final cover or cap over the combined waste but without a liner under the ash.

Although as just noted Section 3.(a) permitted the Company to construct a new, lined landfill on top of the ash fill areas, Section 5.(a) of CAMA placed a moratorium on the Company's ability to construct any new landfill on the site of ash fill area 1, meaning that the Company could not immediately begin the process of constructing a landfill in or over ash fill area 1 until that moratorium expired.[33] As witness Kerin testified, the moratorium caused considerable anxiety about the Company's ability to meet CAMA's August 1, 2019 deadline for final closure of the surface impoundments at Dan River Plant.

The moratorium only applied to new "coal combustion residuals landfills," which were landfills constructed on top of areas presently or previously used for coal ash waste storage or disposal, meaning that the Company was free during the period of the moratorium to explore options for construction of a new landfill on a "greenfield" site. During the period between February 2, 2014, and November, 2014, when the Company submitted its proposed action plan to DEQ, the Company did investigate and consider its "greenfield" options. I concur in the majority's findings that neither the Hopkins tract, which was investigated by the Company, nor an onsite area west of the existing plant, recommended by Public Staff witness Moore, were reasonably available alternatives and

[33] The moratorium was to expire and did expire on August 1, 2015, pursuant to Section 5.(c) of CAMA. N.C.S.L. 2014-122, § 5.(c).

that the Company acted prudently in declining to pursue these "greenfield" options. This does not, however, explain why the Company commenced immediate excavation and offsite disposal of the wastes in ash fill area 1, an area that was not itself subject to CAMA's requirements nor to the (at that time pending) CCR Rule. The Company cannot defend this decision on the grounds that excavation and offsite disposal of the ash from fill area 1 allowed it to move forward more rapidly with construction of a new onsite landfill. Excavation of ash fill area 1 did *not* exempt an attempt to construct a new landfill in that area from the moratorium imposed by Section 5.(a) of CAMA. This is so because "coal combustion residuals landfills," whose construction was subject to the moratorium, were defined in G.S. 130A-290(a)(2c), as that statute was amended by CAMA, to mean:

> ...a facility for the disposal of combustion products, where the landfill is located at the same facility with the coal-fired generating unit or units producing the combustion products, and where the landfill is located wholly or partly on top of a facility that is, *or was,* being used for the disposal of such combustion products, including, but not limited to, landfills, wet and dry ash ponds, and structural fill facilities.

(emphasis added.) Excavation of ash fill area 1, an unregulated facility, did not accelerate the Company's ability to construct a new landfill on that area and did not, therefore, enhance its ability to meet CAMA's mandated final closure deadline of August 1, 2019.

Nor was excavation and offsite disposal of the ash in fill area 1 necessary in order to enable the construction of a new landfill in that area. Again, Section 3.(a) of CAMA permitted the excavation and disposal of ash wastes from the two surface impoundments in a new "coal combustion residuals landfill," which as noted in the definition quoted above, is a facility located "...wholly or partly on top of a facility that is, or was, being used for disposal ..." of waste coal ash.

From a close review of witness Kerin's testimony, I conclude that the Company's decision to commence immediate excavation and offsite disposal of the wastes in ash fill area 1 was not based on any consideration of least-cost options, was not dictated by CAMA, was not required in order to enhance the Company's ability to comply with CAMA, and did not in fact accelerate the construction of a landfill within the footprint of ash fill area 1. Instead, I conclude from the testimony that the Company's actions were in fact driven by the pressure it felt in the aftermath of the Dan River release to, put in the vernacular, "do something, do anything, just do something." Tr. Vol. 25, p. 27-28; Tr. Vol. 7, pp. 13-15. My conclusion is further confirmed by the fact that the internal processes for bidding and contracting for excavation and offsite disposal of the ash from the Dan River ash fill commenced in July, 2014, and bids were in hand by October 9, 2014. Kerin Direct Public Staff Direct Ex. 5 (Ex. Vol. 16, pp. 111-113). This time period coincides with the movement of S. 729 through the legislative process, and it *precedes* the Company's submission of its excavation plan for Dan River to DEQ on November 13, 2014. Kerin Direct Public Staff Cross Ex. 9 (Ex. Vol. 16, pp. 181-203).

In consideration of the foregoing, I would deny the Company's request to recover **[BEGIN CONFIDENTIAL] [END CONFIDENTIAL]** spent for excavation, transport, and offsite disposal of the wastes from ash fill area 1. These costs are amounts that would not have been expended under the Company's preferred closure plan embodied in the January 2014 AMEC Plan, and are therefore identifiable and quantifiable. Based on my conclusion that the Company's imprudent management of the surface impoundments at Dan River, resulting in the ash release into the Dan River in February, 2014, is the direct cause of the Company's inability to implement the preferred closure plan, I likewise would disallow all costs incurred by the Company for closure activities at the Dan River Plant in excess of amounts otherwise required to implement the January 2014 AMEC Plan. Unfortunately, however, the record does not include any cost estimates for the January 2014 AMEC Plan, and it is most likely that the occurrence of the ash spill on February 2, 2014, pre-empted any further development of such cost estimates. In the event the matter is brought before the Commission in the future and in a proper procedural context, the question whether these excess costs can be quantified will warrant further inquiry.[34]

C. The Company's Handling of Cost Recovery for Anticipated Waste Ash Disposal Costs

I do not disagree with the majority's decision to permit the Company to account for its ongoing and future ash basin closure costs in accord with SFAS 143, at least as it pertains to the closure of ash storage and disposal facilities that are subject to one or more of the federal CCR Rule, CAMA, or applicable final judicial and/or administrative orders.[35] My concern in the present discussion centers on the manner in which the

[34] The Company's Riverbend plant was, like the Dan River Plant, also pre-emptively designated by the General Assembly in CAMA as a "high-risk" site. The Company's preferred pre-CAMA closure strategy for Riverbend had been to cap the existing impoundments in place, but this option was foreclosed by CAMA. Some of the Company's internal documents, however, suggest an awareness by the Company that the cap-in-place concept might not have been ultimately viable at Riverbend because the plant was located in an area designated as a "critical watershed" for public drinking water supplies. See., e.g., Kerin Direct AGO Cross Ex. 2, p. 253. For this reason, among others, I do not believe the record would support any finding that the Company's imprudent actions or omissions are responsible for the closure strategy ultimately adopted and implemented for the Riverbend plant.

[35] The central focus of all parties in this case has been on the surface impoundments used to store coal ash wastes. These impoundments are subject to both the CCR Rule and CAMA, and have been the subject of several judicial and administrative decrees. Over time, the Company has operated other ash storage and disposal facilities at some of its plants that are not regulated under CAMA, the CCR Rule, or any other regulatory regime. The record does not permit a determination as to whether or not the costs of closure of all of these dry storage areas qualify for accounting treatment under SFAS 143 or whether, instead, they should continue to be recorded and reported under the principles set out in SFAS 19. In its discussion of ARO accounting the majority order refers to and discusses the December 21, 2015 letter from Brian Savoy (Savoy Letter), notifying the Commission that the Company would implement SFAS 143 accounting treatment for its waste ash basin closure costs. One point in the Savoy Letter bears upon a subsidiary issue but requires comment here. The letter states: "Coal Ash Basin costs that relate to activities outside the scope of the aforementioned legally required activities (e.g., Federal CCR rules and the NC CAMA legislation) are being expensed immediately as Operations and Maintenance (O&M) expense." In the course of the hearings on the Company's current application, the Company was asked whether the closure costs associated with non-CAMA and non-CCR Rule regulated sites, specifically the inactive ash basin and the borrow area at the Lee Plant, were included in the Company's reported ARO liabilities.

Company accounted for and treated for ratemaking purposes the anticipated costs for closure of the waste ash storage and disposal facilities before it established ARO accounting for those costs. This is a topic not addressed by the majority in its opinion, and I believe this omission is error.

Before the promulgation of SFAS 143, and afterward for all cases that do not fall within the jurisdictional scope of SFAS 143, costs expected to be incurred upon the retirement and decommissioning of a long-lived asset were typically estimated as part of the terminal net salvage value of the asset, which was a component of depreciation. For regulated entities these anticipated costs of removal were included in allowed depreciation expense and were collected in rates. Costs of removal include such items as dismantlement and demolition of structures, sale of salvaged equipment and materials, site restoration, and any necessary environmental remediation costs. When costs of removal were expected to exceed the salvage value of reusable and useful facilities, equipment and materials, terminal net salvage value would be a negative number, and this would serve to increase the annual depreciation expense associated with the long-lived asset. See, e.g., the discussion in Doss Ex. 3, p. IV-2 (Ex. Vol. 12, p. 787). Typically, though not in all cases, accumulated depreciation was recorded for financial statement reporting purposes as a "contra asset," that is, as a deduction from the carrying value of the associated asset on the balance sheet. Usually, though again not always, costs of removal were not adjusted for future inflation or discounted to present value, although they would be subject to adjustment according to periodic updates to depreciation studies and resulting changes to depreciation rates.[36]

The Company's position in this case is that it first became subject to the financial statement reporting requirements of SFAS 143 upon the enactment of CAMA and the adoption of the CCR Rule. While I believe an argument can be made from the evidence presented in this case that earlier application of SFAS 143 might have been required in the case of at least some of the Company's waste ash units, for purposes of the present discussion, I have accepted the Company's position concerning the triggering events for conversion from traditional depreciation accounting for costs of removal to accounting under SFAS 143.[37]

Because it is the Company's position that the September, 2014 consent agreement triggers ARO accounting for these two waste units, the Company reported in its April 6, 2018 filing showing that the costs associated with these two facilities were included in reported ARO liabilities. However, that letter appeared to speak more generally also, saying that estimates and actual expenditures "... are not tracked on a basin-by-basin basis, but on a site-by-site basis." This statement needs to be reconciled with the portion of the Savoy Letter quoted above. I believe the Commission should direct the Company to identify all such unregulated waste units for which closure tasks are being performed and for which costs are being incurred and confirm that no portion of those costs are included in the ARO liabilities reported in Kerin Direct Ex. 11 in this case or in the allowed amounts that are being deferred and amortized by the Majority Order in this case.

[36] This summary is largely drawn from the more detailed explanation of the concepts contained in SFAS 143 and SFAS 19.

[37] In brief summary, the argument would be that final closure of ash storage and disposal facilities upon retirement was a known requirement under the regulatory regime established pursuant to the Clean

It is likewise the Company's position in this case that before its adoption of ARO accounting for the waste impoundment closure costs, it had not included any estimated costs for such closures in its estimation of terminal net salvage values for the generating plants of the impoundments served, and did not, therefore, include any such amounts in its depreciation rates requested and approved under G.S. 62-133(b)(3). Thus, the Company did not collect any such amounts from ratepayers in prior rates. Company witnesses Spanos and Kopp, who prepared and explained the depreciation study offered by the Company in this case, testified that the depreciation study and the requested rates based on that study included no costs of removal for the waste ash impoundments and that, moreover, the depreciation studies and requested rates in the Company's prior rate cases in 2007, Docket No. E-7, Sub 828; in 2009, Docket No. E-7, Sub 909; in 2011, Docket No. E-7, Sub 989; and in 2013, Docket No. E-7, Sub 1026, likewise had included no amounts for costs of removal of the ash impoundments. *They testified that this was so because they had not been asked to include any such elements of cost in their depreciation studies and had been given no information on the subject.* See Tr. Vol. 9, pp. 124-125.[38] Based on this evidence, I find it legitimate to ask whether it was reasonable and prudent for the Company to have omitted all costs of removal for the ash impoundments from its requested depreciation rates in any of its rate cases prior to this one and, if not, what consequences should follow from that omission.

Other evidence in the case, notably Fountain AGO Cross Ex. 6 (Ex. Vol. 10, pp. 609-694) establishes that the Company *did* estimate negative terminal net salvage values for its coal-fired generating plants, *did* include those negative values in the calculation of its requested depreciation rates, and *did* include those negative values in rates collected from customers. Apparently, however, those negative values addressed only plant decommissioning costs other than costs of closure of the waste ash impoundments at the coal-fired plants. Fountain AGO Cross Ex. 6 is a slide presentation titled, "Ash Basin Closure Update," dated January 13, 2014, only days before the ash release at the Dan River Plant, made to the Company's Senior Management Committee on the status of the Company's activities and plans, and those of its regulated affiliates, relative to management of coal ash wastes. Among the topics covered in the presentation

Water Act, and that the costs of closure were reasonably subject to estimate, and in some cases were in fact estimated by the Company, well before the enactment of CAMA or the CCR Rule. In any event, I do not base my conclusion here on any finding that the Company should have requested approval of ARO accounting any sooner than it did.

[38] Under the transition provisions in SFAS 143, when ARO accounting treatment is established for an existing long-lived asset for which depreciation has been and is being taken, the accumulated depreciation is incorporated in a cumulative adjustment to the financial statement, essentially being taken as a credit or reduction of the amount of the recognized and recorded ARO liability. If, as is the testimony in this case, no costs of removal had been collected in depreciation expense, then no credit would have been booked to the ARO liability recorded when the Company adopted SFAS 143 treatment for its ash impoundment closure costs.

was the recovery of costs associated with closure of the ash basins at each of the Company's coal-fired generating plants.[39]

One presentation slide discloses that the Company had collected through depreciation expense costs of decommissioning for its coal-fired plants of some $224 million and that it was possible that some or all of this amount could be tapped to offset a portion of expected costs for closure of the ash basins.[40] At the time of the presentation, the Company's costs to close the ash impoundments, assuming, as in fact turned out to be the case, that the wastes would retain their non-hazardous classification, was estimated to be approximately $610 million. Again, though, the accumulated cost of removal amount for the coal-fired plants, according to the Company's testimony presented in this case, did not include any amounts for the ash impoundments themselves, so any use of the accumulated amount would have potentially left the Company facing insufficient cost recovery for its other plant decommissioning costs.[41]

A final bit of confirmation that the Company's depreciation expense included in its rates did not include any amounts for costs of closure of its waste ash impoundments comes from the application in Docket No. E-7, Sub 1110, which is the Company's application for a regulatory accounting order allowing it to use ARO accounting for expected ash basin closure costs. In its filing, a joint filing with its affiliate DEP,[42] the Company commented that DEP had been collecting as part of costs of removal a specifically earmarked sum for coal ash impoundment closure costs since its last general rate case in 2013. See, e.g., Docket No. E-2, Sub 1023. Nothing similar was disclosed or reported with respect to the Company's own posture on the subject. See also, AGO Late-Filed Ex. 1, Tab L, p. 25, stating: "DEP in the Carolinas, very recently started including recovery for specific ash pond closure costs in their COR rates. DEC still does not have specific related ash pond closure costs in the COR rates."

The Company very clearly knew that costs of removal upon plant decommissioning were a proper component of terminal net salvage values and thus a proper and

[39] I note that this presentation, and most of the other documents I will review, were all dated prior to the enactment of CAMA, prior to the adoption of the CCR Rule, and prior to the Company's plea agreement in its federal criminal case.

[40] This amount is referred to as a "reserve," but it did not represent a segregated fund in the same sense as, say, the nuclear decommissioning trust fund. It instead represented amounts included in rates pursuant to G.S. 62-133(b)(3), but, as noted in the presentation, the Company would nonetheless have to identify a source of cash for the expenditures to which this "reserve" had been accumulated. In addition to the amount separately identified as accumulated costs of removal for the steam plants, the document also disclosed the total accumulated costs of removal for all other asset groups other than nuclear plant, including non-coal generating units, transmission system assets, and distribution system assets.

[41] The same information contained in Fountain AGO Cross Ex. 6 is also provided in a post-hearing exhibit filed by the Attorney General in response to questioning by Commissioners concerning the possible existence of other documents addressing the subject matter of Fountain AGO Cross Ex. 6 See AGO Late-Filed Ex. 1, Tab L.

[42] The Company's filing is assigned Docket No. E-7, Sub 1100. The companion filing by DEP was assigned Docket No. E-2, Sub 1103.

recoverable element of depreciation expense. Should it have included costs of closure for the waste impoundments in its broader estimate of decommissioning costs and, if so, when should it have done so? Answering this question requires, I believe, examination of two things: the development of industry standards and best practices concerning the decommissioning of coal-fired generating plants and their associated waste ash storage and disposal units, and the Company's own internal policies and planning for the retirement of its fleet of coal-fired plants, including the associated ash impoundments, in the time period before the enactment of CAMA in 2014 and adoption of the final CCR Rule in 2015.

The earliest evidence in the record bearing upon these questions is contained in the Electric Power Research Institute's (EPRI's) Coal Ash Disposal Manual, Second Edition, published in October, 1981. Kerin Sierra Club Cross Ex. 4 (Ex. Vol. 16, Part 1, pp. 281-356; complete report filed by Sierra Club on March 15, 2018). The manual is a comprehensive treatment of the then state-of-the-art theory relative to a number of topics, including procedures and practices for closure of waste ash storage and disposal facilities. In its scope section, the manual explains:

> The purpose of Section 8, Site Reclamation, is to present information on site reclamation procedures for ash disposal areas. Because of increased environmental awareness, increased concern for site aesthetics and resulting public opinion, and more stringent environmental regulations, efforts to reclaim and revegetate disposal sites have recently accelerated; however, there is considerable confusion regarding which methods are appropriate .... To assist utility personnel in dealing with site retirement procedures in their area, this section gives specific guidance to effective and economical site retirement and revegetation procedures, as well as sources of additional information and assistance.

Id. at 287.

Section 8 of the manual contains an extensive technical and environmental analysis of methods of retirement and closure for ash storage and disposal facilities, including landfills and surface impoundments. The preliminary scope statement for Section 8 reads:

> The advent of recent federal and state laws involving clean water and waste disposal standards has created a need to closely manage the progression and final closure of ash disposal sites.

Complete EPRI Report filed by Sierra Club, p. 8-1 (March 25, 2018).

This EPRI Report is of particular interest because two of the field sites studied and reviewed in the manual were the Company's Allen and Marshall Steam Stations. In Section 6, the manual describes activities being undertaken by the Company at the inactive ash basin at its Allen Plant to experiment with different types of soil cover and different types of revegetation following decommissioning of the basin. It was clear that as early as 1981, closure and reclamation of retired ash storage and disposal facilities was a topic for which utilities were planning and were expected to be planning, and that the Company itself was already experimenting with closure techniques at its Allen Plant.

In August, 1982, EPRI published a second report titled Manual for Upgrading Existing Disposal Facilities, which addressed practices, standards, and options for addressing deficiencies identified in the course of operating existing ash storage and disposal facilities. Kerin Sierra Club Cross Ex. 2 (Ex. Vol. 16, Part 1, pp. 224-262). The manual notes that its purpose was "... to provide the industry with detailed information about design features, equipment selection, and specific procedures for evaluating current disposal system suitability and selecting optimal retrofit systems for existing disposal facilities." Id. at 226. The EPRI Manual was based on survey research and field site research. Summarizing the deficiencies most often noted in field inspections, the report identified four of particular note, one of which was "closure/post closure plans were inadequate or nonexistent." The manual included not only procedures and recommendations for upgrading facilities and correcting deficiencies but also a methodology for calculating the costs of various upgrades.[43]

By not later than the 2000s, the matter of retirement and decommissioning of coal-fired generating plants constructed in an earlier era had become a topic of greater focus. In November, 2004, EPRI published another manual, this one titled Decommissioning Handbook for Coal-Fired Power Plants. Ex. Vol. 10, pp. 695-782. The manual alerted its users that:

[43] This manual is of particular interest in light of witness Kerin's testimony that in the absence of a regulatory directive to do so, it would not have been reasonable for the Company to modify existing ash impoundments that were still receiving wastes and operating under NPDES permits. Tr. Vol. 14, p. 110. I find that the EPRI Manual confirms that the "minimum required by law" standard of operation advanced in some of the Company's testimony through its witnesses Kerin, Wright and Wells is simply wrong. In its preliminary pages, the EPRI Manual notes:

> Potential deficiencies in utility waste disposal practices may be defined by two sets of standards:
>
> -The disposal practice does not comply with specific federal and/or state regulatory requirements.
>
> -The site has the potential to contaminate the environment.
>
> This seemingly redundant statement is important to any assessment of disposal site deficiencies. Identification and correction of regulatory deficiencies do not necessarily preclude the possibility of past or future environmental degradation by the site. Conversely, known degradation cannot be corrected by simply conforming to the regulations.

Ex. Vol. 16, Part 1, pp. 240-241.

The 1982 EPRI manual is not the only document in the record that communicates this same point. A minimalist view of the requirements of "prudence" simply does not comport with actual industry practices and standards or, as we shall see, with the Company's own view, at least as set out in documents authored prior to this case.

> [t]here are serious issues in plant site decommissioning, most of them environmental. The disposal of many years of waste products – ash, water, oils, chemicals – and the removal of asbestos, PCBs, lead products, etc., requires both an understanding of the extent of the contaminations as well as the best methods of removing and disposing of the substances.

Id. at 704. Discussing the various tasks and costs that could be expected as part of the retirement of a plant, the manual later observed that "[c]losure of surface impoundments and landfills probably will be the most expensive tasks undertaken during a decommissioning project," (Id. At 722), and followed this with the explanation that

> [c]losure of most surface impoundments will require drainage, placement of an impermeable cap, and topping with soil and a vegetative cover. … The caps for the impoundments will require continued maintenance to maintain the site contours, vegetative cover and drainage. Some impoundments will require the installation and monitoring of groundwater wells. The waste in other surface impoundments may be excavated for disposal offsite, and the impoundment backfilled with clean material.

Id. at 724. The manual provided three case studies of plant decommissioning, along with a discussion of the estimated or actual costs incurred. One of the examples was Georgia Power Company's Arkwright Plant, which had ceased operations in 2002, and where final site cleanup was expected to be completed in 2006. The study reported that the costs for closure of waste ash surface impoundments at the Arkwright plant were estimated to be $10,700,000, or some 56.3% of total decommissioning costs net of salvage recovery. Id. at 753. For the Tennessee Valley Authority's Watts Barr plant, finally retired in 2000, the costs for closure and remediation of both dry ash units and surface impoundments were estimated to be $9 million, out of a total cost range estimated to be between $17 million to $25 million in 2000 dollars. Id. at. 754. From the Decommissioning Manual it was clear that the costs of closure of waste ash disposal facilities would not be a trivial or *de minimis* item.

The Company was not unaware or unmindful of the industry practices and learnings evidenced in reports and studies such as these three EPRI manuals and had incorporated them into its own internal policies.[44] Based on the entire record, I conclude,

[44] For brevity, I have selected these three EPRI documents as representative of industry knowledge and practices. The record contains numerous other documents that are fully consistent with and support the conclusions I draw here, including Junis Public Staff Exhibit 4 (Environmental Control Implications of Generating Electric Power from Coal, Argonne National Laboratory, December, 1976); Kerin Sierra Club Cross Ex. 3 (Los Alamos Scientific Laboratory, The Disposal and Reclamation of Southwestern Coal and Uranium Wastes, May, 1979); Junis Public Staff Ex. 9 (Proceedings of the American Society of Civil Engineers, Water Quality Issues at Fossil Fuel Plants, October, 1985, including a case study of releases of selenium from the Company's Belews Creek Steam Station); Kerin Sierra Club Cross Ex. 5 (EPA Report to Congress, Wastes from the Combustion of Coal by Electric Utility Power Plants, 1988); Wells Public Staff Cross Ex. 6 (Arthur D. Little, Inc., Full-Scale Field Evaluation of Waste Disposal from Coal-Fired Electric Generating Plants, June, 1985, including in particular a field evaluation and analysis of coal waste handling practices and environmental conditions at the Company's Allen Steam Station; and Ex. Vol. 12, pp. 220-290; and Wright, Public Staff Cross Ex. 5 (EPA Office of Solid Waste, Coal Combustion Waste Damage

on a conservative basis, that by not later than the time of its 2009 general rate case, and most likely sooner, the Company had formed an understanding that: (1) permanent closure of its waste ash storage and disposal facilities would be required when the associated coal-fired generating units were retired, if not sooner; (2) closure of these waste units would constitute a substantial portion of the total costs of decommissioning the plants; (3) planning and investigation of options and development of timetables should begin well in advance of the time of actual plant retirement; and (4) provisions for cost recovery of such closure costs should be developed. These points are extensively developed and documented in a series of internal Company documents, including the following:

- Ten-Year Coal Combustion Products Plan, 2003 (Kerin AGO Direct Cross Ex. 1)
- Ten-Year Coal Combustion Products Plan, 2008 (Kerin Direct Public Staff Cross Ex. 2)
- Duke Energy Environmental Management Program for Coal Combustion Products, dated May 29, 2007, (Kerin AGO Direct Cross Ex. 3)
- Environmental Management Program for Coal Combustion By-Products, dated June 27, 2007 (Kerin AGO Direct Cross Ex. 5)
- 2012 Plant Retirement Comprehensive Program Plan (Doss AGO Cross Ex. 1)
- Guidance on Developing Closure Plans for Ash Basins, September 27, 2012 (AGO Late-Filed Ex. 1, Tab A)
- Ash Basin Closure Strategy, (AGO Late-Filed Ex. 1, Tab E)(undated, but from internal evidence in the document likely dated in 2013)
- Demolition and Plant Retirement Presentation, dated February 16, 2013 (AGO Late-filed Exhibit 1, Tab F)
- Environmental Talking Points for Presentation to Board of Directors, August 27, 2013 (AGO Late-Filed Ex. 1, Tab I)
- Plant Demolition and Retirement Presentation for the Executive Governance Committee, October 14, 2013 (AGO Late-Filed Ex. 1, Tab J)
- Ash Basin Closure Strategy Presentation to the Senior Management Committee, November 25, 2013 (AGO Late-Filed Ex. 1, Tab L)[45]

Case Assessments, July, 2007). These documents all demonstrate that industry knowledge with respect to the environmental risks and implications of coal waste handling practices was more advanced at an earlier date than contended for by some of the Company's witnesses and that recommended best practices were, since at least the early 1980s, more sensitive to environmental concerns than represented by a bare minimum standard of regulatory compliance.

[45] Consideration of these critical internal policy documents is, by and large, missing from the discussion in the majority order. All of these documents pre-date the enactment of CAMA or the CCR rule. Even under the law as it existed during that time, the Company knew that regulatory closure would be required when the ash basins were retired. Representative is the following statement from an undated document likely authored in 2012 or 2013:

> Currently, federal regulatory programs do not specifically address the decommissioning and closure of ash basins; however, state regulations provide some options for closure framework. The

The intensified focus on closure of coal ash waste facilities in the 2000s was driven in large part by the aging of the Company's existing fleet of generation units and by the economics that increasingly favored conversion from coal to natural gas as a fuel. From this internal evidence it is clear that the Company was on notice throughout the decade of the 2000s and into the present decade, that the costs of removal of its waste ash storage and disposal facilities would affect, most likely very significantly, terminal net salvage values of its plants and thereby the amount of allowance it should seek to recover from ratepayers as depreciation expense. However, according to the testimony in this case, at no time during that period, including in its general rate cases in 2009, 2011, and 2013, did the Company include any provision for such costs of removal in its depreciation studies presented to the Commission. At least some portion of the costs the Company now seeks to recover in rates prospectively thus represents amounts the Company could have, and in my judgment prudently should have, recovered through depreciation expense in its existing and previously approved rates.

My view on this point is I believe in line with the Commission's decision in Order Granting Partial Rate Increase, Docket No. W-218, Sub 319 (November 3, 2011) (Aqua Order). In that proceeding, Aqua and the Public Staff disagreed as to the propriety of including in depreciation expense, and thus in rates, amounts for terminal net salvage value that would also incorporate costs of removal. The Company's witnesses pointed out that including these amounts in current depreciation expense would properly assign a portion of expected future expenses to those customers who were currently receiving the benefit of the utility plant while it was still in service. The Public Staff contended that such a practice would improperly require present customers to pay for future costs that might or might not actually be incurred, or might be different in amount at the time actually incurred. As to this difference of opinion, the Commission noted the applicant's testimony in the following summary:

> Witness Spanos[46] advocated utilizing the net salvage percentage for depreciation accrual rates consistently with the new practice[47] of recording the cost of removal as the most appropriate methodology. Therefore, according to witness Spanos, the cost of removal for each project will be charged to accumulated depreciation at the same time the Company accrues for the net salvage value in rates. Witness Spanos asserted that this consistent treatment properly assigns costs to those ratepayers receiving benefit for the asset while in service; this applies to all accounts.

company is working closely with NCDENR to define a closure process that provides a framework for certainty in the absence of specific federal regulatory requirements.

AGO Late-Filed Ex. 1, Tab E (Filed on April 18, 2018.)

[46] This is the same witness Spanos who testified for the Company in the present case.

[47] Elsewhere in the Aqua Order, it is made clear that "new practice" means "new for this applicant," not new for the accounting profession. Prior to Aqua's 2011 rate case, Aqua North Carolina had not been computing net salvage values as part of depreciation expense.

Aqua Order at 70. Aqua Witness Spanos further explained that the entire cost of the asset, including costs of removal, should be recovered over the useful life of the asset and not recovered from customers after the asset's useful life had ended. Id.

In its order the Commission disagreed with the Public Staff's position and instead sided with the Company and its depreciation expert, witness Spanos, finding that:

> …utilizing the net salvage value percentage for depreciation accrual rates consistently with the new practice of recording the cost of removal is the most appropriate methodology. The Commission understands that using this methodology, the cost of removal for each project will be charged to accumulated depreciation at the same time the Company accrues for the net salvage in rates. *This treatment properly assigns costs to those ratepayers receiving benefit for the asset while in service and properly applies to all accounts.*

Id. at 72 (emphasis added).

In the present case, the Company's failure to seek recovery of waste ash storage and disposal costs as part of current depreciation expense in prior rates means that some portion of the properly allocable full cost of providing service to an earlier generation of customers will now be shifted to, and recovered from, future ratepayers. This is not in keeping with the sound policy and principles endorsed in the Aqua Order, nor do I believe it is consistent with the principles stated and endorsed by the Supreme Court in State ex rel. Utilities Commission v. Edmisten (Edmisten III), 291 N.C. 451, 232 S.E.2d 184 (1977). The Company is now seeking to recover from present and future ratepayers a cost that is attributable to service provided to ratepayers in prior periods. That cost is depreciation expense, more precisely that portion of depreciation expense representing the costs of removal upon final facility retirement that should be allocated among ratepayers over the entire useful life of the asset and not fall entirely upon those ratepayers at the time retirement occurs and funds are expended for decommissioning.

Some intervenors in this case have suggested that for any waste ash storage or disposal facilities associated with a generating plant, these costs of removal should have been collected through depreciation since the time the waste ash facility was first placed in service. On the present record, however, it is not possible to reconstruct this scenario today, and I have concluded that it is more reasonable to use as a beginning point the time the Company first knew or reasonably should have known, based on information available to it at the time, that it would incur substantial costs to close the waste facilities at the time of plant retirement and decommissioning. Based on the evidence recited earlier, this point in time was manifestly earlier than the date of enactment of CAMA or the adoption of the CCR Rule. I also conclude that it was at a point in time that predates the Company's general rate cases in 2009, 2011, and 2013, in none of which did it seek any provision for cost recovery of then-anticipated cost of removal of the waste ash storage and disposal facilities.[48]

The difficulty, of course, lies in determining how much cost has been improperly and imprudently shifted from past customers for service previously received, to present and future customers for service yet to be provided them. One device would be to look to the actions of the Company's affiliate, DEP, which requested and received approval in its 2013 general rate case to collect $10 million per year from customers for estimated costs of removal of its waste ash facilities. I do not find this option acceptable, however, since it ignores pertinent differences in the two companies' history of management of coal ash wastes and, more importantly, in the physical, environmental, and economic circumstances of their fleet of coal-fired plants and their associated waste ash facilities.

From the available evidence in the record I find that the cost estimates contained in two exhibits, Doss AGO Cross Ex. 1 (Ex. Vol. 12, pp. 818-839) titled "Plant Retirement Comprehensive Program Plan," and Atty. Gen. Late-Filed Exhibit 1, Tab J, titled "Plant Demolition and Retirement Presentation for the Executive Governance Committee," dated October 14, 2013, are the most appropriate to use for present purposes. The Plant Retirement Comprehensive Plan, dated October 31, 2012, sets forth the Company's then best estimates of plant decommissioning costs and, separately from general costs, costs for closure of waste ash storage and disposal facilities at the retired plants.[49] For the four coal-fired plants already retired or for which a near-term retirement date had been established - Buck, Dan River, Riverbend, and W.S. Lee – the estimated costs for closures of ash storage and disposal facilities totaled $115,538, 470. Interestingly, the estimate for other decommissioning tasks at these four retired plants totaled $32,323,875, confirming the statement in the 2004 EPRI plant decommissioning handbook that the costs of closing waste storage and disposal facilities would likely be the largest portion of plant decommissioning expense. The budgeted figures for closure of the waste ash facilities at the Buck, Dan River and Riverbend plants contained in the October, 2013, Plant Demolition and Retirement Presentation is $111,361,000. This total is less than the aggregate total in the 2012 comprehensive plant retirement plan, but it does not include any estimated costs for the waste facilities at the W.S. Lee Steam Station. Comparing

[48] There is nothing in this record to show that in setting the Company's prior rates the Commission was presented with any evidence concerning costs of removal for the waste ash impoundments apart from the general estimation of terminal net salvage values for the coal-fired generating plants contained in depreciation studies prepared by the Company's experts and relied upon by the Commission. For example, in Docket No. E-7 sub 1126, the Company's last general rate case before the instant proceeding, the depreciation study for each generating plant contained a negative allowance for terminal net salvage value for "Structures and Improvements," (Docket No. E-7, Sub 1126, Wiles Direct Ex. 3, p. 47), without further breakdown of the elements of cost entering into the calculation. Based on the evidence before it, the Commission had no ability to assess whether the Company had correctly or incorrectly identified and incorporated all the tasks that would be required upon plant retirement or whether it had identified and incorporated all the estimated costs of those necessary tasks. It was incumbent upon the Company to petition for and present evidence of the amounts needed to cover its known and expected expenses, including depreciation expense. E.g., New Jersey Power & Light Co. v. State Dep't. of Public Utilities, 15 N.J. 82, 92; 104 A.2d 1, 18 (1954)(cited with approval in Edmisten III).

[49] This plan is not a mere proposal; it carries all necessary approval signatures.

"apples to apples," the total estimate in the 2012 plan for the Buck, Dan River and Riverbend plants only was $93,272,969, meaning that the budget for closure activities at these three plants increased by $18,089,031 between 2012 and 2013. Both the 2012 and 2013 documents estimate expenditures over the same time period – 2013 through 2018. If the 2012 estimated closure budget for the W.S. Lee plant is added to the revised 2013 budget number for the Buck, Dan River and Riverbend plants, then the resulting total would be $133,626,501. As a point of comparison, this total is dramatically less than the $1,267,692,514, including in that total amounts for expected inflation, the Company now estimates it will spend over the next fifty years for closure of the waste ash units at these four plants. See Kerin Direct Ex. 11, p. 1.

Based on the available evidence, I find that the Company should have sought to collect in present and previously approved rates as costs of removal for the waste ash facilities at its four retired coal plants an amount not less than $133,626,501, and that its failure to do so was unreasonable and imprudent based on its knowledge at the time. Considering our obligation to be fair and reasonable both to ratepayers and to the Company and the requirement that we judge the Company based on information known to or reasonably available to it at the time of its conduct under examination, I conclude that the Company's present request in this rate case for recovery of amounts expended during 2015 through 2017 should be reduced by the amount of $133,626,501. Given the Company's long-standing and extensive knowledge of the types and magnitudes of costs it would have to incur, the certainty even before CAMA and the CCR Rule that it would be incurring them upon plant retirement, and its failure to seek to spread these costs equitably to all ratepayers who received benefit from the electricity service that caused such costs to be incurred, I believe this is a just and reasonable result. It avoids transferring to present and future ratepayers costs that should have been collected from ratepayers in prior periods.

Strictly applying the foregoing principles and analysis, it is unquestionably true that some amounts should also have been requested in depreciation rates prior to the present case for estimated costs of closure of waste ash facilities at the Company's operating plants, Allen, Belews Creek, Cliffside, and Marshall. However, in this record there is no evidence upon which a reasonable judgment could be made as to the additional amount attributable to these plants.[50] I note that the Company's cost recovery request for coal ash expenditures in 2015, 2016, and 2017 at these four plants largely consists of items that would be classified as inspection, maintenance, and repair activities at the existing waste impoundments, together with site assessment, planning and closure plan preparation activities. Actual costs for dewatering, consolidating, excavating, capping, and similar closure tasks remain for the future. There will be opportunity in the Company's

[50] Some closure estimates are provided in AGO Late-Filed Ex. 1, Tab L, p. 34 based on three different closure scenarios. These estimates are in a document dated November 25, 2013, after the filing of the Company's most recent general rate case application preceding the present one. I am unable to extract from this evidence, however, any reasonable estimate of amounts that the Company should have attempted to collect as costs of removal in prior rate cases. I consider the evidence more reliable in the case of the four retired plants because their retirement had been planned and information concerning closure of the ash impoundments had been studied and assembled over a period of years prior to the 2012 and 2013 estimates upon which I rely.

next general rate case to consider further the issue discussed here as it may relate to the Company's remaining coal-fired plants.

II. Rate of Return on Unamortized Coal Ash Waste Costs and "Mismanagement Penalty"

In this part I address my disagreement with the majority's decision to permit the Company to earn an investment return, equal to the weighted average cost of capital, on the deferred unamortized balance of its expenditures on closure of coal ash impoundments during the years 2015 through 2017 and its decision to impose a penalty for mismanagement of the ash basins in the amount of $70 million. Though these appear to be separate decisions, they are necessarily linked. The Commission first proposes to allow the Company to earn a return that I believe is, as to some of the costs involved, contrary to law and as to other portions of the costs, an abandonment of sound policy and practice and, on the record taken as a whole, an improper exercise of discretion. Having made this allowance, the Commission then reduces the total amount of the permitted return by $70 million and terms that reduction a "penalty" for mismanagement. Because there is no penalty if there is no allowed return on the unamortized balance of the waste ash costs, I focus my dissent on the first of these two decisions.

By way of opening I refer to and adopt in this case my rationale for denying a return on the unamortized balance of ash impoundment closure costs contained in my dissent in the DEP Rate Case Order. From the record assembled in this case, I have identified additional grounds to support the conclusion reached in my dissent in the prior case. On some points these additional grounds are based on matters and facts that may also have been pertinent to the decision in Docket No. E-2 sub 1142 but as to which the record was either silent or insufficiently complete to enable a judgment to be formed in that case.

A. <u>SFAS 143, Ratemaking, and Property "Used and Useful"</u>

The first issue I address is the irrelevance of SFAS 143 (now codified as ASC 410) to the issue at hand. The majority order has, I believe, conflated concepts of financial statement presentation with the classification of costs for ratemaking purposes. To avoid repetition I will not reprise the basic operation of SFAS 143 (now, which is reviewed at length in the Majority Order. Majority Order at 286-292. My focus here is on the majority's use of SFAS 143 to arrive at the conclusion that amounts expended by the Company for such tasks as dewatering surface impoundments, preparing ash for beneficiation or for disposal, excavating ash from its current storage location, transporting that ash to a new permanent disposal location onsite or offsite, and then monitoring and maintaining that permanent disposal site over an extended period of years have become "…property used and useful, or to be used and useful within a reasonable time after the test period, in providing the service to be rendered to the public within the State…," making those expenditures eligible to earn a rate of return pursuant to G.S. 62-133(b)(4) and (b)(5). I do not believe SFAS 143 leads to such a result. More importantly, if it does produce such a result, that result is in conflict with the statutory language and structure of G.S. 62-133 and cannot be accepted.

Expenditures such as those catalogued in the preceding paragraph are not in themselves "property," although they are associated with "property," that being the waste ash impoundments. For purposes of SFAS 143 accounting treatment the waste ash impoundments are "long-lived tangible assets." For purposes of G.S. 62-133(b)(1) they either are now or formerly were "property used and useful in providing service."[51] The fact that they are associated with and related to "used and useful property" does not itself make them eligible for allowance of a return computed under G.S. 62-133(b)(4). If they are properly classified as "operating expenses" for purposes of G.S. 62-133(b)(3), then they are not eligible for a return. See, e.g., State ex rel. Utilities Commission v. Public Staff N.C. Utilities Commission, 333 N.C. 195, 424 S.E.2d 133 (1993) (reasonable operating expenses must have a nexus to property used and useful in providing service, but that nexus does not render operating expenses allowable under G.S. 62-133(b)(3) eligible for a return).

How, then, do expenses that would be considered "operating expenses" under G.S. 62-133(b)(3) become transformed by SFAS 143 into "property used and useful in providing service?" I believe the core of the majority's argument is contained in the following sentence: "Recognition of the [ARO] liability carries with it recognition of a corresponding asset – the capitalized cost of settling the liability, which under both GAAP and FERC rules is considered part of the property, plant and equipment for the assets that must be retired." Majority Order at 287. This statement requires careful attention, because it leads directly to what I believe is an error of law.

Under SFAS 143 when an asset retirement obligation is recognized and is recorded on the liability side of the balance sheet, of necessity there must be some corresponding and offsetting entry made on the asset side of the balance sheet. This is so because SFAS 143 is not structured such that the recognition of an asset retirement obligation, or "ARO," is meant to produce an immediate charge to retained earnings or to the equity account. The "asset side" adjustment is made by increasing the carrying cost of the long-lived asset to which the ARO relates by an amount equal to the amount of the recorded ARO liability. This increase in the balance sheet carrying value of the asset, called the "asset retirement cost" or "ARC," does not correspond to any actual increase in the value of the asset to whose book entry the ARC is added. Nothing at all has changed about the character, the qualities, the marketability, or the usefulness of the asset "…in providing the service to be rendered to the public." Likewise, nothing has changed about the "reasonable original cost of the public utility's property" embodied in that asset. The recording of the ARO liability and the capitalization of the ARC result from the change made by SFAS 143 in the timing of recognition of future cash outlays that are anticipated to be made at the time a long-lived asset is retired. The expenditures are not current outlays, but their recognition has been accelerated for financial statement presentation, and accelerated recognition must be offset by an entry on the asset side of the balance sheet.

[51] The difference between "now" and "formerly" is quite important, and is the subject of the discussion in Part II.B., as set forth hereafter. It is not a difference that is material, however, for purposes of the present argument in this section.

From this balance sheet entry, however, the majority order concludes that because the costs associated with the closure of waste ash impoundments are now capitalized on the balance sheet, the expenditures made for those closure activities "…whether they be denominated capital costs, O&M costs, general administration costs are nevertheless capitalized in connection with the establishment of the ARO…." Majority Order at 288. Restating the same point later, the majority says: " ...when properly accounted for in an ARO, the specific classification of costs is not determinative, because under GAAP and FERC guidance ARO costs are capitalized." Id. at 289. The analysis in the majority order boils down to this: because SFAS 143 requires that the carrying cost of the tangible asset with which an asset retirement obligation is associated must be increased for balance sheet purposes by the amount of the asset retirement obligation when that liability is recognized and recorded, the increase in the balance sheet carrying value of the long-lived tangible asset then becomes eligible for the recovery of a return under G.S. 62-133(b)(4) and (b)(5). This is error.[52]

There are multiple difficulties with this analysis as a matter of basic statutory construction of G.S. 62-133. It is, after all, that statute that controls the ratemaking treatment of costs – of all kinds and classification -- and the determination of which elements of cost are eligible to earn a return. Most immediately, G.S. 62-133(b)(1) requires that the Commission use as its basis or starting point, "the reasonable *original* cost of the public utility's property…." (emphasis added.) The amount of a balance sheet adjustment made to the carrying value of an asset when an asset retirement obligation is recognized in accord with SFAS 143 is manifestly not part of the "original cost" of that asset. Allowing the "original cost" to be adjusted or increased because of the operation of SFAS 143 involves, quite simply, impermissibly rewriting the statute. The concept of "original cost" in G.S. 62-133(b)(1) matters, since pursuant to G.S. 62-133(b)(4), a return is allowed only on the cost of plant that has been computed in accord with G.S. 62-133(b)(1).

A second difficulty arises from considering the overall structure of G.S. 62-133(b) in the context of accounting practice and procedure as it existed at the time the statute was enacted. G.S. 62-133(b)(1) and (b)(3) adopt and incorporate in their workings the concept of "depreciation." Accumulated depreciation reduces the amount computed under subsection (b)(1), which is the amount upon which a return may be earned, and depreciation is recovered as an operating expense, without return, under subsection (b)(3). As has already been discussed at length earlier, under traditional depreciation accounting the costs that will be incurred upon retirement of a long-lived asset ("costs of removal") are incorporated into depreciation expense as part of the calculation of terminal net salvage value. In this manner, they are recovered for ratemaking purposes as an

[52] It is also a reversal of the position taken in the Commission's August 8, 2003, Order in Docket No. E-7 sub 723. In that Order the Commission approved the Company's implementation of SFAS 143 accounting treatment for its obligations arising from decommissioning the irradiated portions of its nuclear plants and for environmental clean-up at its Belews Creek Steam Station. The Commission conditioned its approval on a number of specific qualifications and limitations, including "[t]hat no portion of the total ARO asset or liability shall be included in rate base for North Carolina retail accounting or ratemaking purposes."

operating expense pursuant to G.S. 62-133(b)(3), without a return, and not as "used and useful plant" entitled to a return.

SFAS 143 changes the time of recognition of costs of removal, in certain cases, for purposes of balance sheet presentation. It does this so that readers of financial statements may better understand expected future expenditures that will be associated with an asset.[53] Under SFAS 143 treatment the ARO and ARC entries substitute for and replace on the financial statement what had previously been shown on the financial statement as the cost of removal component of accumulated depreciation, reported as a "contra asset." Because these new entries are intended to be only a change for financial statement reporting purposes, they should be given the same treatment for ratemaking purposes as the cost of removal component of accumulated depreciation expense that they now replace. To afford any different treatment for ratemaking purposes would be, again, to allow the statutory structure and language of G.S. 62-133(b) to be amended by action of the Financial Accounting Standards Board. Whether or not such an amendment is desirable as a matter of policy, I do not believe it is within the power of the Commission to sanction it absent legislative action by the General Assembly. Because I differ with the majority and believe that under G.S. 62-133(b) the classification of costs – that is, whether they be property used and useful in providing service or whether they be operating expenses – is dispositive for purposes of eligibility to earn a rate of return, I dissent from the determination that the mere fact an item of expenditure has been reported on the financial statements as part of an asset retirement cost adjustment under SFAS 143 entitles the Company to earn a return on that expenditure.

Nor do I believe the Financial Accounting Standards Board contemplated the result arrived at by the majority here when it promulgated SFAS 143. Explaining the difference between SFAS 143 treatment and prior practice under SFAS 19, the official FASB publication promulgating the new standard explains:

> Under Statement 19, dismantlement and restoration costs were taken into account in determining amortization and depreciation rates. Consequently, many entities recognized asset retirement obligations as a contra-asset. Under this Statement, those obligations are recognized as a liability. Also, under Statement 19 the obligation was recognized over the useful life of the related asset. Under this Statement, the obligation is recognized when the liability is incurred.

With respect to the relationship between the new treatment of asset retirement obligations under SFAS 143 and the treatment of those same obligations for rate-regulated entities, the Statement explains in Paragraph 21:

> The capitalized amount of an asset retirement cost shall be included in the assessment of impairment of long-lived assets of a rate-regulated entity just as that cost is included in the assessment of impairment of long-lived assets of any other entity. FASB Statement No. 90, *Regulated Enterprises –*

[53] Statement of Financial Accounting Standards No. 143 (June 2001) pp. 4-5.

Accounting for Abandonments and Disallowances of Plant Costs, applies to the asset retirement cost related to a long-lived asset of a rate-regulated entity that has been closed or abandoned.

Parsing through this language is not especially easy, but in plain English it says in substance the following: the capitalized amount of an ARO liability, i.e., the amount of the increase in the carrying cost of the long-lived asset on the asset side of the balance sheet, is to be given the same treatment as provided under SFAS 90 for a long-lived asset that has been closed. SFAS 90 is lengthy and detailed, but for present purposes the basic summary statement found in Paragraph 3 of the official statement suffices to make the point:

> When it becomes probable that an operating asset or an asset under construction will be abandoned, the cost of that asset shall be removed from construction work-in-process or plant-in-service. The enterprise shall determine whether recovery of any allowed cost is likely to be provided with (a) full return on investment during the period from the time when abandonment becomes probable to the time when recovery is completed or (b) partial or no return on investment during that period. *That determination should focus on the facts and circumstances related to the specific abandonment and should also consider the past practice and current policies of the applicable regulatory jurisdiction on abandonment situations.*[54]

Paragraph 20 of SFAS 143 makes essentially the same point:

> Many rate-regulated entities currently provide for the costs related to the retirement of certain long-lived assets in their financial statements and recover those amounts in rates charged to their customers. Some of those costs result from asset retirement obligations within the scope of this Statement; others result from costs that are not within the scope of this Statement. The amounts charged to customers for the costs related to the retirement of long-lived assets may differ from the period costs recognized in accordance with this Statement and, therefore, may result in a difference in the time of recognition of period costs for financial reporting and rate-making purposes. An additional recognition timing difference may exist when the costs related to the retirement of long-lived assets are included in amounts charged to customers but liabilities are not recognized in the financial statements. If the requirements of Statement 71 are met, a regulated entity shall also recognize a regulatory asset or liability for the differences in the timing of recognition of the period costs associated with asset retirement obligations for financial reporting pursuant to this Statement and rate-making purposes.

[54] Statement of Financial Accounting Standards No. 90 (December, 1986), pp. 5-6.

Two things are noteworthy about this Statement. First, it is an explicit recognition that the treatment of costs under SFAS 143 for financial statement reporting purposes may be different than the treatment of those costs for ratemaking purposes. Second, it expressly confirms that SFAS 71 continues to apply to the accounting treatment of such differences in treatment through the mechanism of regulatory assets and regulatory liabilities.[55]

The upshot of this is that under SFAS 143, SFAS 90 and SFAS 71, which must be read together, the capitalized amount of an asset retirement cost, that is, the increase in the carrying cost of the asset equal to the amount of the ARO liability, may or may not, if it becomes an allowed cost for recovery in rates, carry a return *depending on the policies and practices applicable in a particular regulatory jurisdiction.* I read from this no intention in SFAS 143 that for a rate-regulated entity the accounting treatment of an asset retirement obligation, including the capitalization of the amount in the carrying cost of the associated asset, is to supersede or modify either the law, policy, or practice of any jurisdiction with respect to what items of cost may earn a return.[56]

Finally, I note that FERC Order 631, adopting SFAS 143 principles for entities subject to FERC jurisdiction, likewise does not compel inclusion of the capitalized amount of the asset retirement obligation in rate base; quite the contrary. Order 631, adopted on April 9, 2003, amended Title 18 of the Code of Federal Regulations to add a new section 35.18(a) that reads in full:

> A public utility that files a rate schedule, tariff or service agreement under §35.12 or §35.13 and has recorded an asset retirement obligation on its books must provide a schedule, as part of the supporting work papers, identifying all cost components related to the asset retirement obligations that are included in the book balances of all accounts reflected in the cost of service computation supporting the proposed rates. *However, all cost components related to asset retirement obligations that would impact the calculation of rate base, such as electric plant and related accumulated depreciation and accumulated deferred income taxes, may not be reflected in rates and must be removed from the rate base calculation through a single adjustment.*

(emphasis added)

[55] It is, of course, the case that not all regulatory assets or liabilities carry with them an associated rate of return. Whether they do so or not is, once again, a function of the provisions of G.S. 62-133.

[56] In October 2002, the Edison Electric Institute and the American Gas Association issued an industry paper titled "Asset Retirement Obligations Implementation Issues." Speaking to the effect of SFAS 143 on ratemaking, the paper observes (p. 5): "Many utilities have included removal costs in depreciation rates or some other rate recovery mechanism. For ratemaking purposes, the collection of depreciation expense, including the salvage, and grow removal cost should remain intact. If customers have been paying for the cost of removal through rates, they may have a reasonable expectation that the utility will expend the costs to remove the asset at the end of its useful life."

The intent of this new rule is explained by FERC in Paragraph 62 of Order 631, which states: "To ensure that all rate base amounts related to asset retirement obligations can be identified and excluded from the rate base calculation in a rate change filing, the Commission adds §§ 35.18 and 154.315 [dealing with jurisdictional natural gas entities] to its rate change filing requirements," and later in the same paragraph repeats the point, stating: "…[T]he regulations require that all asset retirement obligations related rate base items be removed from the rate base computation through an adjustment."

I therefore disagree with the majority order and would find that classification of costs and expenses – either as "used and useful property" or as "reasonable operating expenses" -- *does indeed* matter for purposes of applying G.S. 62-133(b)(4) and (b)(5). SFAS 143 does not pre-empt that choice.

B. The Four Retired Plants and Their Ash Storage and Disposal Facilities

Coal-fired generating units at four of the Company's plants were retired and were in decommissioning status at the time this rate case was filed. These include Buck units 1 through 6 (retired in 2013)[57], Dan River units 1 through 3 (retired in 2012), Riverbend units 4 through 7 (retired in 2013) and W.S. Lee units 1 through 3 (retired in 2014), and these units had been removed from plant in service. Kerin Direct Ex. 4 (Ex. Vol. 16, Part 1, p. 9.) Except for the units at the W.S. Lee plant, to which CAMA does not in any event apply, the coal-fired units at all four plants were retired and decommissioning activities had commenced or were in planning stages before the enactment of CAMA; all units were retired before final adoption of the federal CCR Rule, and all were likewise retired before the entry of the Company's plea in the federal criminal cases. See Ex. Vol. 16, Part 3, pp. 175-308. None of these retired units and none of the waste ash storage and disposal units associated with them will be used to provide any future service to ratepayers of the Company. With respect to the costs for decommissioning and closure of the waste ash facilities at these four plants and independently of all other reasons for disallowance of a return discussed in this portion of my opinion, I believe the Supreme Court's decision in State ex rel. Utilities Comm'n v. Carolina Water Service, 335 N.C. 493, 439 S.E.2d (1994) (Carolina Water Service), prohibits allowing any return on deferred unamortized costs associated with the decommissioning and closure of the waste ash storage and disposal units at the Buck, Dan River, Riverbend and W.S. Lee plants. In the present case the costs requested for deferral and amortization for the waste coal ash facilities at these plants totals $ 392,837,165. Kerin Direct Ex. 10 (Ex. Vol. 16, Part 1, pp. 22-23).[58] For perspective, the total costs requested for deferral and amortization at all the Company's operating and retired plants totals $731,850,458, meaning that the costs associated with waste units at the retired plants comprise 53.68% of the total request. Id.[59]

[57] Buck units 1 and 2 had been retired some years earlier. Units 3 and 4 were retired in 2011 and units 5 and 6 were retired in 2013.

[58] The numbers provided by the Company in this exhibit are systemwide and do not reflect only the North Carolina retail portion.

[59] See the preceding footnote.

I am not persuaded by the majority's attempt to distinguish Carolina Water Service from the instant case. The majority attempts to diminish the holding of the case by observing that recovery of a return on retired plant was not "the major issue in the case" and that discussion of the issue occupied only two pages out of a lengthy opinion. Majority Order at fn. 64. This is pure makeweight. I submit that the holding was succinctly stated by the Court because the principle of law does not require an elaborate or extended analysis. It is next observed that the costs at issue were that portion of the original investment in the wastewater treatment plant that had not been recovered through depreciation and that in this case the costs the Company seeks to recover are new costs incurred in 2015 through 2017. Again, I believe the attempted distinction fails. As has already been discussed elsewhere in this dissenting opinion, the costs to close the waste storage and disposal units at the four retired plants are properly costs of removal to be recovered through depreciation rates as an element of terminal net salvage value. The *outlays or expenditures* for these costs may have been made in 2015 through 2017, but the *costs* – costs of removal, or depreciation expense -- were incurred and are properly allocable over the operating life of the waste facilities. In the present case, some of the coal-fired plants and associated waste ash facilities were retired earlier than their anticipated useful lives (e.g., Buck and Riverbend); others were retired at the end of their expected lives (e.g., Dan River). What matters under Carolina Water Service is that the plants and their associated waste ash facilities were not at the time this rate case was filed and never would be in service again.[60] They were not at the time of this case "property used and useful, or to be used and useful within a reasonable time after the test period, in providing the service to be rendered to the public within this State…." G.S. 62-133(b)(1).

An argument has been advanced that these retired ash basins remain "used and useful" because they provide environmentally safe permanent disposal of waste ash for the protection of, among others, the Company's ratepayers. I consider this argument creative fiction. These basins contain ash residue from the burning of coal to provide electricity service to ratepayers before the retirement of the generating plants which they serviced. A fair reading of G.S 62-133(b) is to the effect that property "used and useful" upon which an investment return may be earned must be committed to the provision of utility services to present and future customers, not a prior generation of customers. I do not dispute that the costs of completing decommissioning and closure of the basins and thereafter of maintaining and monitoring them are recoverable as reasonable expenses of operation pursuant to G.S. 62-133(b)(3), but it strains common sense that they are in

[60] In Footnote 64 of the Majority Order, an effort is made to characterize the waste surface impoundments as a "class" of property for purposes of determining such matters as useful life, depreciation, and retirement from service, as if they were akin to such items as poles, conductors, and transformers. There is simply no support in the record for this attempt. The overwhelming weight of the evidence demonstrates that the ash basins were each treated and dealt with by the Company as individual units associated with their respective generating plants. The attempt to argue that they are "mass" or "class" assets on this record stands on no better ground than would an attempt to argue that all the Company's coal-fired generating units taken together constitute a single "class" for purposes of ratemaking treatment.

any respect providing the "service" to present and future customers that is contemplated by G.S. 62-133(b)(1). Moreover, I note that to the extent this argument has merit, which I do not believe it has, *even by its own terms* it can apply only to newly constructed landfills or other waste disposal units that will provide permanent storage for waste ash as part of the closure of the existing waste storage facilities. For example, surface impoundments, such as the primary and secondary ash basins at Dan River or the primary and secondary ash basins at Riverbend, or the three ash basins at Buck, all of whose waste contents will first be excavated and then removed from them before the basins are closed cannot be said to be providing thereafter any service to present or future customers.

I have also considered whether it may be the case that the ash basins at the retired generating plants may remain in use for purposes other than temporary storage of coal combustion wastes, but the record does not answer this question. Some of the Company's waste impoundments were used to treat other low-volume waste streams, from plant processes other than burning coal for the generation of electricity. During the hearing on the application the Company was asked to provide a late-filed exhibit showing the date use of each of the surface impoundments for these other waste streams ceased. From the exhibit filed by the Company an answer to this question of other use cannot be derived.[61] With the exception of the inactive ash basin at the W.S. Lee plant, the 1977 inactive ash basin at the Cliffside plant, and the primary ash basin at the Dan River plant the late-filed exhibit reported that all other ash basins at the four retired plants (Buck, Dan River, Riverbend, and W.S. Lee) were still receiving process wastewater "and/or" "stormwater (considering gravity flow as stormwater inflow)". Because the exhibit included not only the four retired plants but the four operating coal-fired plants and because it was not provided until after the close of the hearing, it is impossible to unpack this "and/or" phrase as to any individual waste impoundment. Even if it were assumed that stormwater (and groundwater, i.e., gravity flows) continues to flow into the retired ash basins, this is a function of the fact that the impoundments have not been finally covered or capped and that closure is not yet complete. It is not an indication that the impoundments will continue to be "used and useful" into the future as ongoing "stormwater treatment units." Accordingly, I find that the Company's Kerin Direct Ex. 5 (Ex. Vol. 16, Part 1, p. 10) establishes the dates of final use of the ash basins at the Buck (2013), Dan River (2012), Riverbend (2014), and W.S. Lee (2014) plants.[62] Those dates all precede the filing of this case.

[61] Pursuant to a request I made on the record during the evidentiary hearing, the Company, through its counsel, filed this late-filed exhibit on April 2, 2018, containing a spreadsheet containing the information discussed here.

[62] These dates are identified on the exhibit as dates basins were "closed," but witness Kerin explained that this does not refer to closure for regulatory purposes but the date the impoundment ceased receiving wastes for treatment and storage. Tr. Vol. 16, pp. 43-47.

C. All Plants – Separating Sheep from Goats

The argument in the prior section applies only to those waste ash facilities at the coal-fired plants that were retired prior to 2015.[63] In this section I address issues that arise in the case of all plants, operating and retired. Proper characterization of the costs the Company is seeking to recover for ash basin closure activities at its plants is essential for application of the ratemaking provisions in G.S. 62-133(b). On the record in this case that is a difficult, if not in part impossible, assignment. Part of the difficulty is a function of the different stages in which the closure process now stands at each of its plants and for each of the waste ash units and the different rates at which closure activities are progressing. Another part is the difficulty of reconciling the listing of the tasks for which cost recovery is sought in this case with historical documentation of ash basin closure tasks already undertaken by the Company in periods prior to 2015, the first year for which cost recovery is being requested in this case. Yet a third portion of the difficulty is the opaqueness of the task descriptions in the pertinent exhibits and evidentiary submissions themselves.

Kerin Direct Exhibits 10 (Ex. Vol. 16, Part 1, pp. 22-23) and 11 (Revised Kerin Ex. 11, filed by DEC on March 22, 2018) are the core exhibits summarizing the request for cost recovery in this case. For each of the retired and operating plants, Exhibit 11 sets out a summary of categories of expenditures, both actual for 2015, 2016 and 2017, and forecast for later years. I use the portion of Exhibit 11 that speaks to the Allen plant, an operating plant, for illustration. The categories fall into two groups. The first group includes: (1) mobilization and site preparation, (2) site infrastructure, (3) water treatment & management, (4) ash processing, (5) construct landfill & cap-in-place, (6) site restoration, demobilization, closing, (7) engineering closure plans, (8) a category designated as "Duke Cost," (9) site maintenance landfill, etc., and (10) contingency. These ten categories of costs are grouped together in a summary subtotal titled "Basin Closure." A second group of items consists of a group of eight other categories of costs, including (1) CCP[64] basin support projects, (2) CCP oversight & LRP, (3) CCP inspections and maintenance, (4) CCP engineering, (5) EHS, (6) post-closure maintenance, (7) previous landfill ARO cash flows, and (8) inflation impacts.

[63] The position I have taken with respect to the closed generating units could be extended to include the former ash impoundments at the four operating coal-fired plants – Allen, Belews Creek, Cliffside, and Marshall -- that were removed from service long in the past. These would include the 1957 ash impoundment at the Allen plant, which was closed in 1973 and the 1957 and 1970 ash basins at the Cliffside plant, which were closed in 1977 and 1980, respectively. This is in fact the position I adopted in dissent in the DEP Rate Case Order. The Company advised, in response to a question on the point, that it could not present a separate accounting for closed or inactive impoundments apart from the closure costs incurred and expected to be incurred for the remaining active impoundments. Tr. Vol. 16, p. 52; DEC Response to Commission Request Regarding ARO, filed April 6, 2018. While witness Garrett was able to obtain some separate data for the inactive ash basin and the borrow area at the retired W.S. Lee plant, the same level of detail is not present in the record for the retired basins at any of the operating plants.

[64] "CCP" is shorthand reference for "coal combustion products," otherwise known as wastes left from burning coal.

Page 8 of Kerin Direct Exhibit 11 contains footnotes for these categories, but it provides only marginally more information than the titles of the categories themselves suggest. A number of the categories can be understood from the testimony of witness Kerin or other witnesses in the case. For example, "CCP inspections and maintenance" appears to refer to ongoing maintenance activities relative to the surface impoundments, including such tasks as maintaining the integrity of dikes and dams, preventing vegetation encroachment, maintaining risers and discharge piping, and similar. "EHS" appears to refer to an allocation of the costs for the Company's general Environmental Health and Safety department, but the footnote suggests that it also includes "well installation, well sampling (groundwater monitoring), bottled water and permanent water supplies provided to nearby residents." "Construct landfill & cap-in-place" is fairly straightforward; it captures the costs to construct a new permitted landfill or to cap-in-place an existing unit. The categories titled "water treatment and management" and "ash processing," based on the testimony of witnesses Kerin, Garrett, Moore, and Wells, likely involves dewatering of ash in an impoundment, consolidating the ash and preparing it for removal, excavation of the ash, and transport to another location for final disposal. The category "inflation impacts" shows the expected increase in costs for tasks that will not be undertaken until later years in the period covered by the exhibit (2015 through 2057). Other categories are more opaque. For example, how do the tasks embraced within the category "CCP Basin Support Projects" differ from those in such categories as "CCP Oversight and LRP," or "CCP Engineering," or for that matter, what is included in "CCP Engineering" that is not included in "Engineering Closure Plans"? Finally, other categories, most notably the one titled "Duke Cost" remain a complete mystery; all that can be said with any certainty is that it represents costs that do not fall within one of the other enumerated categories.

I am mindful of the principle that we take the amounts recorded in the Company's books as they are given and do not look behind them unless a specific challenge is made to some item of expense or revenue.[65] The issue here presented, though, does not involve questioning the amounts reflected on Kerin Direct Exhibits 10 and 11 but rather deciding, for ratemaking purposes, which of those amounts represent investments for which the Company may earn a return and, on the other hand, those which are in the nature of expenses of operation and maintenance. Even within the first grouping of expenditure categories, those summarized as "Basin Closure," proper characterization is somewhat difficult. "Water treatment and Management" appears to refer to the process of decanting standing water and dewatering the ash in the basin. "Ash Processing" appears to refer to consolidation and stacking of the dewatered ash in order to reduce the area footprint that will require capping and vegetation or, if the ash is to be excavated, consolidating it for more efficient transport, or perhaps treating it for purposes of beneficiation.

[65] Agreeing with the Company's proffer, Public Staff witness Moore testified that based on his review of the costs incurred in 2015, 2016 and 2017 for the ash basins at the four operating plants -- Allen, Cliffside, Belews Creek, and Marshall -- were reasonable and prudent, and I am not contesting this judgment. Again, the issue is how those costs should be characterized for ratemaking purposes.

From the available evidence I conclude that the costs for which recovery is sought in this case include a significant mixture of costs that are correctly characterized as operating and maintenance expense, and another portion that might be considered investment in capital assets required for basin closure. In the case of the Allen plant, which I have used as an illustration, most of the expenditures for the years 2015, 2016 and 2017 are recorded in categories that appear more appropriately considered operating and maintenance expenses, especially since the ash basin at the Allen plant remains active and actual closure has not yet commenced. For example, during the period 2015 through 2017, none of the costs incurred at the Allen plant have been for such activities as "mobilization and site preparation," "site infrastructure," "ash processing," "construct landfill & cap-in-place" or "site restoration, demobilization and closing," which are categories that it might be argued are capital in nature and potentially eligible for a return. For 2015 and 2016, of the total requested cost recovery of $32,663,754, some $28,908,681 is recorded in the categories "EHS," "CCP oversight and long range planning," and "CCP basin support projects." Only $3,755,073 is recorded in the large subgroup of categories headed "Basin Closure," and of this total $2,457,590 (or 65.45% of the total) falls within the mysterious category labelled "Duke Cost."[66]

The problem can also be illustrated by a different example. For the period 2015 through 2017, the period for which cost recovery or deferral and amortization are sought in this case, total costs incurred for closure activities at the Dan River Steam Station were $143,237,755, and total costs incurred for closure activities at the Riverbend Steam Station were $220,273,249. Kerin Direct Ex. 10 (Ex. Vol. 16, Part 1, pp. 22-23.)[67] These are the two sites ranked high priority under CAMA, and together these two plants account for 49.67% -- just under one-half -- of the Company's total expenditures on all its waste ash storage and disposal facilities during the period. Based on the information that can be extracted from Revised Kerin Direct Ex. 11 (filed by DEC on March 22, 2018), interpreted in light of witness Kerin's testimony, the testimony of witnesses Garrett and Moore, and documentary exhibits, the principal activities conducted at these two plants included excavation, transport and offsite disposal of ash fill area 1 at the Dan River plant, dewatering ash in the primary and secondary surface impoundments at Dan River, excavation and transport of ash from the ash stack at the Riverbend plant to Roanoke Cement Company and the Brickhaven mine, dewatering the primary and secondary ash basins at the Riverbend plant, and beginning excavation and transport of ash from the primary and secondary ash basins at the Riverbend plant for offsite disposal. I do not believe these activities can be under any reasonable interpretation of G.S. 62-133(b)(1) considered investments in plant or facilities used or useful to provide electric service to present and future customers. [68] They are under any common understanding of the terms, expenses of operating and maintaining the (retired) coal-fired generating plants.

[66] In this example I do not include the figures for 2017, since they are projected numbers on Kerin Ex. 11.

[67] The data in this exhibit were presented on a systemwide basis and do not represent the North Carolina retail allocation. For present purposes, however, that point is not material.

[68] The Company plainly knows how to characterize an expenditure as "capital" versus "operating." On Kerin Direct Ex. 11, the costs to purchase the equipment necessary for preparing ash excavated from

I use this second example because the elements of cost involved are fairly straightforward and are, on this record, a very large proportion of the total expenditures for which recovery is being allowed by way of deferral and amortization. The point of all the foregoing is that the assumption made in the majority order that *all* of the costs incurred and yet to be incurred are "assets" or are "investments" that are "used and useful" simply cannot withstand a more granular examination and consideration of the specific items of cost and their nature. I believe it is error to conclude that simply because the costs incurred by the Company relate, in some manner, to present or former waste surface impoundments, they therefore constitute expenditures or investments for which a return is authorized by G.S. 162-133(b)(1). Sorting out those costs that represent an investment in "used and useful" plant and equipment from costs that represent either ordinary or extraordinary expenses of operation requires a plant-by-plant, waste unit-by-waste-unit, task-by-task inquiry and evaluation.[69] This the Majority Order does not do, instead lumping all tasks, all waste units, all time periods, and all plants together and allowing a return on the expenditures without further qualification, except only the reduction of that return by $70 million. I further believe that this outcome is largely the result of the erroneous determination that it is unnecessary to engage any such exercise because of the Company's adoption of SFAS 143 accounting for its coal ash expenditures. the Even if the Commission has discretionary authority to allow a return on the unamortized portion of the amounts expended from 2015 through 2017, I do not believe its exercise of that discretion in such an undifferentiated and summary fashion is proper.

D. Working Capital .... or Not?

As did its affiliate in the DEP Rate Case, the Company here attempts to argue that its expenditures for closure of the waste ash impoundments have been financed from shareholder funds provided for working capital and that they are therefore eligible for a return under the holding in State ex rel. Utilities Comm'n v. Virginia Electric & Power Co., 285 N.C. 398, 206 S.E.2d 283 (1974) (VEPCO). I note that the Company's presentation of evidence on this point differs in no material way from the presentation made by its affiliate in the DEP Rate Case, and I find it no more persuasive here than in that proceeding. The calculation of working capital set forth in witness Doss Direct Ex. 2 (Ex. Vol. 12, p. 786) contains no amounts designated as needed for additional working capital due to coal ash costs, and the Company's position I believe rests on nothing more than an *ipse dixit*.

In this case I find in the evidence an additional reason for rejecting the Company's position. As the Court made clear in VEPCO, not all funds that are functionally used as

the impoundments at the Buck Steam Station for beneficial reuse is specifically denominated in a separate category titled "Capex – Equipment and Facility Cost."

[69] This is not an impossible task. It is one the Company knows very well how to perform. For example, in its 2008 Coal Combustion Products Ten-Year Plan, Kerin Public Staff Ex. 2, Vol. 16, Part 1, p. 47 and *passim*, the Company prepared elaborate budgets for planned expenditures for its coal ash storage and disposal facilities, classifying those expenditures as either "Capital," "O&M," or "Risk," the latter term possibly referring to the "risk" that they might not be recoverable in rates.

working capital are investor provided funds on which a return may be allowed; funds provided by ratepayers to cover anticipated expenditures not yet incurred may be used by the Company in the interim as working capital, and such funds are not eligible for a return. Id. at 415, 206 S.E.2d at 293.

Due to the enactment of the Federal Tax Cuts and Jobs Act of 2017 the evidence shows that the Company has collected from ratepayers an amount presently estimated to be in the order of $953 million in unprotected EDIT that it will not now be required to pay to the federal government in taxes. (Revised McManeus Workpapers, Schedule 1-4, Line 2, Column (b), and Schedule 1-5, Line 8, filed by DEC on April 19, 2018.) This amount must now be returned to ratepayers. In the Matter of Tax Reform Act of 1986, Docket No. M-100, Sub 113, 82 P.U.R.4th 234, 234-35 (Oct. 23, 1986), aff'd, State ex. rel. Utilities Comm'n v. Nantahala, 326 N.C. 190, 197, 388 S.E.2d 118, 122 (1990). In the interim, these funds represent precisely the type of "ratepayer provided working capital" about which the VEPCO court spoke.

The final number of such excess deferred income taxes will be refined as the Company does further analysis of the actual effect of the new tax legislation. Because this development occurred after the test year for this case, after the rate case was filed, and on the eve of the hearings on the Company's application, the Commission has concluded that disposition of this excess amount collected from ratepayers in anticipation of taxes that will now not be paid should be deferred until the Company's next general rate case and placed in a regulatory liability account in the interim. I support this disposition. For present purposes, however, the important fact is that the Company will have the use of these ratepayer provided funds as "working capital" until such time as they are returned to ratepayers in the manner provided in the Company's next general rate case. The final amount, even after refinement, will be substantial, and I find it impossible on this record to conclude that in order to finance its costs to close its waste coal ash impoundments between now and the time of its next general rate case the Company either has been or will be, in the near term, using shareholder provided funds instead of or to the exclusion of ratepayer funds such as the amount represented by this regulatory liability item.

E. A Final Matter of Policy

Ash wastes are a residue from the burning of coal to generate electricity. Supplying electricity is the service for which the Company is entitled to compensation, and the investments it makes in plant and facilities in order to supply that service are the capital assets on which it is entitled to earn a return. There is no dispute that the cost of the coal burned is an operating expense incurred in order to deploy those capital assets to provide electric service. It stands this paradigm on its head to allow the Company to treat the residue from this fuel as a new opportunity for capital investment and for profit-making. The fuel itself has real value for the provision of a desired service, electricity; surely the unwanted residue, except when committed to beneficial reuse, has no such value. Yet under the majority's analysis, the residue has now become of greater profit-making value to the Company than the underlying fuel itself. We are in the waning years of the Company's use of coal as a fuel, but even so the Allen, Marshall, and Cliffside coal-burning units will continue to consume prodigious quantities of coal for over a decade to come. The cost of that coal will be reliably recovered, without profit, in the Company's general rates and through the fuel adjustment rider. What the majority does today, however, creates an undesirable incentive with respect to the use of that coal. Different coals burn with different degrees of efficiency and generate different quantities and qualities of waste as per unit of coal burned. Is there now to be an opportunity for earning an increased profit by purchasing lower quality coal or coal that leaves more residue or residue more expensive to manage, thereby generating higher disposal costs when the ash basins at the still-operating plants are finally retired? These costs will form the basis upon which additional profit may be earned. This is an unacceptable and even absurd result, and I do not suggest that the Company would intentionally pursue such a course. However, this "thought exercise" illustrates the type of error into which I believe the majority has fallen by allowing recovery of a return on the deferred costs of permanently disposing of the waste ash. I believe the General Assembly in Chapter 62 intended to provide an opportunity for companies to earn a return on the provision of a valuable service – electricity. It did not intend to establish that scheme in order to encourage investment in waste management enterprises.

In summary and for all the foregoing reasons I find that on the present record the deferred portion of allowed costs attributable to closure of the waste ash storage and disposal facilities are ineligible for allowance of a rate of return. It is not necessary for me to say anything further about the "mismanagement penalty" assessed in the Majority Order because there is nothing to which that "penalty" attaches.

III. Increase in Basic Facilities Charge (BFC) and its Applicability Only to the Residential Class of Ratepayers

The majority's decision to permit an increase in the fixed monthly billing charge for residential rate classes, but not for any of the other customer rate classifications, I consider one of the more peculiar aspects of the decision, and I dissent from that portion of the findings and order that authorizes the increase. While in the final outcome the Commission has determined that the Company's revenue requirement should be reduced, and I concur generally in that result, although based on issues discussed in this dissent, I would find and am of the opinion that the revenue requirement should be lower than that determined by the Commission majority. Despite the evidence and issues addressed elsewhere in this dissenting opinion which support a further reduced revenue requirement, the majority approves an increase in the fixed monthly charge affecting only the residential customers.

The majority does not support its determination with any findings or evidence showing that the Company's fixed costs to serve residential customers has increased over what is supported by the revenues upon which the Company's present rates are based. It does not make findings or point to any evidence that the fixed costs to serve residential customers have increased relative to costs of service for non-residential customers. While not granting the full amount of increase requested by the Company for the residential rate class, the majority rejects altogether the Company's request for an increase in the fixed monthly charges applicable to non-residential rate classes, without offering a compelling reason, nor a reason which is supported by the record in this case, for such different treatment. I acknowledge that these observations are all about cost of service and that the matter of setting the fixed monthly component of rates is a matter of rate design. However, if there is no demonstrated need for additional revenue to be provided from residential ratepayers, other justifications for the increase must be found. Moreover, to support such a difference in treatment between the residential and non-residential classes, there must be justifications peculiar to the residential rate classes and not applicable to the non-residential rate classes. I believe the majority's justifications, to the extent they are articulated at all, are without basis in the record.

The only grounds of justification for the increase in the residential fixed charge portion of the residential rates to be gleaned from the majority order are 1) the unsupported easing of subsidization between members of the residential class and 2) the acceptance of the Company's assertion that, based on the "minimum system" method for the allocation of the customer portion of distribution plant costs, the present residential monthly fixed charge is lower than the actual fixed charge caused by the residential class of customers. Dealing with the grounds separately, the majority's subsidization justification for increasing the fixed monthly charge for residential customers is set forth in a single sentence:

> The increase in these schedules minimizes subsidization and provides more appropriate price signals to customers in the rate class, while also moderating the impact of such increase on low-income customers to the extent that they are high-usage customers such as those residing in poorly insulated manufactured homes.

Majority Order at 112. That is it; all else is based on alleged cost causation, i.e., that the current fixed charge does not accurately reflect the Company's fixed costs of serving residential customers. The "subsidization" referred to here is alleged subsidization by high usage customers of the low usage customers, the latter category including, among others, customers who have aggressively implemented energy efficient measures and may even be self-generating a portion of their own electricity needs. A contrast is drawn between these low usage customers and the high usage customers, such as "those residing in poorly insulated manufactured homes," who are allegedly subsidizing the low use customers through energy charges artificially inflated by a fixed charge that is too low. The difficulty with this picture is that it is conclusory and simply without evidentiary support in the record. Indeed, the only evidence offered by any party in an attempt to characterize who are the "low users" and who are the "high users" was offered by NC Justice Center, et al. witness Howat, whose evidence was to the effect that the population of low-use customers tends to have a higher proportion of low-income, elderly, and African-American ratepayers; not that low income customers reside in poorly insulated homes or are high energy users as asserted by the majority. It is not necessary to decide for the present whether Howat's evidence is correct, only to point out that the majority has no evidence to support any contrary picture or the majority's stated (stereotypical) presumption that low income customers are high energy users subsidizing low energy users.[70]

This then leaves the majority with only its "cost causation" justification for the increase in the residential fixed charge. As I have already noted, the Commission in prior rate orders has recognized that cost allocation and rate design are separate topics, and the parties continue to pay homage, at least in principle, to this distinction. Nonetheless, with respect to setting the fixed component of monthly customer bills, a matter of rate design, it is apparent that the positions of the contending parties are largely determined by their views concerning the propriety of using the so-called minimum system method for allocating the customer portion of distribution plant costs. In past rate cases the Commission has permitted the Company to use the minimum system method for purposes of deriving the customer portion of embedded distribution system costs, but it has expressly stated that the results yielded by that method do not and should not dictate the level of the per customer fixed monthly charge. See, e.g., Order Granting Partial Increase in Rates and Charges, Docket No. E-2, Sub 526, at pp. 29-30. Moreover, there are other considerations, aside from costs, that go into rate design, including setting the fixed charge portion of the rate. See DEP Rate Case Order at 107-08, 114 (acknowledging that factors other than cost of service are appropriate to consider and balance in rate design). In the present case the majority takes the further positive step of directing the Public Staff to initiate discussions with the regulated electric utilities to explore in greater depth the use of the minimum system method and alternative methods for allocating distribution system costs and to submit a report to the Commission by March 31, 2019.[71]

For myself, while I will consider the report and any other evidence that may be properly introduced, I am concerned that the time has come or may have come to divorce, explicitly and completely, the setting of the fixed monthly charge from any association with the minimum system methodology used for allocating embedded distribution system costs. It may be that the minimum system method should be rejected entirely as both a tool for cost allocation and, as a necessary consequence, as an indirect determinant of the per customer fixed monthly charge.[72] The reasons for abandoning use of the minimum system method have been ably briefed by several of the intervenors, including

[70] Moreover, if the majority's expressed concerns about subsidization are legitimate, the Company's request in this general rate case to increase the fixed charge portion of the rate applicable to the non-residential classes would indicate that the current non-residential rates are not properly balanced between fixed charges and demand charges, and the Commission should have the same interclass subsidization concerns with respect to non-residential customers. However, the majority discriminatorily disregards, without explanation or justification, the issue of subsidy for all but the residential class of customers and does not impose any fixed charge increase on nonresidential customers to ease the impact of alleged subsidization.

[71] Part of the majority's rationale for taking this step relies on language taken from my dissent in the DEP Rate Case. Based on continued study of the issue since that time and the additional evidence taken in this case, my position has now become more firm on the subject, especially in light of the result in this case concerning the residential fixed monthly charge.

[72] I would do this for all customer classes, not just the residential rate classes.

NCSEA and the NC Justice Center, et al., and are powerfully supported by the testimony of witnesses Barnes and Wallach. The Company's defense of the minimum system method rests almost entirely on history and custom, supplemented by the fact that the minimum system is one among several recognized methods for allocating the embedded costs of distribution system plant and facilities among rate classes. Tr. Vol. 19, pp.34-35.

The method has been persuasively condemned on conceptual grounds, one of the more notable critics being Professor Bonbright, who in his 1961 treatise observed:

> [T]he really controversial aspect of customer-cost imputation arises because of the cost analyst's frequent practice of including, not just those costs that can be definitely earmarked as incurred for the benefit of specific customers but also a substantial fraction of the annual maintenance and capital costs of the secondary (low-voltage) distribution system – a fraction equal to the estimated annual costs of a hypothetical system of minimum capacity. This minimum capacity is sometimes determined by the smallest sizes of conductors deemed adequate to maintain voltage and to keep from falling of their own weight. In any case, the annual costs of this phantom, minimum-sized distribution system are treated as customer costs and are deducted from the annual costs of the existing system, only the balance being included among those demand-related costs to be mentioned in the following section. Their inclusion among the customer costs is defended on the ground that, since they vary directly with the area of the distribution system (or else with the lengths of the distribution lines, depending on the type of distribution system), they therefore vary indirectly with the number of customers. What this last-named cost imputation overlooks, of course, is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile or per square mile). Indeed, if the company's entire service area stays fixed, an increase in the number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system.

James C. Bonbright, Principles of Public Utility Rates, Columbia University Press, 347-348 (1961).

This objection is reinforced by the fact that the methodology's stated purpose -- to allocate those embedded distribution system costs that are a direct function of the number of customers served by the distribution system -- is one that is difficult to realize in practice with any reasonable degree of faithfulness to the nominal principle behind the method. I find the report[73] prepared by Frederick Weston (The Regulatory Assistance Project), cited by NCSEA witness Barnes, to be most informative on this subject. Weston notes in his Executive Summary that "The distribution network is no longer the seemingly static

[73] F. Weston, et al., *Charges for Distribution Service: Issues in Rate Design*, Regulatory Assistance Project (2000), available at http://pubs.narus.org/pub/536F0210-2354-D714-51CF-037E9E00A724.

monopoly that it once was. The policies that regulators adopt should be devised with an eye to competitive service provision, to encourage innovative and environmentally sustainable energy use. They should not shortsightedly protect a status quo that, over the coming decades, will not be well-suited to the economy it serves."[74] Further, Weston states that "There is broad agreement in the literature that distribution investment is causally related to peak demand. Numbers of customers on the system and energy needs are also seen to drive costs, but there is less of a consensus on these points or on their implications for rate design. In addition, not all jurisdictions employ the same methods for analyzing the various cost components, and there is of course a wide range of views on their nature; marginal, embedded, fixed, variable, joint, common, etc. and thus on how they should be recovered in rates."[75]

The Company implicitly acknowledges this problem when it concedes that its actual application of the minimum system concept is a modification or variation of the pure principle. See Tr. Vol. 19, pp. 38-39. I do not agree with the majority's opinion that the minimum system analysis employed by the Company is not flawed in a way that makes it inappropriate for cost allocation in this proceeding. Rather, the critiques offered by NCSEA and NC Justice Center, et al., in their post-hearing briefs, and the testimony of witness Barnes, in particular, are compelling. In its post-hearing Brief, NCSEA states that "the minimum system analysis is flawed." See NCSEA's Post-Hearing Brief, p. 37. NCSEA states that the minimum system methodology "assumes that some costs of the shared distribution system are effectively incurred solely for the purpose of connecting each customer and that these costs should therefore be classified as customer-related." Tr. Vol. 20, pp. 75-76. In effect, the system methodology "double counts" demand-related costs because a minimum system is still capable of serving some level of demand. Id. at 76.

Furthermore, NCSEA states that the Company's modified minimum system methodology does not examine actual costs, but rather defines costs for specified components and extrapolates those costs across the Company's system. Id. at 86. In the case of poles and conductors, this results in more items being included in the minimum system study than are actually on the Company's system and results in a negative assignment of these components in the demand charge. Id. at 87. Further, NCSEA states that the Company's modified minimum system methodology contains flaws in its analysis of poles and structures, overhead conductors, line transformers, and service drops. Id. at 90-94.

According to witness Barnes, DEC effectively classifies all shared secondary and primary poles in FERC Account 364 (as well as conductors in FERC Account 365) as customer-related. This is visible in the Company's COSS in the form of negative values for demand-related plant in service for FERC Accounts 364 and 365.[76] The negative

[74] Id. at 5.

[75] Id. at 28.

[76] DEC Form E-1, Item 45D, p. 5.

values arise because the Company's calculated minimum system is larger than the actual FERC Account balance after removing direct assignments, which necessitates an adjustment. The true-up adjustment effectively results in a demand-related component of zero and a customer-related component of 100%. Similar differences are evident for other distribution Accounts, contributing to a wide range of estimates of residential customer unit costs. Tr. Vol. 20, pp. 82-83. These detailed objections to the Company's practical application of the method in practice are not effectively rebutted by the Company, and this in itself is some confirmation of a large degree of subjectivity in how the method is applied to a real world distribution system.

If the minimum system method is inappropriate for assignment of the customer portion of distribution system costs among the several customer classes, then what is to replace it? Here I suggest that a defensible method, and the one that is most widely used by other regulatory authorities, is perhaps to use a per customer allocator only for those costs directly attributable to the addition of another customer to the distribution grid – the cost of the customer meter, the service drop, and any other facilities uniquely attributable to a specific customer. All other distribution system costs, including poles, transformers, and conductors, would use a demand allocator entirely. This is the so-called "basic customer method" well-recognized and widely used as an alternative to fixed charges that are designed to reflect output from the minimum system method of cost allocation. The Commission's Order acknowledges this by recognizing the testimony of witness Barnes and specific reference to Mr. Weston's report, which states that "There are a number of methods for differentiating between the customer and demand components of embedded distribution plant. The most common method used is the basic customer method, which classifies all poles, wires, and transformers as demand-related and meters, meter-reading, and billing as customer-related. This general approach is used in more than thirty states."[77] Tr. Vol. 20, p. 79.

Shared distribution plant and facilities, whose cost would be assigned using a demand allocator, are those actually installed by the Company to meet real world expected demand and maintain service reliability. Put differently, excluding only the marginal costs directly attributable to the addition of another customer, the system whose costs must be recovered is not sized to meet some "phantom" level of demand but instead is sized to meet actual historical and projected system demand. It is the costs of this real world system that must be allocated, and those costs are heavily driven by demand.

Turning back to the topic of the fixed monthly charge, if the minimum system method is not used for distribution system cost allocation purposes, what, then, is? What, then, are the proper determinants of that component of the customer's bill? I believe we perhaps should answer that question in the same way the majority of other jurisdictions do: the monthly fixed charge should reflect the cost for the service drop, the meter, any other facilities uniquely deployed to connect a customer to the system, to

[77] F. Weston, et al., *Charges for Distribution Service: Issues in Rate Design*, p. 19, Regulatory Assistance Project (2000), available at http://pubs.narus.org/pub/536F0210-2354-D714-51CF-037E9E00A724.

which would be added an allocation of the administrative support costs of meter reading, billing, collections, and customer service.

Given the concerns and issues presented by use of the minimum system methodology, I think that the Company's fixed monthly charges for the several customer rate classes likely already equal or even exceed the level that would be arrived at using the "basic customer method" for cost allocation purposes and the principle of cost causation for purposes of rate design. For example, the current BFC for the residential rate schedule RS is $11.80, whereas the unit cost without minimum system is calculated to be $11.08. See Tr. Vol. 20, p. 77; Pirro Direct Testimony Exhibit 8.

I also note that once the distraction of the minimum system method is removed from consideration, other arguments used to support a higher monthly fixed charge take on a new aspect. As has been stated already, proponents of increasing the fixed charge rely largely on the results of the minimum system method and the principle of cost causation, but they supplement their positions by noting that a fixed monthly charge that is set at a level lower than the fully distributed per customer costs derived from using the minimum system also results in overcompensating for energy efficiency and distributed generation. It does this, they say, by artificially increasing the energy charge component of customer rates. However, once we conclude that the Company's current fixed monthly charge already fully compensates for properly allocated fixed customer costs, using the "basic customer method," then the issue of overcompensation or undercompensation for energy efficiency and distributed generation falls away. This is so because so long as the Company's fixed monthly residential customer charge fully covers the properly allocated customer portion of its costs, the remainder of the established rate will reflect only the demand and energy costs allocable to that customer class.

If, as I believe the evidence clearly shows, the Company's current fixed monthly charge for residential customers already covers its fixed costs were the basic customer method of cost allocation used, then certain other issues that occupy the majority's attention would also disappear. The majority expresses concern about internal subsidization within the residential rate classes when fixed costs are apportioned to the energy rate, thereby penalizing high usage customers and benefitting lower usage customers. But again, if the existing fixed monthly charge is already set at a level that compensates the Company for its fixed per-customer costs, using a method other than the deeply flawed minimum system, no such subsidization is occurring.

The one virtue of a high fixed charge component of bills is that it improves revenue stability for the Company; the higher the fixed component, the more stable revenues will be. While this is not an unimportant consideration, it does not outweigh the conceptual flaws and difficulties in execution involved in the minimum system method. There are other, and in my view better, methods for addressing the utility's need for stable revenues. I am optimistic that the Public Staff and utilities' pending work to further evaluate use of the minimum system method and alternative methods for allocating distribution will "bear fruit" and appropriately inform future decisions. In this regard, I concur with Mr. Weston's admonition in his report, to be practical. He further states that:

> [T]here is the designation of a cost as either customer or demand, which will affect both how costs are divvied up among classes and who within each class will pay them (i.e., both inter- and intra-class allocations). While there is a touch of cynicism in the observation that there is no shortage of academic arguments to justify particular outcomes, it is nevertheless largely true. Always be aware of the revenue effects of a particular rate structure. Who benefits, who loses? Fixed prices, because they recover revenues by customer rather than by usage, invariably shift a larger proportion of the system's costs to the lower-volume consumers (residential and small business). The positions that interested parties take with respect to rate design should, in part, be considered in light of their impacts on class revenue burdens and on the profitability of the utility. Here the admonition to be practical cannot be stressed enough.

F. Weston, et al., Charges for Distribution Service: Issues in Rate Design, p. 19, Regulatory Assistance Project (2000), available at http://pubs.narus.org/pub/536F0210-2354-D714-51CF-037E9E00A724.

Finally, I take note of the fact that the evidence before the Commission in this case concerning the Company's proposed Power Forward initiative and its associated request for a cost recovery rider provides additional grounds that would tend to support rejecting the minimum system method as a means for assigning distribution plant costs to the several customer classes. In response to a question posed at the hearing concerning the impact, if any, of the planned targeted undergrounding investments on the application and output of the Company's minimum system method, the Company offered the following explanation in a post-hearing submission. Currently, underground distribution facilities are not considered by the Company to be part of a "minimum system," since they are considered non-standard installations. As a result of the Company's proposed Targeted Undergrounding Program, this would change, and underground installations will then be considered components of a "minimum system." See DEC Late-Filed Exhibit Regarding Planned Change to Minimum System Methodology (April 6, 2018). Because, subject to variation and exceptions, underground plant is generally more costly than overhead facilities, this would result in a greater total distribution plant cost assigned to each of the customer classes than is presently the case. Further, because the residential rate class has by far the most numerous membership, most of this additional "minimum system" cost would very largely fall on that class. Not surprisingly, this will almost certainly mean that in future rate cases the Company will contend that its per customer cost of service, derived in part from application of the minimum system method, is even higher than it is today, thereby warranting a further increase in the fixed monthly per customer charge. Most likely, this same result will obtain with respect to some other elements of the Power Forward investments, such as the creation of distribution system redundancies that will be necessary to support a self-optimizing and self-correcting distribution system.

The theoretical objections to the minimum system methodology are even more apt in the case of the proposed Power Forward investments. Correlation between the need for underground plant and the number of customers on the system is vanishingly weak; as explained by the Company, the need for underground distribution plant is instead driven by the density, age, and condition of vegetation and by animal and bird populations along distribution lines. The purpose of undergrounding plant is to protect the distribution system from service interruptions, a demand-related concept, and is not dependent on the number of customers whose aggregate demand is at risk of interruption. I find it difficult to consider these investments to be part of a "minimum system." Certainly, they may improve the reliability and resilience of the distribution grid, but these are enhancements to a "minimum system," not elements of it. The point here is that what constitutes a "minimum system" for purpose of cost allocation among customer classes requires the exercise of judgment; it is not something that is self-evident. In my judgment, including the types of distribution plant upgrades that are contemplated by the Power Forward system in the "minimum system" strays too far from the theoretical justification that supports use of the minimum system methodology.

I recognize that the majority is not yet prepared to move to the basic method over the minimum system method in spite of the implications for the fixed monthly charge. Nonetheless, in light of the legitimate issues raised with respect to the minimum system method and the Commission's decision that these issues are sufficient to warrant greater in depth investigation, I believe the counsel of prudence would be to leave the current level of the fixed monthly charges in place pending that consideration, especially in light of the lack of any need for additional revenue. That is an outcome I could have supported; I do not support increasing the residential fixed monthly charge by $2.20 per month.

IV. Cost-Effectiveness and Prudence of Advanced Metering Infrastructure (AMI)

The majority approves DEC's request to recover its costs of replacing Advanced Meter Reading (AMR) meters with AMI, and DEC's recovery of the remaining book value of its AMR meters. The majority reasons that DEC's AMI costs are reasonable, and that DEC's decision to replace its AMR meters with AMI was prudent. I do not question the reasonableness of DEC's AMI costs. However, based on the evidence I conclude that DEC's deployment of AMI is not cost-effective and, largely as a result of that lack of cost-effectiveness, DEC's decision to deploy AMI was not prudent. Therefore, I would deny DEC's request to recover its AMI costs in this proceeding, but allow DEC to defer those costs, with no carrying charge, until a future general rate case in which DEC produces substantial evidence that AMI is cost-effective.

A. DEC's Failure to Comply with Rule R8-60.1

The Majority Order includes the details of the pertinent proceedings under Commission Rule R8-60.1, the rule on smart grid technology plans. In addition, the following segment from the Commission's March 29, 2017 Order Accepting Smart Grid Technology Plans (SGTP Order), in Docket No. E-100, Sub 147, is of note. After citing several requirements of Commission Rule R8-60.1 with respect to the information to be provided by the electric utilities for smart grid technologies currently being deployed or scheduled for implementation within the next five years, the Commission stated:

> [t]he Commission notes that neither DEC, DEP nor DNCP included the above information in their 2016 SGTPs with regard to any future plans for deployment of AMI meters. The Commission interprets this to mean that DEC, DEP and DNCP currently have no plans to replace existing meters with AMI meters, either incrementally or on full scale, during the next five years. As a result, the Commission expects DEC, DEP and DNCP to provide the Commission with the above information, as well as any other required information, in their SGTP filings prior to implementing an incremental or full scale effort to replace existing meters with AMI meters.

SGTP Order, p. 17.

Commission Rule R8-60.1(c)(3) requires the electric utilities to provide the Commission with a cost-benefit analysis and other detailed information about smart grid technologies currently being deployed by the utilities or scheduled for implementation within the next five years. One purpose of the rule is to allow the Commission, Public Staff and other interested parties to review information about proposed smart grid programs, request additional information when needed, and have input regarding the implementation of smart grid programs well in advance of their implementation. Smart grid technologies are relatively new and evolving projects that require substantial capital investments. Therefore, the public interest is best served by the Commission and parties having sufficient time to study and understand the details of a smart grid project before it is launched. DEC appears to support this purpose. In his rebuttal testimony, in response to EDF witness Alvarez's recommendation that the Commission review DEC's AMI project in a separate docket, witness Schneider testified:

> [T]he Commission already has a SGTP rule and dockets to review, allow for intervenor investigation and comment, and ultimately accept, modify or reject the Company's SGTP and those of other utilities.

Tr. Vol. 18, p. 342.

Notwithstanding DEC's understanding of and appreciation for the Commission's SGTP rule, as noted above DEC did not provide a cost-benefit analysis and other required information in its 2016 SGTP to support an AMI deployment. Consequently, the Commission directed DEC "[t]o provide the Commission with the above information, as well as any other required information, in their SGTP filings <u>prior to implementing an incremental or full scale effort</u> to replace existing meters with AMI meters." SGTP Order, at p. 17 [emphasis added] Nevertheless, DEC, as it stated in its May 5, 2017 supplemental filing, began deploying AMI meters "in early 2017." Thus, DEC began its deployment of AMI before complying with the requirement to file the cost-benefit analysis and other information required by Commission Rule R8-60.1, and in contradiction to the Commission's 2016 SGTP Order.

The Commission, by its SGTP Order issued on March 29, 2017, accepted DEC's 2016 SGTP as originally filed. In its May 5, 2017 supplemental filing, DEC stated that in late 2016 it decided to begin a full scale deployment of AMI in North Carolina, even though DEC had stated in its 2016 SGTP, filed on October 3, 2016, that it was studying whether to implement AMI. DEC's decision to begin a full scale AMI deployment "in late 2016" must have been made in November or December of 2016. Further, DEC stated in its supplemental filing that it began deploying AMI meters "in early 2017." Yet DEC waited until May 5, 2017, to inform the Commission of its decision to begin AMI deployment and its implementation of that decision. DEC's May 5, 2017 supplemental filing was a substantial amendment to its 2016 SGTP. DEC did not request that the Commission issue an order accepting its amended 2016 SGTP. More importantly, the Commission did not issue an order accepting DEC's amended 2016 SGTP.

Based on the foregoing, I conclude that DEC failed to comply with the letter and the spirit of Commission Rule R8-60.1. The result was that DEC defeated the ability of the Commission, Public Staff and other interested parties to provide advance input regarding the implementation of AMI. Instead, DEC made the decision to deploy AMI and began implementing that decision without informing the Commission and obtaining the Commission's acceptance of that significant revision to DEC's 2016 SGTP. To be clear, I do not base my denial of DEC's AMI cost recovery on its failure to comply with Rule R8-60.1. However, I do find it important in providing context to my analysis.

B. <u>Cost-Effectiveness of DEC's AMI</u>

In DEC's supplemental information filing on May 5, 2017, in the SGTP Docket, DEC stated that it would be replacing approximately 1.32 million AMR meters from 2017 through 2019. (Supplemental Filing, p. 2) In the AMI cost-benefit analysis filed by DEC as a part of its supplemental filing, DEC concluded that its AMI deployment would result in net benefits having a present value of $117.1 million. (Supplemental Filing, Exhibit No. 2) The largest category of benefits included in the analysis is entitled "Non-technical line loss reduction - power theft, equipment failures and installation errors" (NLLR). It is the last column of benefits shown on Exhibit No. 2, and totals $634.8 million. In comparison, the next largest category of benefits is "Reduced meter operations costs – consumer order workers for meter orders," a total of $175.4 million. According to the cost-benefit analysis, the total of the AMI benefits is $1.007 billion. Thus, the NLLR portion of the benefits is 63% of the total.

In response to question number 2 included in the Commission's SGTP Presentation Order, DEC stated, in pertinent part:

> According to a 2008 EPRI report, industry experts project that a reasonable percentage for non-technical losses is 2% of gross revenue. This assumption was utilized in calculating the DEC AMI benefits.

DEC's First Responses, p. 5.

During DEC's SGTP presentation, DEC witness Schneider was asked whether EPRI or any other entity performed a physical real world study to verify the 2% NLLR figure. Witness Schneider responded:

> Not to my knowledge. I think they went on data. Again, this was a report, not necessarily a study but it was a report, and they were going off of other reports and studies going back years and years that came up with this on average 2 percent of gross revenues so they did not.

SGTP Presentation, Tr., p. 40.

Witness Schneider also stated that DEC has not performed a study that confirms the 2% NLLR factor reported by EPRI. In addition, witness Schneider stated that based on DEC's cost-benefit analysis the costs of the AMI deployment would outweigh the benefits until 2025. SGTP Presentation, Tr. Vol. 18, p. 44.

In the Commission's Additional Information Order, the Commission requested that DEC provide the following information:

> 8. Using the actual historical kilowatt-hour and lost revenue data for energy theft that DEC has experienced and is discovering in North Carolina, including during its AMI deployment, develop an independent estimate of the percent of additional revenues DEC will collect via that deployment that would otherwise be lost due to theft and other non-technical losses.
>
> 9. Provide a revised 20-year AMI cost-benefit analysis that includes: (a) the costs of replacing AMI meters at the end of their 15-year lives, (b) the most recent estimate of the costs of cellular direct connect meters, (c) the cost of replacing other components and software at reasonable intervals, and (d) the non-technical revenue loss estimate (rather than the EPRI 2% estimate) developed pursuant to question 8.

DEC's revised AMI cost-benefit analysis was attached to DEC's Second Responses and filed in the SGTP Docket on December 15, 2017, as Exhibit No. 2. The largest category of benefits included in the analysis continues to be "Non-technical line loss reduction - power theft, equipment failures and installation errors." However, the amount of the NLLR benefit went down from $634.8 million to $448.8 million. In addition, the revised cost-benefit analysis, which includes the cost of replacing AMI meters at the end of their 15-year useful life, shows that AMI deployment would result in net costs having a present value of $49.9 million (DEC's Second Responses, Exhibit No. 2).

DEC witness Schneider takes issue with the Commission's requirement that DEC include in its revised cost-benefit analysis the costs of replacing AMI meters at the end of their 15-year lives. Witness Schneider stated that this adjustment was not a conventional part of DEC's usual business case assessment. He opined that it essentially doubled the cost of the replacement meters over a 30-year period, but only accounted for the benefits of the meters for 15 years, the life of the current AMI meters being deployed by DEC. Tr. Vol. 18, pp. 408-14.

I am not persuaded by witness Schneider that the cost of replacing AMI meters at the end of their 15-year useful life should not be included in the AMI cost-benefit analysis. Public Staff witness Maness testified that DEC's existing AMR meters have an average remaining useful life of 15.4 years, and that this is the period of time that should be used to calculate DEC's annual AMR depreciation expense. Tr. Vol. 22, pp. 103-04. Further, there is no contention or evidence that DEC's AMR meters are not functioning properly or are not serving their intended purpose. Nevertheless, DEC is requesting that ratepayers pay for discarding the AMR meters and replacing them with AMI. In addition, the AMI meters being deployed by DEC were manufactured in 2009. Tr. Vol. 18, pp. 374-75. Based on these facts, it is reasonably likely that in 15 years, or perhaps sooner depending on further developments in AMI technology, DEC could be before the Commission requesting to scrap its 2009 AMI meters and to replace them with the latest metering technology. As a result, it is appropriate to include in DEC's cost-benefit analysis the cost of replacing in 15 years the AMI meters presently being deployed by DEC.

I conclude that the first cost-benefit analysis produced by DEC was not properly structured, and, therefore, it was not reasonable for DEC to rely on that analysis in deciding to fully deploy AMI. The first analysis was not properly structured because, as noted above, it did not include the cost of replacing the AMI meters after 15 years. In addition, DEC's first cost-benefit analysis was not properly structured because DEC used the EPRI 2% NLLR factor.

In the December 2008 EPRI Report, EPRI noted the following reasons for non-technical losses:

- Non-performing and under-performing meters.
- Incorrect application of multiplying factors.
- Defects in current transformer and potential transformer circuitry.
- Non-reading of meters.
- Pilferage by manipulating or bypassing meters.
- Theft by direct tapping and so on.

2008 EPRI Report, pp. 1-3.

With regard to the measurement of non-technical losses, the EPRI Report stated:

> Non-technical losses, by definition, are losses that are not accounted for and are, therefore, not subject to analytical measurement. Non-technical losses are simply the difference between the energy delivered to the

> distribution system and billed to end-users, less technical losses. Although there is agreement on the importance of non-technical losses, there is no firm data to define the level of losses on an industrywide basis. However, the importance of non-technical losses, especially in terms of their impact on revenue, is such that distribution utilities try to quantify them.
>
> Such quantification is very difficult. Quantifying what statisticians call “unaccountable for” attempts the impossible. There is an inherent difficulty in obtaining data on unmetered supplies and theft. Estimating the revenue impact of non-technical losses presents yet further difficulties. This is brought into relief when trying to measure the benefits of AMI in reducing non-technical losses. Although there are expectations that AMI will help to reduce non-technical losses, the measurement of benefits (or costs) from AMI deployment are considered non-quantifiable.

2008 EPRI Report, p. 1-7 (emphasis added).

The above discussion about the difficulty of quantifying NLLR is not convincing, particularly with regard to DEC. I accept the statement in the EPRI Report that “there is no firm data to define the level of losses on an industrywide basis.” However, DEC had no reason to measure NLLR on an industrywide basis. DEC has been providing electric service in North Carolina for over 100 years. Consequently, DEC has a wealth of experience and knowledge about the components that make up NLLR, such as non-performing and under-performing meters, and theft losses. Therefore, it was unnecessary and unreasonable for DEC to use EPRI's 2% NLLR factor rather than DEC’s actual NLLR amount. As a result, with respect to determining the cost-effectiveness of DEC’s AMI deployment, I give no weight to DEC's first cost-benefit analysis.

Instead, I give substantial weight to the revised cost-benefit analysis provided by DEC on December 15, 2017. The revised cost-benefit analysis, using DEC’s actual NLLR numbers, is a reasonable and accurate methodology for projecting the costs and benefits of AMI, and, therefore, is probative evidence of such costs and benefits.

The majority gives substantial weight to DEC’s evidence of future energy saving and peak shaving rate designs that can be supported by AMI. In DEC's Supplemental Filing, DEC discussed the possibility of additional customer services to be provided by AMI.

> [A]MI is the foundational investment that will enable enhanced customer solutions – giving customers greater control, convenience and choice over their energy usage, while also giving customers the opportunity to budget, save time and money. AMI technology allows a utility to gather more granular usage data and utilize new capabilities to offer new programs and services to customers that are not achievable through existing meters. The AMI technology will pave the way for programs that will allow customers to stay better informed during outages, control their due dates, avoid deposits, to be reconnected faster, and to better understand and take control of their energy

> usage, and ultimately, their bills. Over time, the Company also expects AMI meters to contribute to cost reductions from reduced truck rolls in the years after deployments.

Supplemental Filing, p. 1.

In the Commission's SGTP Presentation Order, with regard to the above statement, question number 7 asked DEC to "Explain fully whether and how all of the costs for developing and deploying those services are included in the cost-benefit analysis." In response, DEC stated:

> No costs or benefits for developing and deploying additional customer programs/services were included in the AMI cost –benefit analysis.

DEC's First Responses, p. 8.

Nevertheless, during cross-examination by DEC's counsel witness Schneider stated:

> [t]here is a lot of additional customer programs and benefits that the AMI, as a foundation, enables that, again, we didn't have those costs and benefits in our cost-benefit model because they just weren't designed yet. We didn't know what the costs were in each of those cases, you know, will be on their own. So in general, with a positive business case, and plus the fact that we know there is additional customer products and services that this solution can enable, the Company has made a decision that this is a viable project that we want to move forward with.

Tr. Vol. 18, pp. 413-14.

I give no weight to witness Schneider's testimony regarding possible new rate designs, additional customer programs and additional customer benefits not identified and not included in the cost-benefit analysis. DEC has the proverbial cart before the horse. Future possible rate designs and other measures that may be developed and that may provide customer benefits are much too speculative for the Commission to accept as probative evidence.

Public utilities are required to provide cost effective services. G.S. 62-2. DEC's revised AMI cost-benefit analysis shows that on a present value basis the cost of DEC's AMI deployment is $49.9 million more than the benefits. In addition, another major cost of DEC's AMI deployment is the lost value of DEC's AMR meters, which will be approximately $85 million.[78] The AMR meters still have 15 years of useful life and are serving their

[78] DEC's 2017 SGTP Update stated that the remaining net book value of its AMR meters was an estimated $127.66 million as of March 31, 2017. However, in the SGTP presentation witness Schneider

intended purpose. Nevertheless, DEC would discard the AMR meters and recover the loss of the approximately $85 million book value from DEC's ratepayers.

Moreover, DEC proposes to include in its new rates the recovery of AMI costs and the recovery of AMR stranded costs. The result would be that DEC's customers would be paying for AMI and AMR meters for the next 15 years. Yet, even under DEC's initial cost-benefit analysis, ratepayers would not see the net benefits of AMI until 2025. Thus, there would be a period of seven years in which DEC's ratepayers would be paying for AMI meters without receiving net benefits from those meters, and paying for AMR meters that have been scrapped by DEC. Based on the present value of the cost of DEC's AMI deployment being $49.9 million more than the benefits, the loss of 15 years of useful life of DEC's existing AMR meters, and the double meter costs that ratepayers would be required to pay for several years, I conclude that a preponderance of the evidence shows that DEC's AMI deployment is not a cost-effective method of providing service.

C. Prudence of DEC's AMI Implementation

In Docket No. E-2, Sub 537, the Commission addressed alleged imprudence by Carolina Power & Light (CP&L), DEP's predecessor, in the construction of the Shearon Harris Nuclear Plant. The Commission disallowed certain costs of construction based on its findings of imprudence by CP&L that resulted in unreasonable delays and avoidable errors in the construction of CP&L's Harris plant. 78 North Carolina Utilities Commission Orders and Decisions 238 (August 5, 1988) (Harris Order); reversed in part, and remanded (on other grounds), State ex rel. Utilities Comm'n v. Thornburg, 325 N.C. 484, 385 S.E.2d 463 (1989). The Commission stated the general standard of prudence as

> [w]hether management decisions were made in a reasonable manner and at an appropriate time on the basis of what was reasonably known or reasonably should have been known at that time (citation omitted)…The Commission notes that this standard is one of reasonableness that must be based on a contemporaneous view of the action or decision under question. Perfection is not required. Hindsight analysis – the judging of events based on subsequent developments – is not permitted.

Harris Order, at 251-252.

As previously discussed, DEC's first cost-benefit analysis was not properly structured because it included DEC's use of the EPRI 2% NLLR factor. It was unnecessary and unreasonable for DEC to use EPRI's 2% NLLR factor rather than DEC's actual NLLR experience. With respect to determining the prudence of DEC's AMI deployment, I give substantial weight to DEC's use of its first cost-benefit analysis in

testified that DEC would receive tax benefits that would reduce the lost book value to approximately $85 million. (SGTP Presentation, Tr., pp. 42-43.)

making the decision to deploy AMI. It was not reasonable for DEC to rely upon that analysis in deciding to fully deploy AMI and, therefore, DEC's decision to deploy AMI was not a prudent decision.

In addition, I give substantial weight to the testimony of Public Staff witness Maness that DEC's existing AMR meters have an average remaining useful life of 15.4 years, and that 15 years should be the length of time for recovering the AMR depreciation expense. The evidence in the present case does not support DEC's decision to discard AMR meters that are properly functioning and have 15 years of useful life, particularly when it leads to the unjust result that DEC's ratepayers pay the remaining $85 million book value of the AMR meters. DEC had all of this information in late 2016 when it made its decision to fully deploy AMI. In fact, DEC's 2017 SGTP Update stated that the remaining net book value of its AMR meters was an estimated $127.66 million as of March 31, 2017. Thus, when DEC began deploying AMI meters in early 2017 DEC knew that its decision meant that ratepayers would be required to pay somewhere between $127 million and $85 million for discarded AMR meters. Based on these facts, it was not reasonable for DEC to decide in early 2017 to fully deploy AMI meters and to discard its AMR meters. Therefore, DEC's decision to deploy AMI was not a prudent decision.

Finally, as previously discussed, DEC proposes to include in its new rates the recovery of AMI costs and the recovery of AMR stranded costs, which would result in DEC's customers paying for AMI and AMR meters for the next 15 years, even though under DEC's initial cost-benefit analysis ratepayers would not see the net benefits of AMI until 2025. Thus, there would be a period of seven years in which DEC's ratepayers would be paying for AMI meters without receiving net benefits from those meters, and paying for AMR meters that have been discarded by DEC. DEC had these facts when it decided to begin deploying AMI meters in early 2017. Based on these facts, at the time of the Company's decision in early 2017, it was not reasonable nor prudent for to deploy AMI meters and to discard its AMR meters.

Applying the <u>Harris Order</u> standard of prudence to the above facts, I conclude that a preponderance of the evidence shows that DEC's AMI deployment was not a prudent action when DEC began deploying AMI meters in early 2017. Therefore, I would deny DEC's request to recover its AMI costs, but authorize DEC to place its present AMI costs of $90.9 million and its future AMI costs in a deferred account, with no carrying charge, and to seek recovery of those costs in a future general rate case. In addition, I would require that DEC continue depreciating its AMR meters as presently scheduled, and remove AMR meters from rate base as they are replaced.

V. CONCLUSION

My conclusions in summary are these:

(a) that the Majority Order imposes on ratepayers a substantial amount of costs directly attributable to the Company's imprudent management of its waste coal ash impoundments at the Dan River plant, imprudence that produced the release of waste ash into the Dan River in February, 2014;

(b) that the Majority Order improperly shifts to present and future customers a substantial amount of costs for closure of the Company's waste coal ash impoundments that should have been charged and collected from prior customers for electricity service provided in the past;

(c) that the Majority Order, without proper analysis or foundation in law or in record evidence, impermissibly authorizes the Company to earn a return, or profit, from the deferred amounts expended by the Company in the period 2015 through 2017 for costs related to the closure of its waste coal ash impoundments;

(d) that the Majority Order, again without basis in the record and in a manner that unfairly discriminates among different classes of customers, permits the Company to increase the fixed monthly charge to its residential customers, even though the majority decision finds that the Company does not require any increase in revenue from residential customers or from any other class of customers; and

(e) that the Majority Order improperly permits the Company to include in its rates the costs of replacing existing customer meters with new advanced technology meters, even though the existing meters have not reached the end of their useful lives and the Company is not presently able to offer to customers any material benefits from the new advanced technology meters.

For these reasons, I cannot conclude that the rates that will follow from the Majority Order are just and reasonable as required by law. I therefore dissent. In addition, I join in the dissenting opinion filed in this matter by Commissioner ToNola D. Brown-Bland.

/s/ Daniel G. Clodfelter
Commissioner Daniel G. Clodfelter

DOCKET NO. E-7, SUB 1146
DOCKET NO. E-7, SUB 819
DOCKET NO. E-7, SUB 1152
DOCKET NO. E-7, SUB 1110

Commissioner ToNola D. Brown-Bland, concurring in part and dissenting in part:

I respectfully dissent in part from the majority opinion and join in the dissenting opinion of Commissioner Clodfelter with respect to the decision to allow an increase in the fixed monthly residential charge; the approval of cost recovery in this general rate case for both the deployment of Advanced Metering Infrastructure (AMI) meters and the depreciation of Advanced Meter Reading (AMR) meters being replaced by AMI deployment 15 years before the end of their useful life; and the approval of waste coal ash cost recovery such that the Company ultimately will be permitted the opportunity to recover over 97% of its total projected waste coal ash removal costs of $2.6 billion from the ratepayers of North Carolina, despite substantial evidence of the Company's imprudent choices and actions leading to the incurrence of certain specific and identifiable costs. It is my opinion that each of these decisions is contrary to the Commission's charge to make rates that are just and reasonable. See G.S. 62-2 and 62-130.

A. Fixed Monthly Residential Charge

I join in Commissioner Clodfelter's dissenting opinion to the extent he finds that the majority decision to increase the residential fixed charge from $11.80 to $14 is not supported by any evidence of record, let alone substantial evidence as is required for all Commission decisions pursuant to G.S. 62-65, and to the extent of the shortcomings and criticisms he finds regarding the majority's "subsidization" and "cost causation" rationales for increasing the fixed residential charge by $2.20 per month. I further point out that while the increase to $14.00 appears to be arbitrary, it just happens to be the same as the fixed residential customer charge adopted in the Commission's Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase, Docket No. E-2, Sub 1142, on February 23, 2018. (DEP Order).[79] In the DEP Order, $14.00 was the agreed upon amount accepted and settled upon in the Stipulation between the Public Staff and DEP. Given the cost evidence of record in the DEP case and the give-and-take of settlement negotiations leading to the Stipulation between the Public Staff and DEP, combined with the continued use and acceptance of the minimum system cost allocation method at the time of the Commission's decision, I found the

[79]Choosing the monthly fixed cost charge for DEC based on the charge the parties stipulated to in DEP would not be in keeping with the requirement to set just and reasonable rates based on substantial evidence. As DEC witness Pirro testified, "Other utilities" cost and rates are not relevant to a determination of DEC's rates." He explained that rates should be set based on examining a utility's own cost of service. Tr. Vol.19, p. 84.

Commission's acceptance of the stipulated $14.00 charge for the fixed cost portion of the residential rates reasonable for DEP and its customers.

In contrast, in the present DEC rate case, there is no settlement or stipulation of the Company's request to increase the monthly fixed charge, there is no substantial support in the record suggesting that the fixed cost attributable to the residential class has increased over what was supported and found reasonable when the Commission set the Company's current rates, and thus no substantial evidence that an increase in the fixed cost portion of the residential rate is appropriate at this time. Moreover, the Company's overall revenue requirement is being decreased in the present general rate case, suggesting that any alleged subsidy effect cited by the majority is already minimized to a degree by the lesser revenue requirement, alleviating the perceived need to increase the residential fixed charge in haste.

Additionally, while the majority states a concern about minimizing subsidization, its focus is unfairly and discriminatorily upon only the residential class of customers. The Company requested that the Commission increase the monthly fixed charge for all classes of customers including the non-residential classes. That the Company sought to increase non-residential fixed charges based on DEC's cost of service indicates the Company's position and belief that its current non-residential rates are not properly balanced between fixed charges and demand charges, and that it believes that interclass subsidization exists within the non-residential classes similarly to the subsidization it believes is present in the current rates for the residential class. The majority opinion brushes off this concern even though the Company was obviously aware that its subsidization and cost causation concerns should not apply to one class to the exclusion of others. Finally, while the majority has set the residential fixed charge at the same mark as it did in the DEP Order, DEC and DEP sought different levels of fixed cost charges for each of the two companies, recognizing them to have different cost structures. It is inexplicable that the majority would cause DEC ratepayers to pay the same fixed cost charge as DEP, when the evidence produced by the utilities in their respective cases tends to show that DEP's cost of service is higher than DEC's—an indication that the majority's decision is not based on actual costs.

With respect to the $14.00 fixed monthly residential charge sanctioned for DEC and its ratepayers, the majority opinion relies heavily on the concept that this charge strikes a proper balance and better reflects actual cost causation. However, no party presented evidence supporting $14.00 as the actual fixed residential cost of service. The majority claims to have chosen a cost number from within a range suggested by two different models for determining cost causation, but the evidence shows that the cost is either at the higher minimum system cost of $23.78 or at the lower basic customer cost method of $11.08. Choosing a random number between the two ends offered as evidence without a rational basis does not meet the Commission's obligation to set just and reasonable rates based on substantial evidence. <u>See</u> G.S. 62-65 and 62-131.

In addition, due to the flaws with and the need to review the use of the minimum system methodology which impacts the Company's rate design with respect to customer fixed cost charges (particularly in light of the likelihood that costly additions the Company plans to make to move its power system forward could have the effect of further increasing the fixed cost portion of the rates), I join in Commissioner Clodfelter's call first to have the benefit of access to the Commission-ordered evaluation of options for distribution system cost allocation and a study of consistent application of methodology prior to making any increase in the fixed monthly charge to residential ratepayers. As long as there is the reasonable possibility that after the Commission-ordered evaluation, the fixed distribution costs attributable to residential customer will be less than $14.00, it is unfair and unnecessary to increase this charge at this time given that in this general rate case the Commission has determined that the Company has no need for any additional revenue requirement. At this point in time, the increase in the fixed residential charge would appear to have more to do with stabilizing company revenues than with following cost causation principles or easing the burden of within-class subsidization through demand charges.

Accordingly, I find that the majority's increase of the monthly fixed residential charge is unjust and not reasonable based on the record before the Commission.

B. Recovery of Meter Costs

I join in Commissioner Clodfelter's dissent agreeing with him that DEC should not be allowed to recover AMI costs in this rate case but should instead be allowed to defer such costs until its next general case in which it could recover the deferred costs on producing substantial evidence that the Company's deployment of AMI meters is cost effective. I write to add that with the provisions that require the Company to move promptly to bring customers benefits from placing AMI meters in service such that ratepayers' likelihood of receiving value from paying for this new technology well before 2025, and before possible obsolescence of the new meters, is greatly increased, I would approve the Company's request to recover its AMI costs in this rate case, but for the majority's decision requiring ratepayers to continue paying for "new" and currently used and useful AMR meters at the same time they are to pay for new AMI meters. If the ratepayers were not required to pay for the AMR meters which still have a useful life of 15 years, I would find the decision to deploy AMI meters at this time prudent and cost effective.

It is patently unfair, unjust and unreasonable that the Company be allowed to make a unilateral decision stranding its own assets and then have the ratepayers pay for a decision within DEC's own control not only to strand its assets but also to strand them at a time when nearly $128 million in undepreciated value (reduced to $85 million by tax benefits) remained on the books. The majority's decision in essence means that ratepayers will be paying for two "shiny objects" at one time while they are able to use only one. There are certainly instances where allowing for recovery of stranded assets which represented a reasonable and prudent spend at the time of construction or deployment is the right decision, but when the utility's assets are stranded by its decision, made unilaterally on its own, and the assets are stranded with substantial useful life and functionality remaining, this is not one of those instances. I would protect the ratepayers from this situation and impose at least some of the cost for this decision to strand assets on the Company. There is no compelling evidence in the record that suggests that deploying AMI now and creating a stranded asset with many years of remaining useful life is necessary to the continued provision of safe, reliable, affordable and good quality service. It is unfair that ratepayers must continue paying for AMR for the next 15 years and not receiving benefit from those meters during a significant portion of that time period and also not receiving much additional benefit from the new replacement meters until some indefinite time in the future.

C. Recovery of coal ash basin closure costs

I join in the dissenting opinion of Commissioner Clodfelter and would allow recovery of some coal ash basin closure costs and deny others as he has well-detailed. I write to add that it is an unfair result that the majority's decision paves the way toward the ratepayers being responsible to pay over 97% of the Company's projected total waste coal ash removal costs of $2.6 billion in light of imprudent choices and actions by the Company that resulted in the incurrence of a significant portion of the costs now sought from the ratepayers.

Being imprudent or taking an action that is imprudent is not unlawful. On the other hand, committing an act that is unlawful, whether in violation of a criminal law, a regulation or a civil duty, is imprudent. Being imprudent with respect to an action or choice means being practically unwise, not careful, not cautious, or not circumspect. See Black's Law Dictionary, "Prudent," p. 1226 (West Publishing Co., 1990) (definition in pertinent part). The concept of imprudence is so basic and well-understood that we "know it when we see it" and analytic gymnastics is not required in order to recognize it. The same is true of imprudently incurred costs—these are costs that could have been avoided if the actor (in this case a utility), had made more cautious, wiser, or more careful decisions. A choice made could be a viable option, but still not have been a wise, prudent choice among viable approaches.[80]

Based on the entire record before the Commission, the record is replete with evidence of the Company's imprudent choices and acts of both commission and omission. Just a few examples in addition to those discussed in detail in Commissioner Clodfelter's dissenting opinion are the failure to take action to

[80] Under the North Carolina Public Utilities Act, imprudence on the part of a utility can be found without a showing or establishing of legal violation or breach of civil duty, but if either of those is established, such as by an admission of criminal negligence or by evidence in the record sufficient for a prima facie showing of civil negligence or of negligence *per se,* as I discussed in my dissent in Docket No. E-2, Sub 1142, Commission Order dated February 23, 2018, then a finding and conclusion of imprudence is proper and arguably required.

mitigate or eliminate groundwater contamination at Dan River at least as early as 2007, when based on its own knowledge as expressed in its own document entitled Environmental Management Program for Coal Combustion (Kerin AGO Cross Ex. 3), it should have realized the imprudence of a "minimum compliance with law" stance as opposed to taking actions it knew would have better protected surface and groundwater from contamination; the failure to heed the advice of its program engineers to provide a budget for camera inspection of stormwater pipes running under or through ash basins at the Dan River plant (Kerin AGO Cross Ex. 6); and the failure to follow its own closure plans to promptly begin dewatering the impoundments at Dan River following retirement of the coal units in 2012. Each of these actions or non-actions involved imprudent unwise decisions or choices and each led to specific identifiable costs that are included among the costs the Company and the majority would have the ratepayers pay nearly in their entirety.

Despite a record full of such examples of imprudence, the majority finds no imprudence and, therefore, fails to engage in the exercise of determining waste coal ash removal costs directly (much less indirectly) attributable to instances of imprudence on the Company's part. Not only does the record reveal imprudence in handling, storing, maintaining and monitoring waste coal ash just as it did in the DEP Rate Case, but as Commissioner Clodfelter explains, imprudent administrative and management decisions, such as not seeking recovery for basin closure costs in earlier rate cases, are also established by the evidence of record. Such decisions have led to some of the increased coal ash related costs being sought in this case from ratepayers far removed from the generation of ratepayers who received the benefit of electric service leading to the ash residue which is the subject of the costs sought by the Company today.

While, for many reasons, it is difficult and in some cases impossible to determine from the record all the costs attributable to the Company's imprudence, chasing perfection should not be allowed to become the enemy of the good. There is evidence in the record that permits identification and disallowance of specific discrete costs and/or cost increases caused by identifiable and known acts of imprudence. It is the better course of action, through disallowance of these costs, to have the ratepayers, who benefitted from affordable electricity service fueled by coal, and the Company and its shareholders reasonably share in the costs of waste coal ash removal and basin closure than to avoid the exercise of parsing through costs to distinguish between those that were prudently incurred and those that were not. An arbitrary monetary amount without rational basis chosen as a one-time management penalty cannot substitute for the Commission's duty to make rates that are fair to both the Company and its ratepayers on a case by case (incurrence by incurrence) basis considering all evidence of record in each individual case.

/s/ ToNola D. Brown-Bland
Commissioner ToNola D. Brown-Bland

SOAH DOCKET NO. 473-15-1556
PUC DOCKET NO. 43695

APPLICATION OF SOUTHWESTERN PUBLIC SERVICE COMPANY FOR AUTHORITY TO CHANGE RATES	**§ § §**	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

TABLE OF CONTENTS

LIST OF ACRONYMS AND OTHER DEFINED TERMS

A&G	Administrative and General O&M
ADIT	Accumulated Deferred Federal Income Taxes
AED-4CP	Average and Excess Demand – 4 Coincident Peak
AIP	Annual Incentive Plan
ALJ	Administrative Law Judge
Application	Application Filed in this Docket by SPS on December 8, 2014
ARC	Amarillo Recycling Company, Inc.
AXM	Alliance of Xcel Municipalities
BPU	Base Plan Upgrade
CAGR	Compound Annual Growth Rates
CAPM	Capital Asset Pricing Model
CCOSS	Class Cost-of-Service Study
CE	Comparable Earnings
CenterPoint	CenterPoint Energy Houston Electric, LLC
C&I	Commercial and Industrial
Cleco	Cleco Corporation
Commission	Public Utility Commission of Texas
CP	Coincident peak
CWIP	Construction Work in Progress
DCF	Discounted Cash Flow
Depreciation Study	Comprehensive Book Depreciation Accrual Rate Study at June 30, 2014
Dismantling Cost Study	Production Dismantling Cost Study
DOE	Department of Energy
EBITDA	Earnings Before Interest, Taxes, Depreciation, and Amortization
EECRF	Energy Efficiency Cost Recovery Factor
EPE	El Paso Electric Company
ESA	Electric Service Agreement
ETI	Entergy Texas, Inc.
FAS	Statement of Financial Accounting Standard
FERC	Federal Energy Regulatory Commission
Fitch Ratings	Fitch Ratings
FF	Finding of Fact
GAAP	Generally Accepted Accounting Principles
GDP	Gross Domestic Product
G&I	General and Intangible
Golden Spread	Golden Spread Electric Cooperative, Inc.
Hawaiian Electric	Hawaiian Electric Industries, Inc.
ICO	Interruptible Credit Option
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-Hour

LCRA	Lower Colorado River Authority
LGS-T	Large General Service – Transmission
LLF	Low Load Factor
LPL	Lubbock Power & Light
MAC	Management Applications Consulting, Inc.
MFF	Municipal Franchise Fee
Moody's	Moody's Investors Service
MW	Megawatt
MWh	Megawatt-Hour
NARUC	National Association of Regulatory Utility Commissioners
NCP	Non-Coincident Peak
New Mexico Commission	New Mexico Public Regulation Commission
NOAA	National Oceanic and Atmospheric Administration
NSPM	Northern States Power Company, a Minnesota corporation
Nuclear Decommissioning Guidelines	Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates
O&M	Operations and Maintenance
OATT	Open Access Transmission Tariff
Oncor	Oncor Electric Delivery Company
OPEB	Other Post-Employment Benefit
Operating Companies	Collectively, NSPM, Northern States Power Company, a Wisconsin corporation, PSCo, and SPS
OPL	Occidental Permian Ltd.
OPUC	Office of Public Utility Counsel
PFD	Proposal for Decision
PGS	Primary General Service
Pioneer	Pioneer Natural Resources USA, Inc.
PSCo	Public Service Company of Colorado, a Colorado corporation
PTD-PIS	Production, Transmission, and Distribution Plant-in-Service
PTYA	Post-Test Year Adjustment
PUHCA	Public Utility Holding Company Act of 1935
PURA	Public Utility Regulatory Act
REC	Renewable Energy Credit
RFP	Rate Filing Package
RR	Revenue Requirement Phase
RRR	Revenue Requirement and Rates (an SPP file)
RTL	Radial Transmission Line
S&P	Standard and Poor's
SAS	Service Agreement Summary
SEC	Securities and Exchange Commission
SGS	Small General Service
Sharyland	Sharyland Utilities, L.P.
SIP	Wholesale Energy Marketing and Trading Supplemental Incentive Program
SOAH	State Office of Administrative Hearings

Spot On	Spot On Award Recognition Program
SPP	Southwest Power Pool
SPS	Southwestern Public Service Company, a New Mexico Corporation
Staff	Commission Staff
State Agencies	State of Texas Agencies and Institutions of Higher Education
SWEPCO	Southwestern Electric Power Company
TAC	Texas Administrative Code
TCRF	Transmission Cost Recovery Factor
TDU	Transmission and Distribution Utility
Test Year	July 1, 2013, to June 30, 2014
TIEC	Texas Industrial Energy Consumers
TLG	TLG Services, Inc.
TOU	Time of Use
Towers Watson Study	2014 Towers Watson Compensation Study
TUCO	TUCO, Inc.
Value Line	Value Line Investment Survey
WACC	Weighted Average Cost of Capital
Wal-Mart	Wal-Mart Stores Texas, LLC and Sam's East, Inc.
Xcel Energy	Xcel Energy Inc.
XES	Xcel Energy Services Inc.

SOAH DOCKET NO. 473-15-1556
PUC DOCKET NO. 43695

APPLICATION OF SOUTHWESTERN PUBLIC SERVICE COMPANY FOR AUTHORITY TO CHANGE RATES	**§ § §**	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

PROPOSAL FOR DECISION

I. INTRODUCTION

On December 8, 2014, Southwestern Public Service Company (SPS) filed with the Public Utility Commission of Texas (Commission) an application for authority to change rates (Application). SPS is a fully-regulated investor-owned electric utility that serves retail electric customers in Texas and New Mexico and also serves wholesale electric customers. Its service area is in the Southwest Power Pool (SPP) region. SPS is a wholly-owned subsidiary of Xcel Energy Inc. (Xcel Energy).[1]

The Application uses a 12-month test year that runs from July 1, 2013, to June 30, 2014 (Test Year). In the Application as revised by SPS's rebuttal case, SPS seeks a base rate revenue increase of $42,074,996. The Commission's staff (Staff) and a number of Intervenors propose that SPS receive a base rate revenue decrease. For reasons discussed in this Proposal for Decision (PFD), the Administrative Law Judges (ALJs) recommend a base rate revenue increase of $1,243,949. Schedules reflecting the ALJs' recommendations are appended as Attachments A to D.

As agreed by SPS, the statutory deadline for the Commission's final order in this case is December 4, 2015.

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[1] Xcel Energy is a holding company under Federal Energy Regulatory Commission (FERC) regulations adopted under the Public Utility Holding Company Act of 2005. Xcel Energy is the parent company of four wholly-owned electric utility operating companies (Operating Companies): SPS; Northern States Power Company, a Minnesota corporation (NSPM); Northern States Power Company, a Wisconsin corporation; and Public Service Company of Colorado (PSCo). Xcel Energy is also the parent company of a non-profit service company, Xcel Energy Services Inc. (XES), and of two transmission-only entities regulated by FERC.

II. EXECUTIVE SUMMARY

This case is unusual in several respects that affected the evidence and arguments relating to the contested issues:

- For many years, SPS's Texas retail rates have been set pursuant to settlements. One party reported that SPS has not had a litigated base rate case in 27 years.[2]

- SPS proposed post-test year adjustments (PTYAs) for numerous rate base items. Its PTYAs included: (1) costs closed to book after the Application was filed; and (2) plant placed in service after the Application was filed. In its direct and rebuttal cases, SPS essentially proposed two alternative revenue requirements: one if the PTYAs were accepted, and one if they were rejected.

- To reflect PTYA-related data not available when the Application was filed, as well as to correct minor errors and incorporate other parties' adjustments to which SPS agreed, SPS's rebuttal case included substantially revised calculations and updated positions on various issues. In its rebuttal case, SPS's requested base rate revenue increase (which again assumed acceptance of the rate base PTYAs) was more than a third lower when compared to the Application, dropping from $64,746,197 to $42,074,996.

- Until this case, SPS has allocated costs among customer classes using an internally developed Excel model. Here, SPS used a new cost allocation method that allocates costs at the FERC account level, using software developed by Management Applications Consulting, Inc. Among other things, SPS's class cost-of-service study using the new methodology showed an approximate 20% increase in the share of SPS's investment costs assigned to Large General Service–Transmission customers compared to SPS's most recent rate case.

For reasons described above, SPS's Application, as revised by its rebuttal case—not its Application—is the starting point for the PFD's discussion of the issues in dispute. Unless stated otherwise, references to SPS's proposals refer to its proposals as revised in its rebuttal case. Some of the witnesses and other parties also updated their positions and calculations, and unless stated otherwise, references to their positions and calculations are to those last stated by the party or witness.

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[2] TIEC initial brief (Revenue Requirement (RR)) at 7.

The revenue requirement proposed in the PFD is based on the ALJs' recommendation to reject the rate base PTYAs. Staff developed its own class cost-of-service study, which was used for the number runs necessary to reflect the ALJs' recommendations in this PFD.[3]

Unless stated otherwise, the PFD discusses only issues that were contested based on the parties' ultimate positions.[4] All issues in this case, however, are included in the PFD's findings of fact, conclusions of law, and proposed ordering paragraphs. The ALJs recommend and intend that all flow-through impacts of their decisions on other issues be incorporated in the numbers reflecting their recommendations. The PFD does not separately discuss flow-through impacts unless the approach to flow-through impacts is itself a disputed issue or the ALJs believe further explanation would be helpful.

On the issues in this case, except where the PFD states otherwise, the ALJs find that SPS met its burden of proof as to its proposals (as revised in its rebuttal case). The ALJs' recommendations on the most major contested issues in this case are summarized below:

- accept SPS's proposed adjustments to jurisdictional allocation factors to reflect the loss of the Golden Spread Electric Cooperative, Inc. (Golden Spread) wholesale load;
- reject SPS's proposed post-test year adjustments to rate base;
- accept SPS's proposals regarding a prepaid pension asset;
- approve a 7.99% rate of return, which includes a 9.70% return on equity;
- approve a negative 2% net salvage value for SPS's Production Plant;
- use SPS's test year amounts for Schedule 11 expenses and revenues;

3 This was done under the usual procedures that avoid *ex parte* communications and preserve the confidentiality of the ALJs' decisions until the PFD is issued.

4 Thus, for example, if (1) another party proposed an adjustment to SPS's direct case, (2) in its rebuttal case SPS agreed to and made the adjustment, and (3) no one challenged SPS's rebuttal testimony making the adjustment, then the ALJs do not separately discuss the issue in this PFD but recommend that the adjustment be made.

- reject the United States Department of Energy's (DOE) proposed adjustments to operation and maintenance (O&M) expenses;
- accept SPS's cost of service study with minor adjustments;
- accept SPS's gradualism proposal to moderate rate-change impacts on individual customer classes; and
- accept SPS's proposed rate design with minor adjustments.

III. JURISDICTION AND NOTICE

SPS is an electric utility, a public utility, and a utility.[5] The Commission has jurisdiction over this matter.[6] The State Office of Administrative Hearings (SOAH) has jurisdiction over all matters relating to the conduct of the hearing in this case, including the preparation of this PFD.[7] SPS provided notice of its Application in accordance with PURA § 36.103 and 16 TAC §§ 22.51(a) and 25.235(b).

IV. PROCEDURAL HISTORY

SPS filed the Application on December 8, 2014. On December 9, 2014, the Commission referred this case to SOAH. On January 16, 2015, the Commission issued its Preliminary Order, including a non-exhaustive list of issues to be addressed in this proceeding.[8] On March 9, 2015, the ALJs issued an order severing into a separate new docket issues involving rate case expenses incurred in connection with this case.[9]

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[5] Public Utility Regulatory Act (PURA), Tex. Util. Code §§ 11.004(1), 31.002(6).

[6] PURA §§ 14.001, 36.001-36.111, 36.203-36.205, 36.209, and 36.210; 16 Tex. Admin. Code (TAC) §§ 25.231, 25.238, 25.239, 25.243, and 25.245. The Commission regulates SPS's Texas retail operations; the New Mexico Public Regulation Commission (New Mexico Commission) regulates SPS's New Mexico retail operations; and FERC regulates SPS's wholesale power sales and transmission of electricity in interstate commerce.

[7] PURA § 14.053; Tex. Gov't Code § 2003.049(b).

[8] Preliminary Order at 9 (Jan. 16, 2015).

[9] SOAH Order No. 6 (Mar. 9, 2015). The severed rate case expense issues are being considered in *Review of Rate Case Expenses Incurred by Southwestern Public Service Company and Municipalities in Docket No. 43695*, Docket No. 44498 (pending).

SPS proposed an effective date of January 12, 2015 for its rate change. The effective date was suspended for 150 days, *i.e.*, until June 11, 2015.[10] SPS initially sought approval of temporary rates as of January 12, 2015, subject to surcharge or refund for usage between January 12, 2015, and the date SPS actually begins charging the final rates established by the Commission.[11] At the December 19, 2014 prehearing conference: (1) SPS withdrew that request; (2) the parties agreed that, if the Commission did not issue a final order by June 11, 2015, SPS's current rates will not change but the final rates set in this case will be made retroactive to June 11, 2015, for consumption occurring on and after June 11, 2015; and (3) SPS agreed to extend the statutory deadline for the Commission's final order from June 11, 2015, to September 30, 2015.[12] To effectuate the parties' agreement, SPS proposed an Ordering Paragraph authorizing SPS to file an application to implement a surcharge to recover the revenue it would have received, under the Commission-approved rates, for service on and after June 11, 2015, through the date rates that are set in this case take effect. No party challenged SPS's proposed Ordering Paragraph, which the ALJs recommend and have included in their recommended Ordering Paragraphs.

On March 30, 2015, after SPS agreed to extend the statutory deadline from September 30, 2015, to October 30, 2015, the ALJs granted a motion to abate the case for 30 days to facilitate settlement negotiations.[13] After the parties were unable to agree on a settlement, SPS agreed to extend the statutory deadline to November 20, 2015.[14] In an October 7, 2015 letter, SPS agreed to extend the statutory deadline to December 4, 2015.

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[10] *See* SOAH Order No. 1 at 1 (Dec. 9, 2014); SOAH Order No. 2 at 2 (Dec. 14, 2014).

[11] *See* SOAH Order No. 1 at 1.

[12] *See* SOAH Order No. 3 at 4 (Jan. 9, 2015).

[13] SOAH Order No. 9 (Mar. 30, 2015).

[14] SOAH Order No. 12 at 1 (Apr. 29, 2015).

The following parties are Intervenors in this docket:

Alliance of Xcel Municipalities (AXM)
Amarillo College
Amarillo Recycling Company, Inc. (ARC)
Canadian River Municipal Water Authority
DOE
Golden Spread
Laurance Kriegel, an individual residential customer
Occidental Permian, Ltd. (OPL)
Office of Public Utility Counsel (OPUC)
Pioneer Natural Resources USA, Inc. (Pioneer)
State of Texas's agencies and institutions of higher education (State Agencies)
Texas Cotton Ginners' Association
Texas Industrial Energy Consumers (TIEC)
Wal-Mart Stores Texas, LLC and Sam's East, Inc. (Wal-Mart)

The hearing on the merits lasted seven days, and was held on June 24 through July 2, 2015.

V. JURISDICTIONAL ALLOCATION

SPS provides service in three separate jurisdictions: Texas (retail); New Mexico (retail); and FERC (wholesale). SPS witness Deborah A. Blair testified that, under well-settled principles of cost causation, customers in a particular jurisdiction pay only the costs associated with providing service to that jurisdiction. Thus, in this case, the revenue requirement ultimately determined for Texas retail customers should include only costs related to the provision of retail utility service in Texas.[15]

[15] SPS Ex. 37, Blair direct at 18-19.

SPS witness Richard M. Luth explained that SPS used three main allocation factors for jurisdictional cost allocation:

1. a production-related 12 Coincident Peak (12-CP) demand allocation factor for the allocation of power production rate base, O&M, depreciation, taxes, and other costs;

2. a transmission-related 12-CP demand allocation factor for the allocation of transmission rate base, O&M, depreciation, taxes, and other costs; and

3. an energy allocation factor for the allocation of production non-fuel energy costs including rate base, O&M, depreciation, taxes, and other costs.[16]

He further explained that demand cost allocation factors are used to allocate among jurisdictions those costs that are caused by the capacity needed to generate and transmit electricity at all times.[17] TIEC witness Jeffrey Pollock explained that the allocation factors used in a jurisdictional separation study reflect each jurisdiction's demand and energy usage. The more power and energy usage by a specific jurisdiction, the higher the allocation factor and the higher the amount of system costs allocated to that jurisdiction.[18]

Three jurisdictional allocations proposed by SPS are contested. The most contested jurisdictional allocation issue relates to SPS's decreased wholesale sales to Golden Spread. The other two contested issues concern disagreements about the allocation of certain FERC accounts. All three are discussed below.

A. Adjustment for Golden Spread

The Commission's cost of service rule provides that "rates are to be based upon an electric utility's cost of rendering service to the public during a historical test year, adjusted for

[16] SPS Ex. 54, Luth direct at 23.

[17] SPS Ex. 54, Luth direct at 23-24.

[18] TIEC Ex. 1, Pollock direct at 32.

known and measurable changes."[19] A "test year" is defined as "the most recent 12 months, beginning on the first day of a calendar or fiscal year quarter, for which operating data for a public utility are available."[20] SPS bears the burden of proving that its requested rates are just and reasonable.[21]

1. Background

In late 2004, six electric cooperatives—the four eastern New Mexico cooperatives, Golden Spread, and Lyntegar Electric Cooperative, Inc.—jointly filed a complaint against SPS at FERC alleging that they had first call on SPS's lower-cost electricity over SPS's other wholesale customers. Ultimately, the dispute between the cooperatives and SPS pending at FERC was resolved through a series of settlements concluding in 2010. These settlements included the execution of reduced power supply contracts with Golden Spread and the New Mexico cooperatives. At issue here is the reduced power supply contract between SPS and Golden Spread, which began in 2012 and terminates in 2019. As of June 1, 2015, after the Test Year, SPS's annual sale obligation to Golden Spread declined or "ramped down" from 500 megawatts (MW) to 300 MW. Pursuant to the contract, SPS's annual sales to Golden Spread will reduce by an additional 100 MW in 2017 and sales will cease altogether in 2019.[22]

SPS witness Evan D. Evans explained how the June 1, 2015 ramp down affected SPS's jurisdictional customers:

> [T]he wholesale power sale reduction [to Golden Spread] frees up lower-embedded cost capacity and energy for the use of retail customers. It will no longer be necessary for SPS to produce or procure at incremental cost the energy to serve this load. The reduction of sales to a wholesale customer reduces the

[19] 16 TAC § 25.231(a).

[20] PURA § 11.003(20).

[21] PURA § 36.006.

[22] SPS Ex. 6, Evans direct at 59-61.

> peak demand of wholesale customers. Thus, the ratio of the Texas retail jurisdiction's peak demand to overall peak demand increases, as does the New Mexico retail jurisdiction's peak demand. Because many of the costs included in SPS's revenue requirement are allocated based on peak demand, the ramp down of the Golden Spread contract means that Texas and New Mexico retail customers should bear more of the fixed costs, since they are receiving the fuel savings immediately effective June 1, 2015.[23]

SPS requests that its jurisdictional cost allocators be adjusted so that a larger portion of SPS's embedded costs is assigned to the Texas and New Mexico retail jurisdictions. Because the ramp down occurred after the Test Year, SPS is seeking a known and measurable adjustment to its jurisdictional demand allocation factors. SPS witness Mr. Luth testified that he reduced the wholesale production demand and energy during the Test Year to account for the 200 MW decrease in SPS's firm power commitments to Golden Spread. The reduction increased the Texas energy allocation factor from 53.7737% to 54.8994% and increased the Texas production demand factor from 49.9364% to 52.4078%.[24] These changes increased Texas retail revenue requirements by approximately $11.1 million.[25]

In support of SPS's request for a known and measurable adjustment, Mr. Evans testified that the series of reductions in various wholesale loads provided SPS's retail customers with fuel savings (because more lower-cost generation would be available to retail customers) and delayed SPS's need to obtain new generating resources that would be more expensive than existing resources. Mr. Evans testified that it is fair and reasonable for the Commission to approve the requested known and measurable adjustment.[26]

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[23] SPS Ex. 39, Evans rebuttal at 41.

[24] SPS Ex. 54, Luth direct at 27; TIEC Ex. 1, Pollock direct at 32-34.

[25] TIEC Ex. 1, Pollock direct at 33.

[26] SPS Ex. 38, Evans rebuttal at 40.

2. Opposition to SPS's Proposed Adjustment and SPS Response

TIEC, AXM, OPUC, State Agencies, OPL, and Staff oppose the Golden Spread adjustment. TIEC articulated the importance of this issue:

> The use of a historical test year in ratemaking is important for at least two reasons. First, it allows the Commission to review a utility's *actual* costs and revenues, rather than various competing predictions about what its costs and revenues will be in some future period. As the Commission stated in the recent Entergy Texas, Inc. (ETI) rate case, 'The point of a historical test year is to review actual costs, which include the ups and downs of what actually occurred.' Rates are set for an indefinite period into the future generally until a utility elects to file another rate case. There is no true-up or reconciliation for expenses recovered in a utility's base rates. Consequently, the use of speculative projections of future costs and revenues could result in captive ratepayers being overcharged for years with no prospect of a refund.
>
> . . .
>
> Second, test-year ratemaking allows for an accurate matching of a utility's costs in a particular period with its sales in the same period. This is important because of the way in which a utility recovers its non-fuel costs through base rates. Specifically, each kilowatt (kW) or kilowatt hour (kWh) billed to customers recovers a certain amount of fixed costs. Accordingly, as a utility's kW or kWh sales increase, so do the utility's base revenues, without any change to its rates. Utilities experiencing load growth will generally experience an increase in their *total* base rate costs, even if their per-unit costs remain the same, simply because they are serving more load. But they will also receive more revenues from additional sales to cover these costs. Conversely, a utility experiencing a reduction in its load may experience offsetting cost reductions in, for example, purchased power costs. Thus, in setting rates, the time period used for expenses must match the time period used for revenues. This fundamental tenet of ratemaking, called the 'matching principle,' was applied in the Commission's order in Docket No. 39896, in which the Commission found it 'logically inconsistent' that ETI based its purchased power costs on estimates in a future period while using the historical test year sales level to develop the per-unit rates.[27]

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[27] TIEC initial brief (RR) at 8-9 (emphasis in original, citations removed).

TIEC argues that, in 40 years of Commission cases considering jurisdictional allocations, there is no example of the Commission approving PTYAs to jurisdictional allocators. According to TIEC, this is because there are thousands of moving parts in multiple jurisdictions that affect jurisdictional allocators.

TIEC witness Mr. Pollock stated that it is inappropriate to recognize a PTYA in an existing customer's load because a utility's customer base is always changing. He noted that existing customers may change consumption levels up or down, and there is no particular reason to recognize a change in one customer's service. Mr. Pollock also testified that SPS failed to recognize all attendant impacts of the Golden Spread adjustment to jurisdictional allocation factors. For instance, Mr. Pollock suggested that the reduction in load will free up capacity resources to serve additional retail load and create opportunities for off-system sales in the wholesale markets.[28] According to TIEC, SPS's proposal is unprecedented and based on speculation about Texas's future share of costs. As such, it should not be allowed.

TIEC also notes that, in a recent filing before the New Mexico Commission, SPS offered sworn testimony that SPS's New Mexico load is growing and Texas's jurisdictional share of load will decrease.[29] The comparison of the Texas allocators (1) as filed by SPS, (2) based on the actual Test Year without the Golden Spread adjustment, and (3) based on SPS's recent New Mexico filing is as follows:[30]

Jurisdictional Allocation

	SPS Adjusted Test Year	Test Year Actual	SPS New Mexico Filing
Texas kWh	54.9%	53.8%	53.3%
Texas kW	52.4%	49.9%	50.1%

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28 TIEC Ex. 1, Pollock direct at 30-33.

29 *In the Matter of Southwestern Public Service Company's Application for Revision of its Retail Rates under Advice Notice No. 255,* Case No. 15-00139-UT (filed June 9, 2015), TIEC Ex. 20, Att. ICF-1.

30 *Compare* TIEC Ex. 17 *with* TIEC Ex. 20, Att. ICF-1.

AXM witness Clarence Johnson explained that a fundamental characteristic of an equitable cost of service study matches jurisdictional loads, plant, and expense over a consistent time period. Thus, the reduction of Golden Spread load is meaningful only as a ratio in relation to the combined loads of other SPS customers. He agreed with Mr. Pollock that one cannot quantify the changes and fluctuations in other wholesale customers' and New Mexico loads in 2015. Thus, singling out the jurisdictional effect of a load reduction without taking into account other customers' changes in load is likely to produce an inaccurate jurisdictional allocation.[31]

Staff witness Brian T. Murphy also recommended against the Golden Spread adjustment. Mr. Murphy testified that, "In the rate year, a decrease in *Texas retail* load may offset a decrease in wholesale load. To ensure the [jurisdictional cost of service] is representative, it would be necessary to forecast Texas retail and wholesale load."[32] In fact, he noted that a number of scenarios could occur: expenses and plant investments could decrease or SPS's New Mexico load may offset decreases in wholesale load. He pointed out that SPS used an adjusted historical Test Year, not forecasted retail load, which violates the matching principle by mixing rate year wholesale load with Test Year cost of service.[33] In sum, Mr. Murphy suggested that:

> The Company has not shown that the isolated post-test year adjustment to the [Golden Spread] load will result in a [jurisdictional cost of service] that is more representative of conditions that are apt to prevail in the rate year. To perform the adjustments properly, perfect forecasts of system loads, costs, and revenues would be required. Forecasted costs and loads are subject to error and are not countenanced in the Commission's Rules, which do not provide for the use of forecasted Test Years and forecasted usage information in base rate proceedings.[34]

In response, SPS argues it is unreasonable to ignore a known and significant 200 MW reduction in load simply because other changes might occur at some unknown future time.

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[31] AXM Ex. 6, Johnson direct at 7.

[32] Staff Ex.1A, Murphy direct at 20 (emphasis in original).

[33] Staff Ex.1A Murphy direct at 21-22.

[34] Staff Ex. 1A, Murphy direct at 23.

According to SPS, the attendant impact associated with the Golden Spread adjustment is a reduction in fuel costs, which SPS's customers are already receiving.

Mr. Evans stated that the attendant impact needs to be known and measurable and even Mr. Pollock admitted that he does not know what additional sales SPS will be able to make as a result of the Golden Spread rampdown. Moreover, he noted that SPS's retail customers will be credited for margins that SPS would make on any off-system sales due to additional capacity. Such margins are credited to fuel and there are no associated base rate adjustments.[35]

3. ALJs' Analysis and Recommendation

A known and measurable change is a transaction or event that is: (a) fixed in time; (b) known to occur (not speculative, possible, or uncertain); and (c) measurable in amount.[36] All parties agree the Golden Spread ramp down is fixed in time and known to occur: as of June 1, 2015, SPS experienced a 200-MW reduction in wholesale sales. As Mr. Evans testified, the reduction of 200 MW in sales to a wholesale customer reduced the peak demand of wholesale customers. Thus, the ratios of both the Texas and New Mexico retail jurisdictions' peak demand to overall peak demand increased, and SPS calculated that change in its proposed jurisdictional allocators. No party argued, and no witness testified, that Mr. Luth failed to properly calculate the new allocation factors. Rather, the parties contend that the adjustment should not be performed because SPS failed to take into account attendant impacts.

But no witness testified as to what those impacts would be. Rather, they noted that load growth changes or fluctuates within and among the jurisdictions and suggested that, because SPS cannot measure such changes with certainty, it cannot meet the requirement of taking into account all attendant impacts. This argument is unpersuasive to the ALJs because no opposing witness tied any future load growth changes to the 200-MW reduction. The ALJs recognize that SPS bears the burden of proof. Staff and Intervenors would not be required to calculate an

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[35] SPS Ex. 38, Evans rebuttal at 46.

[36] AXM Ex. 5, Carver direct at 9.

attendant impact, but they bear the burden of bringing forward persuasive evidence that an attendant impact exists. They did not. It is insufficient to suggest that freed up capacity *could* translate into additional sales for SPS or that there may be other unaccounted for facts that *may* offset the loss of Golden Spread load. If SPS had contracted with another wholesale buyer, that contract would be known and measurable and could be accounted for in the allocators. In fact, Mr. Evans agreed that if SPS had gained another 200-MW wholesale customer, the allocation factors should not change.[37] But there is no evidence this has occurred.

The ALJs are not convinced that SPS's testimony in a New Mexico case, which is based on a forecast of the 2016 load, should bear on this issue. First, SPS's forecast in the New Mexico case is just that—a forecast—and it is therefore not known or measurable with reasonable certainty. Second, while the load for New Mexico may increase in 2016, no party is suggesting that SPS's unadjusted Test Year allocators (the jurisdictional allocators Mr. Luth calculated before the Golden Spread adjustment) should have taken into account the New Mexico forecast for 2016. The ALJs acknowledge that TIEC is using the New Mexico forecast to cast doubt on the change of allocators in this case, but SPS's forecast that New Mexico's load will increase also casts doubt on Mr. Luth's unadjusted, Test Year jurisdictional allocators. The ALJs conclude that TIEC's argument is not persuasive.

The arguments against the Golden Spread adjustment reflect the opinion that, without taking into account other customers' changes in load, the jurisdictional allocation may be inaccurate. But this is the nature of allocating costs based on demand and energy usage. Such usage fluctuates. However, the Golden Spread ramp-down has occurred and its impact on demand usage is measurable. Taking into account the change will make the Test Year as representative as possible to the cost situation expected in the future.[38]

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[37] Tr. at 108-109.

[38] *El Paso v. Pub. Util. Com'n*, 883 S.W.2d 179, 188 (Tex. 1994); *see also Suburban Util. Co. v. Pub. Util. Com'n*, 652 S.W.2d 358, 366 (Tex. 1983) ("Changes occurring after the test period, if known, may be taken into consideration by the regulatory agency to help mitigate the effects of inflation and in order to make the test year data as representative as possible of the cost situation that is apt to prevail in the future.").

Finally, the ALJs are not persuaded by the witnesses and opposing parties' reliance on the recent Energy Texas, Inc. (ETI) rate case.[39] In that case, the ALJs noted that the known and measurable request is an exception to the actual Test Year data. The ALJs found, and the Commission concurred, that ETI's suggested changes were unknown because there were so many variables. The ALJs also found that ETI's adjustment violated the matching principle. But there is no showing in this case that the Golden Spread adjustment will have a quantifiable impact on retail load growth. Moreover, Mr. Evans testified that if the loss of load impacts margins (based on an increase in off-system sales), the impact will be to fuel revenues.

The ALJs conclude that SPS met its burden of proving that its proposed change in allocation factors to account for the 200-MW loss in wholesale load was known and measurable. The associated attendant impacts of the loss in wholesale load are reductions in system-average fuel costs. Therefore, the ALJs recommend that SPS's jurisdictional allocation be adjusted as calculated by Mr. Luth.

B. General and Intangible Plant

1. General and Intangible Plant Defined

SPS witness Ms. Blair testified that intangible plant costs are found in FERC Account 303. According to the FERC Uniform System of Accounts, FERC Account 303 includes the costs of patent rights, licenses, privileges, and other intangible property necessary or valuable in the conduct of utility operations. Ms. Blair stated that the majority of costs recorded in FERC Account 303 are for capitalized software. These include costs for software systems that support SPS's operations, such as: (1) accounting systems, including the general ledger, payroll, accounts payable, etc.; (2) human resource systems; (3) outage management systems; (4) work management systems; (5) resource management systems; and (6) customer billing systems. She

[39] *Application of Entergy Texas, Inc. for Authority to Change Rates, Reconcile Fuel Costs, and Obtain Deferred Accounting Treatment,* Docket No. 39896, Order on Rehearing (Nov. 1, 2012).

also testified it is reasonable to allocate such costs based on operating labor, which is what these software systems are supporting.[40]

Ms. Blair explained that general plant consists of the following FERC accounts:[41]

FERC Account	Type of Plant
389	Land and Land Rights
390	Structures and Improvements
391	Office Furniture and Equipment
392	Transportation Equipment
393	Stores Equipment
394	Tools, Shop, and Garage Equipment
395	Laboratory Equipment
396	Power Operated Equipment
397	Communication Equipment
398	Miscellaneous Equipment

According to Ms. Blair, FERC equipment accounts (Accounts 391-398) are tied to the needs of employees, not to the amount of production, transmission, or distribution plant. For example, the costs incurred for the Office Furniture and Equipment, Transportation Equipment, and Communications Equipment FERC accounts are caused by the needs of employees for such things as desks, chairs, cars, telephones, computers, etc., not by the number of SPS power plants or miles of transmission lines.[42] SPS argues that the use of a labor-based allocator is consistent with cost-causation principles because general and intangible costs are driven largely by the needs of employees. In contrast, it makes no sense to allocate those costs based on plant in service because they are not physical plant and do not support physical plant.

[40] SPS Ex. 53, Blair rebuttal at 21-22.

[41] SPS Ex. 53, Blair rebuttal at 22-23. AXM witness Mr. Johnson also explained that general plant consists of building and associated plant that cannot be identified by particular functions. AXM Ex. No. 6, Johnson direct at 8.

[42] SPS Ex. 53, Blair rebuttal at 23.

2. Evidence and Argument

AXM notes that SPS historically allocated general and intangible plant in its jurisdiction study on the basis of total plant in service or Production-Transmission-Distribution plant in service (PTD-PIS). AXM witness Mr. Johnson recommended continuation of this practice. According to Mr. Johnson, SPS has used the same allocator for general and intangible plant in prior cases and has not justified the use of a different allocator in this case. Mr. Johnson suggested that, ideally, SPS should perform studies to measure the portion of general structures devoted to particular functions so it could directly assign plant cost to a particular function, production, transmission, distribution, or customer. However, SPS has directly assigned only the call center portion of general plant to customers.[43]

Mr. Johnson stated that the Electric Utility Cost Allocation Manual prepared by the National Association of Regulatory Utility Commissioners (NARUC) supports the use of a PTD-PIS allocator for general and intangible plant. He indicated that a labor allocation, used by SPS in this case, can produce distorted results if it is used as a way to spread general costs across a utility's major functions. A labor-based allocator tends to over-assign costs to functions, such as customer operations, which are more labor intensive than capital intensive.[44]

Mr. Johnson also relies on the Commission's Rate Filing Package (RFP) for investor-owned Transmission and Distribution Utilities (TDUs) to support his recommendation that general and intangible plant should be allocated using the PTD-PIS allocation factor. While he admitted that the form for TDUs does not apply to SPS, an integrated utility, he suggested that the recommended allocation methods are informative. The TDU RFP requires direct assignment, if feasible, of general plant to functions based on the square footage use of general structures and an allocation in proportion to the utility's total plant costs of any general plant that cannot be directly assigned.[45]

[43] AXM Ex. 6, Johnson direct at 8.

[44] AXM Ex. 6, Johnson direct at 9.

[45] AXM Ex. 6, Johnson direct at 9.

In response, SPS argues that it is constantly updating its allocation methods to determine whether there is a better way to allocate costs among jurisdictions. SPS contends that forcing it to retain the same allocation method simply because it used that method in the past would prevent improvement in allocation methods, even when new information comes to light or SPS discovers a better cost allocation method. SPS witness Ms. Blair testified that SPS is using its proposed labor-based allocator for its wholesale customers and is proposing the same allocation method in this rate case and in its pending New Mexico rate case. Ms. Blair stated that a consistent allocation basis among SPS's three jurisdictions: (1) provides SPS the opportunity to recover its full costs of general and intangible plant; and (2) eliminates any opportunity for SPS to over-recover costs by using inconsistent allocators in the three jurisdictions.[46]

Ms. Blair also testified that the NARUC Electric Utility Cost Allocation Manual expressly provides that it is appropriate to use a labor-based allocator for General Plant accounts:

> In performing the cost of service study, operation and maintenance expenses for production, transmission, distribution, customer accounting and customer information have already been functionalized, classified, and allocated. Consequently, the amount of labor, wages, and salaries, assigned to each function is known, and a set of labor expense ratios is thus available for use in allocating accounts such as transportation equipment, communication equipment, investments or general office space.[47]

According to Ms. Blair, Mr. Johnson's reliance on the NARUC manual is misplaced. Although the manual indicates that one approach to the allocation of general plant is on the basis of PTD-PIS, it also states that the use of operating labor ratios is another basis. Ms. Blair concluded that NARUC acknowledges there is more than one reasonable way to allocate general plant.[48]

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[46] SPS Ex. 53, Blair rebuttal at 21.

[47] SPS Ex. 53, Blair rebuttal at 24, *citing* NARUC Electric Utility Cost Allocation Manual at 105.

[48] SPS Ex. 53, Blair rebuttal at 24.

Ms. Blair also disputes Mr. Johnson's claims that SPS's direct assignment of the investment in the call center minimizes the rationale for favoring a labor-based allocator. The direct assignment of SPS's call center reflects that the call center is not utilized for SPS's wholesale jurisdiction, because SPS's wholesale customers do not call the call center—instead, they call their wholesale account managers. Thus, SPS's jurisdictional cost of service study directly assigns the call center costs to SPS's retail jurisdictions, and then it allocates the costs between Texas and New Mexico based on an average retail customer-based allocation methodology. According to Ms. Blair, the direct assignment of the call center costs to SPS's retail jurisdictions does not suggest that a labor-based allocation for General and Intangible Plant is inappropriate. In fact, direct assignment of the call center costs to only SPS's retail jurisdictions is a preferred allocation methodology because it achieves a basic cost allocation principle to directly assign costs to the extent possible.[49]

3. ALJs' Analysis and Recommendation

SPS changed its allocator for general and intangible plant and provided only general statements as to why it made this change. One general but persuasive reason is that SPS uses this allocator before FERC and is proposing the same allocator in New Mexico. Thus, Ms. Blair's testimony that consistent allocation among SPS's three jurisdictions provides benefits is convincing. Moreover, the use of a labor-based allocator as proposed by SPS is supported by the NARUC Electric Utility Cost Allocation Manual (as is SPS's previous allocator). Mr. Johnson's concern that SPS's changed allocation method is not the same as the method used in the Commission's TDU RFP form is not persuasive: the TDU form does not apply to a vertically integrated utility. For these reasons, the ALJs find SPS's allocator known as Labor Excluding Administrative and General Labor should be adopted.

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[49] SPS Ex. 53, Blair rebuttal at 26.

C. Account 923—Outside Services: Legal and Contributions and Dues

SPS allocates outside services and contributions and dues based on a labor classification. These accounts represent only a generalized cost of doing business (for instance, they do not include legal fees for rate cases). For outside services, this is the same method used in SPS's jurisdictional study.[50]

SPS witness Ms. Blair testified that FERC Account 923 includes more than outside legal expenses. It also includes expenses for fees and expenses of professional consultants, including, for example, auditors, actuaries, management consultants, and tax consultants. These expenses are for professional consultants engaged for special or temporary administrative or general purposes. SPS uses outside labor when the need exceeds the capacity of in-house employees or because SPS does not have in-house expertise. According to Ms. Blair, these expenses should not be allocated differently than in-house labor, as these expenses are a substitute for existing labor. SPS also uses a labor-based allocation methodology to allocate FERC Account 923 in its FERC-approved formula rates and in its New Mexico rates. She again noted that a consistent allocator across jurisdictions eliminates any opportunity for SPS to over-recover costs.[51]

AXM witness Mr. Johnson contends that the outside legal expenses recorded in FERC Account 923 should be allocated on the basis of total O&M expense minus fuel and purchased power (TOMXFPP), instead of on the basis of labor. Mr. Johnson's rationale is the same as his recommendation for general and intangible plant. He stated that the labor-based allocation over-assigns costs to the distribution function and understates costs that should be assigned to the transmission function. He also found the Commission's TDU RFP form provided guidance for his recommended change.

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[50] AXM Ex. 6, Johnson direct at 17-18.

[51] SPS Ex. 53, Blair rebuttal at 26-27.

The ALJs find sufficient evidence that SPS's use of a labor-based allocator is reasonable. As Ms. Blair testified, these expenses should not be allocated differently than in-house labor. Moreover, there is some benefit for the use of the same allocator for this account in all three jurisdictions. Accordingly, the ALJs do not recommend a change to the proposed jurisdictional allocation of FERC Account 923.

VI. RATE BASE

A. Post-Test Year Adjustments for Capital Additions After June 30, 2014

Currently, SPS seeks PTYAs to rate base for $392,549,024 of capital additions placed in service during the first six months after the Test Year ended (*i.e.*, during July 1, 2014 through December 31, 2014).[52] SPS's proposed PTYAs include:

- capital additions that closed to plant-in-service during those six months even if the project was not under construction when the Test Year ended; and
- the dollar amount of the capital additions as of December 31, 2014, rather than as of June 30, 2014, when the Test Year ended.[53]

SPS's PTYA proposal would increase its Texas retail revenue requirement by approximately $8.9 million.[54] Conceding that its proposal does not meet two requirements of the Commission's PTYA rule, 16 TAC § 25.231(c)(2)(F), SPS requests good cause exceptions from both requirements. AXM, OPL, OPUC, State Agencies, TIEC, and Staff oppose the proposed PTYAs and SPS's requests for good cause exceptions. The ALJs recommend rejecting the PTYAs, which clearly violate the language and intent of the PTYA rule, and find that SPS has not shown good cause for its requested exceptions.

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52 SPS Ex. 11B; SPS Ex. 53, Blair rebuttal at 29; SPS Ex. 38, Evans rebuttal at 15.

53 SPS Ex. 6, Evans direct at 53.

54 Tr. at 332-334; TIEC Exs. 7, 33; AXM Ex. 11.

1. Law Applicable to SPS's Proposed PTYAs

a. The PTYA Rule

The PTYA rule requires that, for a PTYA to be *considered*, each rate base addition must meet certain requirements. 16 TAC § 25.231(c)(2)(F)(i) states:

> Post test year adjustments for known and measurable *rate base additions* (increases) to historical test year data will be *considered only* as set out in subclauses (I)-(IV) of this clause.
>
> (I) Where the addition represents plant which would be appropriately recorded . . . in FERC account 101 or 102 . . . .
>
> (II) Where *each addition* comprises at least 10% of the electric utility's requested rate base, exclusive of post test year adjustments and CWIP [construction work in progress].
>
> (III) Where the plant addition is deemed by this commission to be in-service before the rate year begins.
>
> (IV) Where the *attendant impacts* on all aspects of a utility's operations (including but not limited to, revenue, expenses and invested capital) can with *reasonable certainty be identified, quantified and matched*. Attendant impacts are those that reasonably follow as a consequence of the post test year adjustment being proposed.[55]

The disputes in this case focus on subparts (II), the *10% requirement* (from which SPS seeks a good cause exception), and (IV), the *attendant impacts requirement* (which SPS claims it has met while other parties dispute that claim). The other requirement for which SPS seeks a good cause exception is 16 TAC § 25.231(c)(2)(F)(ii), the *test-year-end CWIP balance requirement,*

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[55] (Emphasis added). All four of Subclauses (I) to (IV) must be satisfied for a PTYA to be approved. *Application of Southwestern Electric Power Company to Change Rates and Reconcile Fuel Costs*, Docket No. 40443, PFD at 50 (May 20, 2013); *see also* Docket No. 40443, Order on Rehearing Finding of Fact Nos. (FFs) 83-91 (Mar. 6, 2014). SPS has not disputed that point.

which states: "Each post test year plant adjustment will be included in rate base at: (I) the reasonable test year-end CWIP balance, if the addition is constructed by the electric utility; . . ."

At its June 26, 1996 open meeting, before voting to adopt the PTYA rule, Commission Chairman Patrick Wood III and Commissioners Robert W. Gee and Judy Walsh discussed the rule's purposes regarding matters relevant here:

> COMM. GEE: . . . I think that what we have to remember historically is the reason why we have allowed for the deviation was because this commission went through an unusual era of a large nuclear power plant construction era, and this rule was adopted at a time to accommodate the problems associated with regulatory lag. . . .
>
> COMM. WALSH: And this is a relief provision and the 10 percent is there to keep people from just dragging in a bunch of de minimus stuff.
>
> CHAIRMAN WOOD: Boy, that will stretch those hearings out for months. . . .
>
> COMM. GEE: My experience has been that this has just opened the door to provide fodder for litigation, just–and having to match and having to try to coordinate, you know, an expense with . . . an entitlement to revenues is just a–it's a nightmare. And matching all the effects of allowing a particular event to occur within this deviation, it's just–it's a nightmare. . . . I used to represent utilities. They knew exactly when they needed to put an item into rate base and they had people preparing a rate case . . . in order to get it put in in time.[56]

Similarly, in its 1996 preamble to the PTYA rule, the Commission stated:

> The amendments . . . should result in a reduction of issues for resolution in rate proceedings, which in turn should result in reduced rate case expenses. . . . The 10% of total rate base threshold was established with the utilities' overall financial integrity in mind. . . . [T]he commission's intent [is] to focus on each utility's overall financial integrity, and eliminate litigation related to immaterial adjustments.[57]

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[56] Staff Ex. 9B at 14 (Open Meeting Tr. at 249-251 (Jun. 26, 1996)).

[57] 21 Tex. Reg. 6454 (Jul 12, 1996).

16 TAC § 25.231, which includes the PTYA rule, was last amended effective April 13, 2005.[58] Eight days before that, the Commission issued an order rejecting the Lower Colorado River Authority's (LCRA) request for PTYAs for certain transmission projects.[59] The Commission explained that "[a]djustments to a utility's test year cost of service for known and measurable post test year adjustments [are] allowed only under very limited circumstances."[60]

In a 2011 case, CenterPoint Energy Houston Electric, LLC (CenterPoint) requested PTYAs for rate base additions that did not meet the 10% requirement.[61] CenterPoint's request for a good cause exception to the 10% requirement was denied for reasons which include that the request "amounted to little more than a challenge to the Commission's rule."[62]

Last year, the Commission allowed Southwestern Electric Power Company (SWEPCO) a PTYA for a large new power plant that met the 10% requirement, but rejected PTYAs for two transmission projects associated with the new plant because neither met the 10% requirement.[63]

b. Standard for Good Cause Exceptions to the PTYA Rule

16 TAC § 25.3 states: "The commission may make exceptions to this chapter for good cause." Reading 16 TAC § 25.3 in harmony with the PTYA rule, and considering the Commission's stated purposes for the PTYA rule, the ALJs reach the following conclusions.

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[58] http://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.231/25.231.pdf, last visited on August 28, 2015. Recent legislation addressing the 10% requirement for new or recently acquired gas generation applies only to rate cases filed on or after September 1, 2015, and thus does not apply to this case. Acts 2015, 84th Leg., R.S., ch. 733 (HB 1535) (to be codified in the Texas Utilities Code); TIEC Ex. 25 (copy of House Bill 1535); Tr. at 151.

[59] *Application of the LCRA Transmission Services Corporation to Change Rates*, Docket No. 28906, Order at 6 (Apr. 5, 2005).

[60] Docket No. 28906, Order at 6.

[61] *Application of CenterPoint Energy Houston for Authority to Change Rates*, Docket No. 38339, PFD at 10 (Dec. 3, 2010) (adopted without comment in Docket No. 38339, Order on Rehearing (Jun. 23, 2011)).

[62] Docket No. 38339, PFD at 10.

[63] Docket No. 40443, Order on Rehearing, FFs 83-91.

First, a good cause exception to the PTYA rule requires unusual facts, not arguments rejected when that rule was adopted. As noted above, CenterPoint's request for a good cause exception from the 10% requirement was denied because it "amounted to little more than a challenge to the Commission's rule." If disagreement with the PTYA rule were good cause for an exception to it, then merely by phrasing a PTYA request as a request for good cause exception, a utility could defeat the Commission's stated purpose of reducing rate case litigation over immaterial PTYAs. Many of SPS's good cause arguments are in essence simply challenges to the PTYA rule's requirements and the Commission's stated reasons for imposing them. For example, SPS witness Mr. Evans:

- stated that the PTYA rule, as written, is inadequate to meet SPS's needs and complained that parties opposing the PTYAs are "trying to hide behind the letter of the Commission's rules . . ."
- argued that there is good cause for SPS's requested exceptions because most of SPS's PTYAs are for transmission additions and "[b]ecause transmission and distribution projects can take far less time to complete than a generation project, it is possible that little or none of the investment in some projects was in CWIP at the end of the Test Year";
- argued that undertaking dozens of projects at once, which amount to an equivalent total investment, can threaten a utility's financial integrity as readily as one large project can; and
- observed that by the time rates set in this case take effect, customers will have been receiving the benefit of some of those projects for nearly a year and all of the projects for at least six months.[64]

Second, a good cause exception to a PTYA rule requirement is not warranted when the utility's proposal exemplifies the problem the Commission anticipated and tried to avert by adopting that requirement. The ALJs find that SPS's proposed PTYAs exemplify the problem the Commission sought to avert by adopting the PTYA rule requirements for which SPS seeks good cause exceptions. SPS requests PTYAs for hundreds of rate base additions that do not meet the 10% requirement, some of which involve very small dollar amounts. Seeking PTYAs

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[64] SPS Ex. 6, Evans direct at 52; SPS Ex. 38, Evans rebuttal at 10, 16, 20, 54.

for rate base additions placed in service and costs closed to book as late as December 31, 2014, SPS substantially revised its Application months after it was filed on December 8, 2014. In contrast, the ALJs expect that a utility that complied with the PTYA rule could propose PTYAs for only a very small number of rate base additions because the test-year-end CWIP balance for each addition would have to comprise at least 10% of its requested rate base, exclusive of PTYAs and CWIP. The ALJs also expect that a utility that complied with the test-year-end CWIP balance requirement would have access to the test-year-end data early enough to file its final PTYA proposal and supporting testimony and workpapers *with its application.*

Third, a showing that rate base additions for which a utility proposes PTYAs _*total*_ *at least 10% of its requested rate base does not establish good cause.* Otherwise, the 16 TAC § 25.231(c)(2)(F)(i) requirement that PTYAs will be "*considered only*" if "*each addition* comprises at least 10% of the electric utility's requested rate base" would be meaningless.[65] This is another example where a utility could defeat the Commission's stated purpose to "eliminate litigation related to immaterial adjustments." As Commissioner Walsh observed: "the 10 percent is there to keep people from just dragging in a bunch of de minimus stuff."

Fourth, financial integrity might provide the basis for a good cause exception to the PTYA rule, but unusual facts are required. For example, the Commission might find good cause where, without a PTYA, a utility could not fund rate base additions needed to provide adequate service. Regulatory lag in recovering substantial investment in smaller (less than 10% of rate base) additions does not constitute good cause. Some regulatory lag is inherent to allow adequate time for review of a rate application,[66] and as SPS witness Mr. Evans acknowledged,

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[65] (Emphasis added.) *See City of San Antonio v. City of Boerne*, 111 S.W.3d 22, 29 (Tex. 2003) ("It is an elementary rule of construction that, when possible to do so, effect must be given to every sentence, clause, and word of a statute so that no part thereof be rendered superfluous or inoperative." (citation omitted), *TGS-NOPEC Geophysical Co. v. Combs*, 340 S.W.3d 432, 438 (Tex. 2011) ("We further interpret administrative rules, like statutes, under traditional principles of statutory construction.").

[66] *See, e.g., R.R. Comm'n of Tex. v. Lone Star Gas Co.,* 656 S.W.2d 421, 424-425 (Tex. 1983).

utilities are constantly adding plant.[67] As noted above, the PTYA rule preamble states that "the commission's intent to focus on each utility's overall financial integrity, and eliminate litigation related to immaterial adjustments" and that "[t]he 10% of total rate base threshold was established with the utilities' overall financial integrity in mind."

In any event, the ALJs need not apply a strict good cause standard to find that SPS has not met it. As discussed subsequently, the evidence shows the PTYAs are not necessary to SPS's financial integrity.

2. Evidence Regarding SPS's Proposed PTYAs

As shown below, changes in SPS's PTYA proposal account for most of the large post-Application reduction in SPS's requested *base rate revenue increase*:[68]

Timing of SPS's Requested Base Rate Revenue Increase	Base Rate Revenue Increase	Base Rate Revenue Increase from Proposed PTYAs
December 2014 (Application)	$64.75 million	$29.7 million
March 2015 (case update)	$58.85 million	$23.8 million
June 2015 (rebuttal case)	$42.07 million	$8.9 million

Transmission additions account for most of the dollar amount of SPS's proposed PTYAs to *rate base*, but SPS also requests PTYAs for additions such as software:[69]

67 Tr. at 62.

68 Tr. at 332-334; SPS Ex. 6, Evans direct at 51; SPS Ex. 6A, Att. EDE-RR-2, line 3; TIEC Ex. 7, 33; OPUC Ex. 1, Ramas direct at 6-7. These numbers are Texas retail (rounded). They include the impact of the PTYA additions to rate base and of the PTYAs' attendant impacts, such as to property tax expense, estimated by SPS.

69 SPS Ex. 6, Evans direct at 51; SPS Ex. 11B at 1.