PLACE: Held via Videoconference

DATE: Monday, September 14, 2020

TIME: 1:30 A.M. - 4:33 P.M.

DOCKET NO.: E-7, Sub 1214

E-7, Sub 1213

E-7, Sub 1187

BEFORE: Chair Charlotte A. Mitchell, Presiding

Commissioner ToNola D. Brown-Bland

Commissioner Lyons Gray

Commissioner Daniel G. Clodfelter

Commissioner Kimberly W. Duffley

Commissioner Jeffrey A. Hughes

Commissioner Floyd B. McKissick, Jr.

IN THE MATTER OF:

DOCKET NO. E-7, SUB 1214

Application of Duke Energy Carolinas, LLC,

for Adjustment of Rates and Charges Applicable to

Electric Utility Service in North Carolina

Noteworthy Reporting Services, LLC

DOCKET NO. E-7, SUB 1213

Petition of Duke Energy Carolinas, LLC,

for Approval of Prepaid Advantage Program

DOCKET NO. E-7, SUB 1187

Application of Duke Energy Carolinas, LLC,

for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego

VOLUME 22

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P R O C E E D I N G S

CHAIR MITCHELL: Let's go back on the record, please. We are going to resume with questions by Commissioners. We are at Commissioner Duffley.

Whereupon,

CHARLES JUNIS AND MICHAEL C. MANESS,

having previously been duly affirmed, were examined and continued testifying as follows:

EXAMINATION BY COMMISSIONER DUFFLEY:

Q. Good afternoon, Mr. Maness. Most of my questions will be for you today. If I could have you turn to your second supplemental testimony, please; and specifically page 7.

A. (Michael C. Maness) The second supplemental?

Q. Correct.

A. Let me pull that up. Hold on one second.

(Witness peruses document.)

I apologize. I have the first and third up but not the second. Let me grab it real quick.

Q. That's okay.

A. (Witness peruses document.)

Q. And you probably don't need it. If you do, you can -- you can -- we can stop and you can find it.

But according to your testimony on page 7, you state:

"The Public Staff is in agreement with allowing the Company to obtain a carrying charge or carrying cost on coal ash expenditures incurred between rate cases"; is that correct?

A. That's correct.

Q. And in the present case, the Public Staff is in agreement with the sum of approximately $26 million, which represents the carrying charges for coal ash costs incurred between January of 2018 through January of 2020; is that correct?

A. Yes, approximately $26 million. I will say, and I don't know if it's in this supplemental testimony or the original testimony, but I do at least raise the possibility that perhaps the Commission should take those carrying costs into account in future cases in determining the overall amortization period.

Q. Correct. And you came to my next question, which is, is that a new request from the Public Staff from the last rate case?

A. Yes. I don't remember if we made that recommendation in Dominion or not. I'm thinking not, but definitely it's new for the DEC and DEP cases.

Q. Okay. And going back to the $26 million, and if the Commission defers the future ARO coal ash costs beginning in February of 2020, the Public Staff is in agreement for allowing a return or this carrying cost between this rate case and the next rate case; is that correct?

A. If I stated that -- I think I did state that starting from the new point that we would be -- that we would want it potentially taken into account in determining the -- looking at the amortization period. I guess that a part of this is because since the costs are so large, and going from case to case like we have, at least at the beginning, we -- the Commission has started down a certain path. But we don't know if they're going to continue on that path, and then we had the appeal to deal with and other facts and circumstances.

So there might come a time when we would say, we know what's going on happen now, and maybe it will be set up in a way that allowing those carrying costs might not be necessary. But for the time being, we're not opposing that as we go forward until a decision is made on the particular costs considered in each case. Once things settle down a bit and it's been pretty settled how it's going to be handled, then we might make a different proposal.

Q. Right. But sitting here today, if the Commission defers these future coal ash costs, your testimony indicates that the Public Staff is in agreement with allowing a return or carrying charges, because your testimony states it potentially will allow the Company to stay out longer between rate cases; is that an accurate summary?

A. That's one of the reasons, yes, along with the not knowing what the Commission's final determination will be with regard to those costs in that case.

Q. Okay. Thank you. Now if I could have you turn to your third supplemental and settlement testimony.

A. (Witness peruses document.)

Yes.

Q. And if you could go to page 10, and specifically footnote 2.

A. Yes.

Q. If you could help me out here and more fully spell out -- and I think you were doing it with Mr. Mehta this morning somewhat -- what you're trying to say in footnote 2. And specifically, are you saying something different than what you state in the sentences beginning right after footnote 2 to the end of that section which ends on the next page on line 17? Are you saying something different?

A. You're talking about the end of -- oh, to the end of on line 17?

Q. Right. So you see where footnote 2 --

A. Yes.

Q. -- is on line 18?

So in the footnote, are you saying something different than what you state in those next three sentences?

A. No. I think it's just variations of the same. The point of footnote 2 was just to point out that through discovery in this case it's become clear that the -- specifically clear that the Commission -- I mean the Company is deferring expenses that are recorded on its books for purposes of ARO treatment. That they're doing a regulatory deferral of those ARO depreciation expenses. Those -- as the footnote states, a portion of those costs that would have otherwise already been written off to expense absent the Commission's approval of deferral.

So in other words, to illustrate, if they recorded in 2019 a certain amount of ARO depreciation expense, what they do for regulatory purposes for this Commission's jurisdiction is to reverse that entry and record the amount in a regulatory asset, instead, that they don't propose for rate base inclusion, but then when they actually spend money, they reclassify part of that regulatory asset to another regulatory asset representing monies spent that they do propose for rate base inclusion.

And so the genesis of all that is a recording of a regulatory asset that defers ARO depreciation expenses that are recorded on their GAAP and FERC books, and not deferring a piece of the ARO asset, itself.

Q. Okay. Thank you. So I don't plan on asking you detailed questions regarding coal ash recovery. Those have been sufficiently stated in this case, as well as through various briefs of the parties. But I did want to ask you one hypothetical. So -- and it's based upon the positions that the Public Staff has taken.

So, hypothetically, if the Commission were to allow the Company to defer ARO-related coal ash costs amortized over five years -- so, in this case, allow all of the cost, defer over five years with a return like the Company is asking for -- would you agree that the Commission has the authority to do so based upon the positions taken by the Public Staff? Although you might not agree with the decision, would you agree that the Commission has the authority and discretion to make such a determination if supported by the evidence in the record?

A. I believe so. From the point of view of being a regulatory accountant, I believe so. And it sounds to me it would pass legal muster, although I would leave that to our attorneys to make a final conclusion there. But it seems like, to me, that the Commission would have that discretion to do so.

Q. Okay. And --

A. (Charles Junis) I apologize, Commissioner Duffley. Is it okay if I add to that?

Q. Of course. Please add what -- your thoughts.

A. So -- and I agree with Mr. Maness with the exception of that the Commission must take into consideration all of the other material facts. We strongly believe, and this is laid out in the appeal, that the environmental record was not appropriately considered as part of that previous decision.

Q. Okay. Thank you. Turning back to Mr. Maness, if I could change subjects here. So there were some questions and some discussions in this proceeding related to the creation of a run rate for future, you know, coal ash expenditures. And it was in response to DEC's testimony that, if the Commission ruled the same way that it did in the last Dominion Energy North Carolina rate case regarding coal ash recovery, that DEC's credit metrics would suffer and that the Company would be downgraded.

In the last rate case, the Public Staff was opposed to the run rate because of the uncertainty of costs involved, and I've also heard you state this morning -- or this morning with Mr. Mehta, it would complicate the equitable sharing position of the Public Staff.

Do you agree that the cost -- or the coal ash costs and future expenditures are more certain now than at the time of the last rate case?

A. (Michael C. Maness) With regard to future expenditures?

Q. Correct.

A. Well, I'm certain that there's probably still a degree of volatility. We have had some legal decisions by DEQ that have maybe made it a little more certain. But I hesitate to say it's a whole lot more certain, because we still don't know what we're going to run into in terms of technical and maybe legal issues in future years.

Q. But at the time of the last rate case, we did not know the closure plans for any of the basins, correct? We did not know whether it would be cap in place or some other type of closure plan or excavation, correct?

A. I think there have been some preliminary decisions made, but those were still subject to change and, in fact, have been changed since that last case.

Q. And since the last case, Duke has entered into agreement with DEQ, correct?

A. Yes.

Q. Okay. Thank you. So there probably -- I heard you say that you think there's still some volatility there, but in the sense of rate volatility between cap in place versus excavation, those decisions have been made between the two rate cases, correct?

A. I think that's generally true. That would still leave volatility over time as different projects get started and finished.

Q. So in your opinion, should the run rate -- should the Commission revisit the run rate at this point, or should the Commission just continue with the spend, defer, and recover mechanism?

And specifically what I'd like to hear when you answer, whether the Commission should look at this other type of recovery mechanism and compare the two recovery mechanisms, like, what would be some of the benefits of allowing some portion of the ongoing coal ash costs to be collected as an expense in base rates, and then what would be some of the challenges, concerns, or pitfalls of allowing such a mechanism?

A. Well, preliminarily, I would state, as sort of an overall statement, that had the Public Staff still does not support a run rate. And I can't see us changing that position or even considering changing it prior to the previous cases coming back with a decision or a remand from the Supreme Court and then getting put back before the Commission to decide if anything needs to be done in regard to the Supreme Court's opinion.

After that, it -- I don't think it can be denied that if it is known what the expense or the pattern of recovery of costs should be from the customers, that there is some benefit to having that being recovered in a timely manner. That that is some benefit. I would say that I don't think we should -- or I don't think the Commission should consider doing that without some sort of true-up and deferral mechanism at this point, because I don't think the costs are certain enough to -- and, I mean, just expressing my personal opinion now. I don't think the costs are certain enough or level enough over time to simply have a run rate that wouldn't take in -- wouldn't look at looking at having that trued up through some sort of annual mechanism, or at least something that would occur in a rate case.

I do think also that to the extent that the Commission does make a decision in Duke in these cases eventually similar to what the Public Staff has recommended or similar to what Dominion has recommended, that we're going to have to take great care if there is going to be any sort of run rate to factor in what sort of sharing or other adjustments would need to be made to fairly divide that cost between the shareholders and the ratepayers.

It will be, I believe, more complicated if we are going to have some sort of sharing or disallowance of costs, that it's more complicated to do that with a run rate. Probably not impossible, but it's more complicated, and I think in that case you would almost certainly have to have some sort of true-up -- tracking and true-up mechanism to make sure that the customers and the shareholders came out where the Commission wanted them to come out.

Q. Okay. And you stated at the beginning of your answer that you felt like the Public Staff would be opposed to the run rate, and I've heard the reason for the complications that would make the whole process more complicated from the aspect of this equitable sharing, but are there other concerns or challenges besides that one challenge?

A. Well, I think also, and maybe you may have meant to include this in sort of that universe of equitable sharing, but also from the perspective of what the Commission did in the Dominion case. If that was the way the Commission went in the Duke cases and after all the appeals, I think you would have the same sort of complications.

Other than that, sitting here today, I think the main complication, once everything has been settled, other than what I've spoken to before, is you'd need to decide whether to have a tracking mechanism, a true-up, what sort of carrying costs, if any, would be allowed, what sort of return on refunds, true-up refunds to the customers would be set in place. None of those, I think, are insurmountable, but they are issues that the Commission and the intervenors would have to deal with.

A. (Charles Junis) Commissioner, if I could just add. A complication would be -- and Mr. Maness has kind of hit on it with the possible true-up -- is the review of those cost expenditures and that, while these are identified as expenses, this is not a repetitive incurrence of the same cost year after year like you would think of as testing or sludge hauling. This is a group -- a complex grouping of costs tied to excavation, corrective action, liners, landfills.

I mean, there are so many different costs grouped into this ARO, an opportunity to review not only that the actions but also the costs are prudently incurred, that's where I think Mr. Maness was hitting on with the true-up, that that would be a necessary part of a potential run rate, which I don't think either party has appropriately addressed in this proceeding as opposed to the previous rate cases.

Q. Okay. Thank you, Mr. Junis.

And, Mr. Maness, could you quickly put your hands on -- Duke filed a late-filed exhibit on September 2nd of this year.

A. (Michael C. Maness) I might have to ask for help from counsel as to where to find that on our server.

Q. Might be easiest just to go to the docket. Or the --

A. You're right. All right. I'll pull it up that way.

(Witness peruses document.)

Q. And it was filed September 2nd.

A. All right. Hang on just a minute.

(Witness peruses document.)

In this case?

Q. Correct.

A. (Witness peruses document.)

All right. Late-filed Exhibit Number 1?

Q. Correct. And so this is a late-filed exhibit that DEC provided regarding the impact on the Company's credit metrics when various hypothetical scenarios are put upon them, correct?

A. Yes.

Q. Have you had a chance to look at this late-filed exhibit?

A. I have reviewed it very generally. Not in any detail.

Q. Okay. If you could --

A. It probably -- it would be something that Mr. Hinton would probably pay more attention to than I would in the normal course of our division of labor.

Q. Okay. So if you could go to the last page.

A. Yes.

Q. And so my question is with respect to the last two lines. In the third to the last line, it says:

"Approximate average retail rate impact."

Do you see that on the left-hand side?

A. Yes.

Q. Third full column. And it has for DEC and DEP. And then across the top there are five different scenarios. The first is the existing, as Mr. Mehta called it, spend, defer, and recover mechanism.

A. Yes.

Q. And it looks like the impact to the customer -- or sorry, retail rate impact is 2 percent for DEC and 3 percent for DEP.

A. I see that, yes.

Q. And then it goes across. So my -- and do you see with the second scenario there's a run rate component, and that third scenario is a run rate component. And you see how those rate impacts -- retail rate impacts pretty much double. And then the very last scenario is the Dominion scenario where the -- there's a 10-year no return, and you see the rate impacts there.

So I'm asking this of the Public Staff. You represent the using and consuming public. And I guess you said there was some benefit to allowing these rates to be part of ongoing payment versus a deferred scenario. But in looking at these, how do you feel about which scenario seems to -- that the Public Staff -- understand your scenario is not on here, but the scenario that works best for the using and consuming public?

A. Well, I'm assuming that what we're seeing here is that 5.1, and, 6.0, and 5.0, and 6.1 is -- and I don't know what -- one of the things that was interesting about this was there seemed to be some sort of counterintuitive impacts on credit from having a run rate, and I don't know what -- well, there it is. I see that.

Q. Right. It's the -- but it looks like the credit metrics remain above the downgrade threshold for each of them --

A. Right.

Q. -- except for scenario number 5.

A. Okay. I just wasn't sure whether it took into account any impacts on cost of debt or equity in that -- those average retail rate impacts. So I'm assuming, from what I see here -- and I haven't dug into these numbers at all -- is that you're seeing the year-one impact when -- and in the early years, you would have somewhat what we would call a doubling up of both the amortization of what had been spent before, and then the attempt to recover in current rates on a more contemporaneous basis the costs as they were being incurred over time.

So I'm getting just some general almost speculation here, but I would expect that after a few years, let's say five years, you would have a drop so that you'd no longer be picking up amortization of costs before 2020, but you would just begin doing the run rate with hopefully a smaller true-up each year.

And then the other benefit is that you'd be done with it sooner. You wouldn't have a five-year run-out after the last year of amortizing the last one or two years of cost, you would just hopefully recover it in the last year that the monies were expended and then have a very -- hopefully a very small true-up to be amortized.

So there's benefits. There's a higher cost of switching in these early years and then a lower cost in the later years. So that's the benefit, and I think it's a benefit to the Company for the most part. To the customers, I guess, in a general sense, they would rather have the recovery stretched out further. But then you also -- if the Commission isn't going to disallow any sort of return, you're going to have additional return that's going to be built in to stretching that out further, so --

Q. And what -- sorry to interrupt. Please continue.

A. So I think there's pluses and minuses. It's probably -- that switch is going to cause an impact. Unless you somehow sort of phase it in, it's going to cause a pretty significant impact in the first four or five years, which then should level out at a lower number over time.

Q. And let's assume a perfect scenario that we did know the exact costs. From a Public Staff position, is it more beneficial -- and let's assume that the Commission would grant a return on the unamortized balance.

Is it more beneficial to the customer to have a run rate where it could be higher up front, or is it more beneficial to the customer -- it's kind of a 15-year mortgage versus a 30-year mortgage. From a Public Staff perspective, which do you find is more beneficial to the customer; to pay a return and stretch out these large costs over a period of time, or to put these costs in as an expense and, as you said, get through them more quickly?

A. I think that's -- and again, it's sort of a multilayered question and answer. To the extent that you're only looking at what would provide the lowest rates to the customers stretching it out, at least at first glance would provide for lower rates for a period of time. But if you stretch things out too far, then you may impact the Company's credit ratings to a certain extent, or the metrics at least to -- it might cause some unexpected effects down the road if you have too many regulatory assets on the books that are being put off, and put off, and put off.

If you're talking about a longer base amortization period, let's say something like the Public Staff is proposing but even with a return, then the -- that 5.1, 6.0 percent impact is not going to be quite as large, and it's more comfortable to me to talk about a transition to some sort of run rate. If you're talking about a five-year amortization period, it's not so comfortable, because then you are -- the shorter you make that amortization period, the higher this 5.1, 6.0 percent is going to be.

Q. Okay. Thank you. And did you have anything else you wanted to add, benefits or concerns regarding a potential run rate?

A. Not that I can think of here at the minute.

Q. Okay.

A. Excuse me.

Q. So if we could move to -- let's just go to your testimony summary, page 4.

A. (Witness peruses document.)

Okay.

Q. Okay. So on page 4, you state:

"The automatic right to defer capital costs associated with these non-ARO projects should not continue."

And you continue and you say -- and if you could help me understand, you say that:

"The non-ARO-related deferral requested in this case is more similar in nature to other requests that have been brought forth frequently in the past related to new generation projects."

And my questions are, which request are you referring to? And what costs were being sought to be deferred? And did the Commission grant these deferral requests?

A. So you're saying which requests -- you're referring to what I refer to other generation projects?

Q. Correct.

A. In the past.

Q. Right. You're saying that these non-ARO costs are more similar to that type of deferral request that you've seen in the recent past related to other generation projects. So which -- I'm just trying to figure out which projects, which deferral requests are you speaking of? And what were the costs that were sought to be deferred? And what's the Commission's decision?

A. I don't have a list in front of me. I know -- I believe, with regard to Duke, the most recent one may have been the Lee combined-cycle plant. But these are fairly frequent, when the Commission comes in for rate cases, that they'll have a plant that's going into service a few months before the rate case -- rates are going into effect, and they will request that the capital costs, meaning the depreciation return on investment between the date that the plant goes into service and the date that the rates go into effect, that they be allowed to defer those and then amortize them over some period after the rates have gone into effect.

Q. Correct. And usually those are granted by the Commission, correct?

A. They are. Sometimes the Public Staff and the Company or another intervenor in the Company might have concerns about the amount of costs. There may be particular items where we may raise concerns, sometimes to the Commission, sometimes just internally about should this be included, should this not be included.

There have been a few cases in the past where the Public Staff has opposed deferral altogether because we didn't think that the magnitude rose to the level which would justify deferral. I believe in the case that I'm thinking about, which was a Duke case, the Commission disagreed with us and allowed the deferral over our objection.

So I would say, except for that when there -- a lot of times we may be nibbling around the edges to try to settle what should be included and what should not be included, but generally, I think the Commission has a history of approving those.

I'm thinking there was one back several years ago regarding a Dominion plant where the plant had really gone into service quite a bit of time before the rate case came about. And I'm struggling to remember the outcome of that. I can't remember if the Commission allowed it or not, but then they tried to put some boundary lines around when these types of things -- deferral requests would be acceptable and when they would not.

There was one case in which we opposed, but then based on, I believe, the Commission order, we came back. Or actually it was based on data that we had misinterpreted from the Company, we came back in, supplemental testimony, and agreed with the deferral.

Q. I think that was Warren County?

A. It may have been. That sounds like it may have been it, yes.

Q. So I'm just trying to seek your position here. And what I think I've heard is the effect -- with it -- hypothetically, let's assume that most cases the Commission does allow for this deferral. Clearly, both mechanisms lead to the same result, but what I heard you state in your testimony is that Public Staff would like just like the option to be able to oppose this type of deferral; is that a correct assumption, or are you saying something else?

A. I think that is generally the correct assumption. As I state more completely in one of my testimonies, whether it was the initial or supplemental that's summarized here, the Public Staff was a bit surprised when, in this case for the first time, DEC proposed deferral and amortization of these types of cost, which were not ARO related but were related to facilities being constructed to deal with the ongoing production ash.

When we read the terms of the Commission's order -- the Company's request and the Commission's order in Sub 1110, we -- and the 1146 rate case -- we felt like that they were within the bounds of the Commission's order. And so we didn't oppose it in this case. But we would like action by the Commission to say that non-ARO projects should, in the future, be considered like other generation and deferral requests where it wouldn't be automatically covered by the Commission's order in Sub 1110 and 1146.

COMMISSIONER DUFFLEY: Okay. And that is all of the questions that I have. I will give you, Public Staff, the opportunity to file a late-filed exhibit. I don't need to see all of the cases like Warren County where that deferral was granted by the Commission, but if there are any cases out there where the Commission did not allow for the deferral of those types of expenses, feel free to submit those as a late-filed exhibit.

Thank you, Chair Mitchell. Thank you, gentlemen.

THE WITNESS: If I could just clarify, Commissioner Duffley, that would be cases where the Commission disallowed the request for deferral in its entirety?

COMMISSIONER DUFFLEY: No. Well, it would be the cases to which you were referring as support to your position that these non-ARO costs are similar to requests that have been brought forth frequently related to new generation projects.

THE WITNESS: Okay. So it would be all of the cases, not just the ones -- I misunderstood. And thought you were just asking about ones that the Commission had disallowed. But you're saying you'd sort of like to see all of the --

COMMISSIONER DUFFLEY: No, you did hear me correctly. I don't need to see the ones where the Commission granted the deferral.

THE WITNESS: Okay. All right.

CHAIR MITCHELL: All right. Anything further, Commissioner Duffley?

COMMISSIONER DUFFLEY: No, Chair Mitchell. Thank you, gentlemen.

CHAIR MITCHELL: All right. Commissioner Hughes?

COMMISSIONER HUGHES: No additional questions. Thanks.

CHAIR MITCHELL: Okay. And Commissioner McKissick?

COMMISSIONER McKISSICK: Just one or two questions, Madam Chair.

EXAMINATION BY COMMISSIONER McKISSICK:

Q. First I want to thank the witnesses for providing such insightful testimony. I think so many of the questions that were in my mind already may have been asked and answered. And so it leaves me with very little to really try to get some clarity on.

But I guess one issue I'm still wrestling with somewhat is the equitable sharing and trying to understand exactly when -- what the standards would be for culpability. I mean, we know what the standards are for imprudence, and we understand why in this case there would not be grounds for finding imprudence.

But in terms of culpability, what I'm looking for is what could be articulated as a standard that applies not simply to the facts of this case, but to other cases that the Commission might consider if they're going down the path of equitable sharing. And I understand that there's the nuclear power plant issues that were out there, and things of that sort, and other projects that have been large that, you know, there was a basis for the Commission to take some action employing a similar kind of concept.

But can the two of you help me articulate what this standard should be in clear, concise terms which are applicable on a broad-base basis, not just based on the facts of this case in terms of what was known or reasonably should have been known, and what actions they might have failed to have taken, you know, in terms of environmental measures to mitigate things somewhere many, many decades ago? That's it.

A. (Charles Junis) Mr. Maness, do you want to start or me?

A. (Michael C. Maness) Well, I was going to say, if you're specifically talking about culpability, it probably does start with you. If we're talking more generally about sharing, it would probably start with those cases in the early '80s, in 1983 forward where the Commission first, to my knowledge, started discussing an equitable sharing of those abandonment costs. Those did not involve the concept of culpability.

A. (Charles Junis) And, Commissioner McKissick, if I understand, your question is geared towards culpability; is that correct?

Q. Correct. Because I gather here there has been discussion about there being culpability, that Duke did not intervene at an appropriate time knowing that information was out there in dealing with the impoundment facilities for coal ash, and that they did not take appropriate measures. There were the exceedances that were out there; there was the reports that were being done; there were measures that were out there that it really would have, you know, informed them that they needed to do something other than what they did. Okay?

So, I mean, I understand what it looks like here in terms of what you're arguing, but when you start using a term like "culpability," which is broad and rather expansive, I'd like to know that it's more than just a subjective feeling that could be arbitrary based upon the way you see and feel it.

So help me try to put my arms around what that term -- what are the standards, A, B, C, and D? I mean, we know what they are for imprudence; we've got A, B, C, and D. What are they for culpability? If that's a concept that we're embracing more than just the concept of equitable sharing. But that's what's being contented here; is that not correct?

A. Correct. So you have a kind of baseline sharing that Mr. Maness covered dealing with the magnitude of the costs, and then you have kind of further adjustment, this qualitative adjustment based on culpability. And this may require some refinement, but on the spot here, I think the true key is that there were environmental regulations in place. The Company violated those regulations.

And with that, they were going to incur costs tied to these impoundments to correct this issue. That there were already in place corrective-action measures required by 2L. There were already regulations in place that did not allow the unpermitted discharge of wastewater. Those impacts, tied to that noncompliance, drives up costs. And like I said, would have required some corrective action or remediation. And now you have this overlap with these new laws and regulations regarding the actual closure of these impoundments. And that's where this becomes complicated. And we've talked about impossible or speculative. That you have kind of precluded a traditional imprudence analysis because this covers such a long period of time. And that you cannot reasonably create an alternative or feasible alternative throughout this period of time.

You would have to materialize so much information and create all sorts of -- and you can't create one path. There are tens if not hundreds of thousands of paths, because you have multiple sites, different corrective actions, different storage options, and at what point in time determines how much ash is in each of those impoundments or storage units.

So the possibilities are endless, and that's what really complicates this. And so if you had to boil it down, okay, is there -- and maybe this is even still too suited to this case, but was there an environmental or regulatory requirement in place over this period of time; has it been shown that they did not adhere to that requirement; and does that significantly impact the costs that are being sought for recovery today; and would there have been an alternative route of actions that could have been taken in the past that would change the costs incurred today?

Now, I recognize that, if they had done something differently in the past, there would have been costs associated with that and recovery of those costs through rates. But you would also recognize that those costs would be either mostly or entirely recovered already to this point and tied to customers that actually benefitted from that electric generation. And that's another disconnect in this case, that a majority of these costs are tied to previous customers that will be fielded by present and future customers.

Does that help? And we can kind of go back and forth if this requires some further refinement, or maybe we're given an opportunity to provide a late-filed exhibit to maybe lay this out more succinctly.

A. (Michael C. Maness) If I could --

Q. Sure, go ahead.

A. -- add a little bit of that. I think also, in addition to what Mr. Junis said with regard to some of these costs would have been already in rates, already been recovered from the correct customers, that's certainly true. But I think you also have to recognize that, so to speak, the chickens are coming home to roost now. That these costs are going to be incurred now, and they're the result of actions or inactions in the past that we can't -- as Mr. Junis says, we can't describe the alternative path, but we can certainly see where exorbitant costs are being charged to the customers now or requested to be charged.

Q. Well, I appreciate those thoughts. Perhaps if there could be a late-filed exhibit that provides as much clarity and specificity as possible that, you know, establishes kind of a bright line not just for the facts of this case. And I understand it may well be that you're -- we have whether there's, you know, regulations that existed that were violated and, you know, going into all the details as to what could or could not have been done. I guess I'm just trying to analyze this as objectively as I can based upon the facts that are not only applicable to this particular case but to what we, as a Commission, might do moving forward in the future, or with equitable sharing as what should be done as recommended by the Public Staff.

COMMISSIONER McKISSICK: Thank you, Madam Chair, I don't have any further questions. I think you guys did a great job over the last two days. It's been very helpful and insightful. And I think Commissioner Brown-Bland clearly earlier asked you a number of questions that were in the back of my mind, so I look forward to reviewing that late-filed exhibit. Thank you.

THE WITNESS: (Charles Junis) Thank you, sir.

MR. MEHTA: Chair Mitchell, before we get to questions on Commissioner questions, may I just follow up with Commission McKissick on his late-filed exhibit request? To the extent that the Public Staff takes him up and makes a late-filed exhibit, the Company would like the opportunity, Commissioner McKissick, to respond to that particular filing to the extent that we feel it necessary. And if that is acceptable, we will certainly do so.

CHAIR MITCHELL: Commissioner McKissick's on mute, but I will go ahead and respond as I believe he did, which is that would be acceptable, Mr. Mehta.

MR. MEHTA: Thank you, Madam Chair.

CHAIR MITCHELL: And I actually have a question for Mr. Maness. I'm going to request an exhibit of you, of the Public Staff, and, Mr. Mehta, I'm going to make the same request of the Company and encourage you-all to work together in developing this exhibit if it is possible and it saves everyone some time and effort.

But, Mr. Maness, you have testified today about the accounting treatment for the ARO-related coal ash associated costs, and it would be helpful for the Commission and for the Commission staff to see an exhibit that shows the various journal entries associated with the accounting -- the accounting that you have described today. We don't need to see actual dollar amounts, but rather, just sort of an illustration of how these -- how the entries have been made. An example -- just to be a little bit clearer, an example that shows the debits and credits to the applicable FERC accounts from the original recordation of the ARO to the ultimate recovery of these amounts.

Let me know if you have any questions about what I've asked for. And again, I will make the same request of the Company. So to the extent that it makes sense for y'all to work together on that, please do so.

THE WITNESS: (Michael C. Maness) I think it does, Madam Chair. I think that does make sense. We have gotten some information from the Company of this during discovery, and I'm confident we could get together and provide that.

CHAIR MITCHELL: Okay. All right. Thank you very much, Mr. Maness.

MR. MEHTA: I concur with Mr. Maness, Chair Mitchell, I'm sure we can work together on that.

CHAIR MITCHELL: Okay. Thank Mr. Mehta. All right. We will now -- we will turn to questions on the Commissioners' questions. Questions from any of the -- from any of the intervenors?

(No response.)

CHAIR MITCHELL: All right. Questions from Duke?

MR. MEHTA: No questions.

CHAIR MITCHELL: Okay. Any questions from the Public Staff on Commissioners' questions?

MR. GRANTMYRE: No questions from Grantmyre.

MS. LUHR: No questions for me.

CHAIR MITCHELL: All right. At this point the in time, witnesses may step down. I will entertain motions from counsel.

MR. MEHTA: Chair Mitchell, for Duke Energy Carolinas, I would move the admission into evidence of DEC Junis/Maness Cross Examination Exhibits 1 through 5.

CHAIR MITCHELL: All right. Mr. Mehta, hearing no objection to your motion, it is allowed.

(DEC Junis/Maness Cross Examination Exhibits 1 through 5 were admitted into evidence.)

MS. LUHR: And, Chair Mitchell, the Public Staff would move that the exhibit attached to the prefiled testimony of witness Junis be entered into the record and marked for identification as premarked; and that Public Staff Junis/Maness Redirect Exhibit Number 1 be entered into the record as marked during this proceeding.

CHAIR MITCHELL: All right. Ms. Luhr, hearing no objection to the motion, your motion will be allowed.

(Public Staff Junis Exhibits 1, 3 through 18, and 20; Public Staff Junis Confidential Exhibit 19; Public Staff Junis Corrected Exhibit 2; and Public Staff Junis/Maness Redirect Exhibit 1 were admitted into evidence.)

MR. GRANTMYRE: Chair Mitchell, this is William Grantmyre with the Public Staff, we'd move that the exhibits attached to the prefiled third supplemental testimony of witness Maness be entered into the record and marked for identification as premarked. That is Maness Exhibits 1 and 2. All his previous testimonies, it's my understanding, and exhibits have already been entered into the record as evidence.

CHAIR MITCHELL: You are correct, Mr. Grantmyre, and I will allow your motion having heard no objection to it.

(Public Staff Maness Direct Exhibits I and II, Public Staff Maness Exhibit III, Public Staff Maness Exhibit I Revised and Exhibit II Revised, and Public Staff Maness Second Revised and Second Stipulation Exhibits I and II were admitted into evidence.)

CHAIR MITCHELL: All right. Gentlemen, you may step down. We appreciate your testimony this afternoon.

Ms. Downey, we have another housekeeping matter to attend to. Ms. Downey, where are you? Let's see, I've lost you, Ms. Downey.

MS. DOWNEY: Here I am, Chair Mitchell.

CHAIR MITCHELL: Okay.

MS. DOWNEY: So is this the appropriate time to move in the testimony of Mr. Metz and Mr. Thomas?

CHAIR MITCHELL: All right. Let's -- yes, please do.

MS. DOWNEY: Chair Mitchell, I move that the second supplemental testimony of Dustin R. Metz filed September 8, 2020, consisting of six pages and appendix A, be entered into evidence.

CHAIR MITCHELL: All right. Hearing no objection, Ms. Downey, the motion is allowed.

(Whereupon, the prefiled second supplemental testimony and Appendix A of Dustin R. Metz was copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1187

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

SECOND SUPPLEMENTAL TESTIMONY OF DUSTIN R. METZ ON BEHALF OF THE PUBLIC STAFF NORTH CAROLINA UTILITIES COMMISSION

SEPTEMBER 8, 2020

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is Dustin Ray Metz. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am an Engineer with the Electric Division of the Public Staff – North Carolina Utilities Commission.

Q. ARE YOU THE SAME DUSTIN METZ WHO FILED TESTIMONY IN THIS DOCKET ON FEBRUARY 18, 2020, AND MARCH 23, 2020?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide to the Commission the results of my investigation into certain plant-related capital costs included in Duke Energy Carolinas LLC's (DEC or the Company) second supplemental direct testimony filed on July 2, 2020 for the purpose of updating certain known and measurable changes to rate base through May 31, 2020 (May 2020 Update) in Docket No. E-7, Sub 1214.

Q. PLEASE SUMMARIZE YOUR ADDITIONAL SUPPLEMENTAL TESTIMONY.

A. As a result of my investigation, I recommend that the capital costs associated with the Lincoln County Combustion Turbine 17 (LCCT 17) project be removed from rate base at this time. In addition, I recommend that the capital costs associated with Project Focal Point also be removed from rate base.

Q. PLEASE EXPLAIN WHY YOU ARE RECOMMENDING REMOVAL OF THE LCCT 17 PROJECT COSTS AT THIS TIME.

A. The Commission's order approving the LCCT 17 CPCN in Docket No. E-7, Sub 1134 on December 7, 2017 states in part:

> That the Application filed in this docket should be, and the same hereby is, approved and a Certificate of Public Convenience and Necessity for the nominal 402 MW Lincoln County CT Project and associated transmission lines is hereby granted with the condition that DEC will not seek cost recovery before the later of December 1, 2024, or the date by which DEC has taken care, custody and control and placed

> the unit into commercial operation, and this Order shall constitute the certificate;[1]

The plain language of the order, that no costs of the LCCT 17 and associated transmission lines should be included for rate recovery prior to December 1, 2024, is unambiguous. Based on the responses to data requests and discussions with Company personnel, I found that DEC included certain costs associated with the support and operation of LCCT 17 in rate base in the May 2020 Update. It is my understanding that the Company agrees that, pursuant to the Commission's Sub 1134 Order, these costs should not have been included in rate base at this time.

Q. WHAT IS THE AMOUNT THAT YOU ARE RECOMMENDING FOR LCCT 17 DISALLOWANCE?

A. I recommend that $14,295,381.65 (system) be removed from rate base at this time. Once the project meets the conditions set forth in the Commission's Sub 1134 order, the project cost(s) may be properly included in any general rate case request for cost recovery at that time. However, I take no position regarding the reasonableness and prudence of any of these costs at this time. I have provided this adjustment to Public Staff witness Boswell.

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[1] *Order Issuing Certificate of Public Convenience and Necessity with Conditions* in Docket No. E-7, Sub 1134, ordering paragraph 1, at 43.

Q. WHAT IS PROJECT FOCAL POINT?

A. This project is a corporate-wide initiative to replace and upgrade older monitoring and recording equipment (e.g., cameras) with modern, state of the art equipment. This project, once completed, is intended to be an overall upgrade to Duke Energy Corporation's security system.

Q. WHY YOU ARE RECOMMENDING COST DISALLOWANCE OF THIS PROJECT?

A. The May 2020 Update costs for Project Focal Point included in rate base in this proceeding are largely for the purchase of equipment that has yet to be fully installed and operational. After discussions with the Company on this particular project, the Company is agreeable to not seek cost recovery of this project in this rate case.

Q. WHAT AMOUNT OF PROJECT FOCAL POINT ARE YOU RECOMMENDING FOR DISALLOWANCE IN THIS CASE?

A. I recommend that $3,715,121.40 (system) be removed at this time. Once the project and any subparts of the project are successfully installed, tested, commissioned and working per their designed state, the Company may seek cost recovery at that time. The reasonableness and prudence of the project will be reviewed in more detail at that time. I have provided this adjustment to Public Staff witness Boswell for incorporation in her exhibits and schedules.

Q. MR. METZ, HAVE YOU REVIEWED THE BASE FUEL FACTOR AS IT APPLIES TO THIS CASE AND DO YOU HAVE ANY RECOMMENDATIONS?

A. Yes, I have reviewed the base fuel factor. Under the Second Agreement and Stipulation of Partial Settlement between the Company and the Public Staff, filed July 31, 2020, the parties agreed that should a Commission order be issued in the fuel rider proceeding in Docket No, E-7, Sub 1228 (Sub 1228) prior to the date the proposed orders are due in this general rate case proceeding, the total of the approved base fuel and fuel related cost factors, by customer class, will be the sum of the respective base fuel and fuel related cost factors set in Docket No. E-7, Sub 1146 and the annual non-EMF fuel and fuel related cost riders approved by the Commission in Sub 1228. On August 19, 2020, the Commission approved new fuel and fuel related cost riders in the Sub 1228 proceeding; accordingly, I have calculated the updated fuel and fuel related cost factors to be utilized in this proceeding. I have provided this recommendation to Public Staff witnesses Boswell for incorporation in her schedules and exhibits.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

DUSTIN R. METZ

Through the Commonwealth of Virginia Board of Contractors, I hold a current Tradesman License certification of Journeyman and Master within the electrical trade, awarded in 2008 and 2009 respectively. I graduated from Central Virginia Community College, receiving Associate of Applied Science degrees in Electronics and Electrical Technology (Magna Cum Laude) in 2011 and 2012 respectively, and an Associate of Arts in Science in General Studies (Cum Laude) in 2013. I graduated from Old Dominion University in 2014, earning a Bachelor of Science degree in Engineering Technology with a major in Electrical Engineering and a minor in Engineering Management.

I have over twelve years of combined experience in engineering, electromechanical system design, troubleshooting, repair, installation, commissioning of electrical and electronic control systems in industrial and commercial nuclear facilities, project planning and management, and general construction experience. My general construction experience includes six years of employment with Framatome, where I provided onsite technical support, craft oversight, and engineer design change packages, as well as participated in root cause analysis teams at commercial nuclear power plants, including plants owned by both Duke and Dominion and an additional six years of employment with an industrial and commercial construction company, where I provided field fabrication and installation of electrical components that ranged from low voltage controls to medium voltage equipment, project planning and coordination with multiple work groups, craft oversight, and safety inspections.

I joined the Public Staff in the fall of 2015. Since that time, I have worked on general rate cases, fuel cases, applications for certificates of public convenience and necessity, service and power quality, customer complaints, North American Electric Reliability Corporation (NERC) Reliability Standards, nuclear decommissioning, National Electric Safety Code (NESC) Subcommittee 3 (Electric Supply Stations), avoided costs and PURPA, interconnection procedures, integrated resource planning, and power plant performance evaluations. I have also participated in multiple technical working groups and been involved in other aspects of utility regulation.

MS. DOWNEY: And I would also move that the supplemental testimony of Jeff T. Thomas filed September 8, 2020, consisting of 10 pages, be entered into evidence.

CHAIR MITCHELL: All right. Ms. Downey, hearing no objection to that motion, it is allowed as well.

MS. DOWNEY: Thank you.

(Whereupon, the prefiled supplemental testimony of Jeff T. Thomas was copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUBS 1187, 1213 AND 1214

Supplemental Testimony of Jeff T. Thomas

On Behalf of the Public Staff

North Carolina Utilities Commission

September 8, 2020

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A. My name is Jeff Thomas. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am an Engineer with the Energy Division of the Public Staff – North Carolina Utilities Commission.

Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN THESE PROCEEDINGS?

A. Yes.

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY IN THIS PROCEEDING.

A. The purpose of my supplemental testimony is to summarize the Public Staff's investigation into Duke Energy Carolinas, LLC's

("DEC") Second Supplemental Direct Testimony and Exhibits of Jane L. McManeus and Second Supplemental Direct Testimony of Michael J. Pirro, filed on July 2, 2020 ("May Update"). My testimony specifically addresses the Public Staff's investigation into transmission and distribution ("T&D") assets placed in service from February 1, 2020 through May 31, 2020 for DEC ("Update Period").

Q. PLEASE SUMMARIZE THE ASSETS PLACED INTO SERVICE DURING THE UPDATE PERIOD.

A. As seen in the table below, during the Update Period DEC placed $405.6 million into rate base in T&D investments. These investments constitute a wide variety of investments, including traditional T&D expenditures, those related to the Grid Improvement Plan ("GIP"), and some related to the Smart Grid Technology Plan ("SGTP"). DEC has identified approximately $34.7 million in GIP related investments during the Update Period.[1]

[1] This only captures GIP related spend for projects greater than $500 thousand. The actual amount of GIP spend may be slightly higher.

Table 1: T&D Assets Placed in Service, North and South Carolina (millions of dollars).

Source: DEC DR 6 (6th Supplemental)

	Transmission	**Distribution**	**Total**
DEC (February 2020 through May 2020)	127.8	277.8	**405.6**
GIP Related (projects > $500k)	10.5	24.2	**34.7**

Q. PLEASE SUMMARIZE THE SCOPE OF YOUR INVESTIGATION.

A. The Public Staff audited numerous DEC T&D projects. The audit covered approximately 64% of DEC's total transmission investment and 12% of DEC's total distribution investment for the Update Period. During the course of our investigation, we requested project management documentation, work breakdown structures with all project expenditures, cost variance reports, status of GIP related projects, requests and presentations to DEC boards, and other pertinent information.[2] The Public Staff reviewed this information and held multiple conference calls with DEC in order to determine if the investments included in rate base in the May Update were reasonable and prudently incurred.

[2] The level of detail associated with each project depends on the total budgeted project spend. Generally, smaller projects have less documentation and require fewer company approvals than larger projects.

Q. WHAT DID THE RESULTS OF YOUR INVESTIGATION SHOW?

A. During the Update Period, DEC closed to rate base SOG Segmentation and Automation projects of approximately $7.1 million.[3] This project is a "blanket project" that tracks related expenses without a specific start or end date. This practice is common for projects such as SOG, which are comprised of many smaller projects that are rapidly completed.

During discovery, the Public Staff found that the $7.1 million represents SOG Segmentation and Automation projects that DEC closed to plant on 58 distribution circuits. Out of the 58 circuits, SOG is fully enabled on two circuits, or 3.5% of the total. Thirteen circuits (22%) are slated for SOG enablement in 2020, and 43 circuits (74%) are not expected to be fully enabled until 2021 or 2022.[4]

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[3] Project ID SGSELFND represents the North Carolina distribution portion. Project ID SGSELFSD was also closed to plant for approximately $1.7 M, representing the South Carolina distribution portion.

[4] DEC indicated that the schedule provided during discovery was conservative, and that they hope to be able to complete some circuits early.

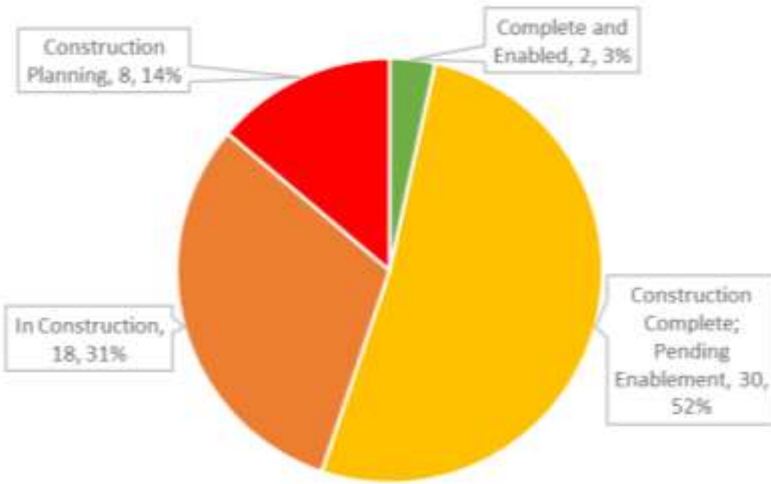


Figure 1: Status of SOG Circuits closed to plant in Update Period (# of circuits, % of circuits

Q. CAN YOU EXPLAIN WHAT YOU MEAN BY FULLY 'ENABLED'?

A. Yes. In order for a circuit to be fully "enabled" for SOG, DEC must first undertake several steps referred to as "SOG construction": (1) segment the circuit into sections so any faults can be isolated; (2) tie the circuit to a second, backup circuit; and (3) ensure each circuit and substation has sufficient capacity to supply both circuits' designed SOG load.[5]

Once these steps are completed, the interconnected circuits and SOG devices must be programmed into the Advanced Distribution Management System software to enable automatic responses to faults. In all cases, SOG circuits are enabled in "teams" – two or more

[5] The Company SOG standard for a pair circuits seeks to allow the first SOG circuit to pick up 70% of the second SOG circuit's peak load during 90% of the time.

circuits that are tied together to provide the segmentation and backfeed abilities that are necessary for SOG to function.

Q. ONCE ENABLED, HOW DOES SOG OPERATE?

A. In the event of a circuit segment fault: (1) the enabled SOG equipment isolates that circuit segment; (2) the substation continues to feed the circuit segments between the fault and the substation; and (3) the backup circuit begins feeding the circuit segments between the fault and the backup circuit. Thus, only the circuit segment with the fault experiences a sustained outage. In a SOG enabled circuit, all of these steps happen automatically, without human intervention, and typically take 2-3 minutes to resolve.

Q. CAN YOU EXPLAIN WHY SOME CIRCUITS ARE NOT YET FULLY ENABLED?

A. DEC has explained the concept of circuit enablement and noted that the highly trained personnel who can operate the software designed to locate, isolate, and restore faults during a SOG event can only program so many circuits at a time. The circuits and SOG devices are programmed into software that is specific to fault location, isolation, and restoration activities.[6] Prior to this year, DEC stated that SOG investments have been proceeding at a manageable pace;

[6] The software used by DEC is called Yukon Feeder Automation software and is separate from DEC's normal operational software.

however, as the number of circuits targeted for SOG has increased, the demand for the highly skilled personnel has increased. This has led to delays in enabling SOG circuits after construction is complete.

Q. IF THESE SOG CIRCUIT INVESTMENTS ARE NOT FULLY ENABLED AT THIS TIME, ARE THEY STILL CONSIDERED USED AND USEFUL?

A. Based on a discussion with the Public Staff Accounting Division, and advice of counsel, I believe these SOG circuits meet the technical and legal definitions of plant in service and thus I do not recommend any revenue adjustments. These SOG circuits are used and useful in providing utility service, even though most are not fully enabled and producing the full benefits as described by DEC witness Oliver in his testimony in this proceeding.

Q. ARE THE PARTIALLY ENABLED SOG CIRCUITS PROVIDING ANY BENEFITS TO CUSTOMERS AT THIS TIME?

A. There are some potential benefits associated with partially enabled SOG circuits. If a SOG team has completed construction but the circuits are not enabled, the fault isolation process described above can still happen, albeit manually. Human operators in DEC's distribution control center can manually segment and backfeed the faulted circuit; but the manual process is slower and produces fewer reliability benefits when contrasted with the rapid and automatic operation of SOG equipment. Realizing these partial benefits is contingent upon DEC implementing a protocol to manually operate the SOG circuits prior to full enablement. The full benefits will be delayed until completion of the full SOG construction and programming steps discussed earlier in my testimony.

Q. DO YOU HAVE ANY OTHER COMMENTS BASED ON YOUR INVESTIGATION?

A. Yes. As evidenced in my earlier testimony, it is apparent that traditional concepts of "used and useful" do not fully account for all the issues that must be considered when evaluating GIP investments and programs. The complexity with which different GIP programs, software, and physical devices interact means that "full functionality" may not neatly match up with "used and useful."[7] This is especially true given the scale and pace of T&D investments envisioned under DEC's GIP.

This potential timing mismatch underscores the importance of completing GIP projects promptly, with as little delay as possible, so that benefits can be tracked and reported pursuant to the terms of the Settlement, if approved by the Commission. It will be more

[7] Advanced Metering Infrastructure (AMI meters) is a good example of this principle. While AMI meters may be used and useful in recording and transmitting electricity consumption, the lack of software or programs on the back end means ratepayers may not immediately enjoy the full benefits of a technology at the time it goes into rate base.

challenging to assess the cost effectiveness of GIP-related projects, and adjust the overall course of the GIP, in an ongoing manner if customers may not begin realizing the benefits of today's rate based investments for a year or more. Nevertheless, DEC should be careful to balance the incremental costs associated with expedited project completion against the overall value to customers.

The challenges of reviewing the costs and benefits of certain GIP programs and investments also highlights the importance of detailed and transparent reporting and review of the GIP.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CHAIR MITCHELL: All right. Thank you, Ms. Downey.

All right. Ms. Holt, you may -- before we get to the next witness, any additional procedural matters for my consideration before we proceed?

(No response.)

CHAIR MITCHELL: All right. Hearing none, Ms. Holt, you may call your witness.

MS. HOLT: Thank you. The Public Staff calls Michelle Boswell.

CHAIR MITCHELL: All right.

Ms. Boswell, let's see, there you are.

Whereupon,

MICHELLE M. BOSWELL,

having first been duly affirmed, was examined and testified as follows:

CHAIR MITCHELL: All right. Ms. Holt, you may proceed.

DIRECT EXAMINATION BY MS. HOLT:

Q. Please state your name, position, and business address for the record.

A. Michelle Boswell, 430 North Salisbury Street, Raleigh, North Carolina. I am the accounting manager with the accounting division, electric section.

Q. Ms. Boswell, you provided testimony regarding excess deferred income taxes in the Duke Energy Carolinas and Duke Energy Progress consolidated hearing; did you not?

A. I did.

Q. Since that testimony, on September 8, 2020, did you prefile second supplemental and settlement testimony consisting of 12 pages and 2 exhibits marked Boswell Second Supplemental and Stipulation Exhibits 1 and 2?

A. I did.

Q. Do you have any changes or corrections to your prefiled second supplemental and settlement testimony?

A. I do not.

Q. If I were to ask you those same questions today, would your answers be the same?

A. They would.

Q. Do you have any changes or corrections to your exhibits?

A. I do not.

Q. Ms. Boswell, did you prepare a summary of all of your testimonies?

A. I did.

MS. HOLT: Chair Mitchell, I would add that Ms. Boswell's summary was provided to the parties and to the Commission on September 8, 2020. And at this time, I move that Ms. Boswell's second supplemental and settlement testimony, and her summary, be entered into the record in this proceeding and copied into the record as if given orally from the stand, and that the exhibits attached to her second supplemental and settlement testimony be identified as marked when filed.

Ms. Boswell is available for cross examination.

MS. TOWNSEND: No questions from the Attorney General.

CHAIR MITCHELL: All right. Ms. Holt, I heard no objections to your motion as to Ms. Boswell's testimony and exhibits, so your motion will be allowed.

(Boswell Second Supplemental and Stipulation Exhibits 1 and 2 were identified as they were marked when prefiled.)

(Whereupon, the prefiled second

supplemental and settlement testimony and summary of testimony of Michelle M. Boswell were copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1213

DOCKET NO. E-7, SUB 1214

AND

DOCKET NO. E-7, SUB 1187

SECOND SUPPLEMENTAL AND SETTLEMENT TESTIMONY OF MICHELLE M. BOSWELL ON BEHALF OF THE PUBLIC STAFF NORTH CAROLINA UTILITIES COMMISSION

September 8, 2020

Q. MS. BOSWELL, WHAT IS THE PURPOSE OF YOUR SECOND SUPPLEMENTAL AND SETTLEMENT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to provide the Public Staff's revised calculation of its recommended revenue requirement in this proceeding, including the impacts of the Second Agreement and Stipulation of Partial Settlement (Second Partial Stipulation) between Duke Energy Carolinas, LLC (DEC or the Company) and the Public Staff (collectively, the Stipulating Parties), dated July 31, 2020, and the Company's May 2020 updates. On July 2, 2020, DEC witness Jane L. McManeus filed Second Supplemental Testimony and

Exhibits supporting a $29,037,000 decrease in DEC's original request for North Carolina retail revenue, for a total supported proposed increase of $416,024,000. On July 31, 2020, pursuant to the Second Partial Stipulation, DEC witness McManeus filed Second Settlement Testimony and Exhibits (Second Settlement Testimony) supporting a $30,898,000 decrease in DEC's original request for North Carolina retail revenue, for a total supported proposed increase of $414,433,000.

Also on July 31, 2020, Public Staff witnesses J. Randall Woolridge, James S. Mclawhorn, and I each filed Testimony Supporting Second Partial Stipulation, stating that the Second Partial Stipulation is in the public interest and should be approved. I further testified that once the Public Staff had completed the audit of all revenue, rate base, and expense updates through May 31, 2020, the Public Staff would file schedules supporting the Public Staff's recommended revenue requirement.

On September 4, 2020, the Commission issued an Order (September 4 Order) granting the Public Staff leave to file testimony and exhibits regarding the Company's Second Supplemental Testimony and CCR Testimony.

In accordance with the terms of the Second Partial Stipulation and the Commission's September 4 Order, I intend to (1) present the final audit results of settled and non-settled accounting and ratemaking adjustments as reflected in DEC's Second Settlement Testimony; (2) recommend additional adjustments as a result of information provided by the Company as a part of the audit performed; (3) reflect the impact of adjustments to the updates and corrections recommended by other Public Staff witnesses to the amounts presented in DEC's Second Settlement Testimony, and (4) present the Public Staff's recommended revenue requirement increase.

Q. WHAT UPDATED REVENUE INCREASE IS THE PUBLIC STAFF RECOMMENDING?

A. Based on the level of rate base, revenue, and expenses annualized at December 31, 2018, with certain updates, the Public Staff is recommending an increase in annual base rate operating revenue of $290,049,000.

Q. IS THE COMPANY'S SECOND SETTLEMENT TESTIMONY CONSISTENT WITH THE SECOND PARTIAL STIPULATION?

A. Except as described below and in the testimony filed by other Public Staff witnesses, the Second Settlement Testimony is consistent with the Second Partial Stipulation, as well as with the Agreement and Stipulation of Partial Settlement (First Partial Stipulation) between the Company and the Public Staff, filed by DEC in this proceeding on March 25, 2020.

Q. HAVE THE IMPACTS OF SETTLED AND UNSETTLED ISSUES BETWEEN THE COMPANY AND THE PUBLIC STAFF BEEN SATISFACTORILY CARRIED FORWARD INTO THE COMPANY'S SECOND SETTLEMENT TESTIMONY?

A. With regard to settled issues, yes, for the most part; however, there are certain instances, as described later in my testimony, in which I have found it appropriate and reasonable to make certain adjustments to carry forward the impact of settled issues fully and accurately, including updating items of revenue and cost to May 31, 2020.

With regard to unsettled issues, while the Company has not carried forward the impact of any Public Staff positions in its filing, I and other Public Staff witnesses are recommending adjustments to do so, and those adjustments are further described herein and reflected in Boswell Second Supplemental and Stipulation Exhibit 1.

Q. MS. BOSWELL, WHAT ADJUSTMENTS TO THE COMPANY'S SECOND SUPPLEMENTAL TESTIMONY AND EXHIBITS DO YOU RECOMMEND?

A. I am recommending adjustments in the following areas:

1) Updated Net Plant, Depreciation Expense, and Accumulated Depreciation
2) Update for New Depreciation Rates
3) Update of Revenues and related expenses to May 31, 2020

4) Update to Benefits
5) Cash Working Capital under Present Rates
6) Cash Working Capital Effect of Increase

Q. WHAT ADJUSTMENTS RECOMMENDED BY OTHER PUBLIC STAFF WITNESSES DO YOUR EXHIBITS INCORPORATE?

A. My exhibits reflect the following adjustments recommended by other Public Staff witnesses:

1) The revised recommendations of Public Staff witness Maness regarding ARO-related deferred environmental costs and the reclassification of non-ARO deferred environmental costs.

2) The recommendation of Public Staff witness Metz regarding project costs included in plant in service.

Q. WOULD YOU BRIEFLY DESCRIBE THE PUBLIC STAFF'S PRESENTATION OF THE REVENUE REQUIREMENT ASPECTS OF THE STIPULATION?

A. Yes. The attached Boswell Second Supplemental and Stipulation Exhibit 1 sets forth the accounting and ratemaking adjustments that I and other Public Staff witnesses are making to the revenue, expenses, rate base, and revenue requirement set forth in DEC's Second Settlement Testimony. I note that not until the Commission makes a determination regarding the yet unresolved issues (including, but not limited to, deprecation and coal ash disposal costs) can the settled accounting and ratemaking adjustments be finalized, and the resulting rate base, net operating income, return, and rate increase be calculated.

Q. PLEASE GIVE A MORE DETAILED DESCRIPTION OF THE ORGANIZATION OF YOUR EXHIBITS.

A. Schedule 1 of Boswell Second Supplemental and Stipulation Exhibit 1 presents a reconciliation of the difference between the Company's requested increase of $414,433,000 and the Public Staff's recommended increase of $290,049,000, including all adjustments included in the First and Second Partial Stipulations except for EDIT Riders.

Schedule 2 presents the Public Staff's adjusted North Carolina retail original cost rate base. The adjustments made to the Company's proposed level of rate base are summarized on Schedule 2-1 and are detailed on backup schedules.

Schedule 3 presents a statement of net operating income for return under present rates as adjusted by the Public Staff. Schedule 3-1 summarizes the Public Staff's adjustments, which are detailed on backup schedules.

Schedule 4 presents the calculation of required net operating income, based on the rate base and cost of capital recommended by the Public Staff.

Schedule 5 presents the calculation of the required decrease in operating revenue necessary to achieve the required net operating income. This revenue increase is equal to the Public Staff's recommended decrease shown at the bottom of Schedule 1.

Boswell Second Supplemental and Stipulation Exhibit 2 sets forth the calculation of an annual excess deferred income taxes (EDIT) Rider for all unprotected taxes to be in effect for five years, the calculation of a two-year Rider to refund the provisional taxes, and the calculation of a two-year Rider to refund the recent decrease of state taxes.

Q. PLEASE DESCRIBE YOUR RECOMMENDED ADJUSTMENTS NOT INCLUDED IN THE SECOND PARTIAL STIPULATION DESCRIBED ABOVE.

A. My adjustments are described below.

UPDATE FOR PLANT AND ACCUMULATED DEPRCIATION

Q. PLEASE EXPLAIN HOW YOU HAVE COMPUTED NET PLANT.

A. My calculation begins with plant, accumulated depreciation, and net plant based on the Company's actual per books plant in service and accumulated depreciation amounts as of the update period ending May 31, 2020, which include rate base and customer growth-related actual plant additions.

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN YOUR AMOUNT OF NET PLANT AND THE COMPANY'S AMOUNT.

A. I have reflected updated net plant for known and actual changes to depreciation expense and non-generation plant retirements that have been recorded between the end of the test year (December 31, 2018) and May 31, 2020. Furthermore, I have included three adjustments recommended by Public Staff witness Metz removing costs related to the Lincoln CT plant and the Company's camera replacement project. The Company has reflected updated net plant for known and actual changes to depreciation expense and non-generation plant retirements that have been recorded between the end of the test year and May 31, 2020, utilizing the depreciation rates recommended by Company witnesses. It is my understanding the Company agrees with the total plant in service and accumulated amounts calculated in Boswell Exhibit 1, Schedules 2-1(a)(1) and 2-1(a)(2).

UPDATE FOR NEW DEPRECIATION RATES

Q. PLEASE DESCRIBE YOUR ADJUSTMENT TO DEPRECIATION EXPENSE.

A. I have applied the deprecation rates previously recommended by Public Staff witness McCullar to the plant amounts updated through May 31, 2020, as adjusted per the recommendation of Public Staff witness Metz. I have, therefore, made an adjustment to depreciation expense to reflect witness McCullar's recommended depreciation rates.

UPDATE TO REVENUES AND RELATED EXPENSES

Q. PLEASE DESCRIBE YOUR ADJUSTMENT TO REVENUES AND RELATED EXPENSES.

A. I have updated the energy-related non-fuel variable O&M expense per KWh rate and the annual customer-related variable O&M expense per KWh rate to reflect the calculations to include amounts determined pursuant to the SCP allocation methodology. Furthermore, I have included the fuel factors recently approved by the Commission in Docket No. E-7, Sub 1228 in the calculation of annualized revenues and fuel expense, including growth, usage, and weather normalization impacts. It is my understanding the Company agrees with this adjustment.

BENEFITS

Q. PLEASE EXPLAIN THE ADJUSTMENT TO BENEFITS.

A. I have updated the benefits related to OPEB, pension, FASB 112, and non-qualified pensions to reflect the updated 2020 actuarial amounts that became available after the January 31, 2020, update period. It is my understanding the Company agrees with this adjustment.

CASH WORKING CAPITAL UNDER PRESENT RATES

Q. PLEASE EXPLAIN THE ADJUSTMENT TO CASH WORKING CAPITAL UNDER PRESENT RATES.

A. I have incorporated the update to May 31, 2020, of cash working capital under present rates. This cash working capital adjustment is reflected on Schedule 2-1 and incorporates the effect of the Public Staff's adjustments updated through May 31, 2020, before the rate increase, on the lead-lag study.

CASH WORKING CAPITAL EFFECT OF INCREASE

Q. PLEASE EXPLAIN THE ADJUSTMENT TO CASH WORKING CAPITAL FOR THE PROPOSED INCREASE.

A. The cash working capital lead-lag effect of the proposed revenue decrease as recommended by the Public Staff has been calculated on Boswell Second Supplemental and Stipulation Exhibit 1, Schedule 2-1.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Summary of the Testimony of Michelle M. Boswell

Docket No. E-7, Subs 1213, 1214, and 1187

The purpose of my testimony is to support the First and Second Agreement and Stipulation of Partial Settlements (Stipulations) between Duke Energy Carolinas, LLC (DEC or the Company) and the Public Staff, including updates of certain items to May 31, 2020, as well as to address unsettled items concerning depreciation and the sale of hydro facilities. The Stipulations set forth all the areas of agreement and details of the agreement between the Stipulating Parties, and my direct l, Supplemental and Stipulation,, and Second Supplemental and Stipulation testimonies address all settled and unsettled items and updates .

Boswell Second Supplemental and Stipulation Exhibits 1 and 2 set forth the accounting and ratemaking adjustments to which DEC and the Public Staff have agreed, as well as the remaining unsettled differences between the two parties. Until the Commission makes a determination regarding the unresolved issues involving coal ash costs, depreciation rates, and amortization of the hydro sales, the accounting and ratemaking adjustments cannot be finalized and the resulting rate base, net operating income, return, and rate increase cannot be calculated.

The most important benefits provided by the Stipulations from the perspective of the Public Staff, are (1) a significant reduction in the base non-fuel revenue increase requested in the Company's application, resulting from the adjustments agreed to by the Stipulating Parties, and (2) the avoidance of protracted litigation between the Stipulating Parties before the Commission and possibly appellate courts. Based on these ratepayer benefits as well as other provisions in the Stipulations, the Public Staff believes the Stipulations are in the public interest and should be approved.

Further, as provided for in the Second Stipulation, the Company updated certain items to May 31, 2020. The Public Staff has audited these items, and proposes several adjustments to these items as described in my Second Supplemental and Stipulation Testimony and Exhibits. The Company has indicated it agrees with these update-related adjustments proposed by the Public Staff.

There remain several unsettled items after the Stipulations, including the treatment of coal ash disposal and remediation costs (testified to by other Public Staff witnesses), the appropriate amortization period relating to the hydro station sales, and the depreciation rates related to the proposed early retirement of coal plants.

Hydro Station Sales

I have adjusted the amortization period for the loss on the sale of the hydro units to the overall remaining depreciable life of the assets of 20 years. In the present case, the Company has recommended an amortization period of 7 years, with the purpose of keeping the overall revenue requirement for the units much the same as before the sale occurred. In its filing for deferral accounting in Docket No. E-7, Sub 1181 (Sub 1181), the Company asserted that, through the transaction, the facilities would continue to serve the customers with clean renewable energy, but at a lower cost.

As the Public Staff stated in its comments in the Sub 1181 docket dated September 4, 2018, and its testimony filed in that docket on January 18, 2019, the amortization period for the regulatory asset should be set at 20 years, which is comparable to the period of time over which the facilities would have been depreciated if they had remained in service. At the time of the comments, the average remaining life of the facilities was 22.49 years. As of the end of 2019, the depreciable life is 19.95 years.

Depreciation on Proposed Early Retirement of Coal Plants

Based on the Company's testimony, the Company has indicated that it is planning to retire Units 4 and 5 of the Allen Power Station in 2024 and Unit 5 of the Cliffside Power Station in 2026. The details regarding the retirements of these generating plants are further discussed in the testimony of Public Staff witness Metz. As a result of these retirements, the Company has recommended a five-year depreciation rate for the plants. I have recommended that Public Staff witness McCullar restore the depreciation rate of these units to the depreciation rate approved in the Company's last general rate case in Docket No. E-7, Sub 1146. I have recommended this rate change for the following reasons. First, although the Company has stated in its testimony that it intends to retire these plants, it has not presently done so. Second, the Public Staff has consistently recommended leaving the depreciation rates set at the original retirement date of the plant, and, at the date of actual physical retirement, any remaining net book value be placed in a regulatory asset account and amortized over an appropriate period, to be determined in a future general rate case. The Public Staff believes it is appropriate to continue this consistent treatment of retired plants in the present case.

This concludes my summary.

CHAIR MITCHELL: We will proceed with cross examination. I've heard that the Attorney General has no questions for Ms. Boswell.

Any other cross examination for the witness?

MS. JAGANNATHAN: Chair Mitchell, this is Molly Jagannathan. No questions from Duke.

CHAIR MITCHELL: All right. Thank you, Ms. Jagannathan.

All right. Any questions from Commissioners from the witness, beginning with Commissioner Brown-Bland.

COMMISSIONER BROWN-BLAND: I do not have any questions.

CHAIR MITCHELL: All right. Commissioner Gray?

COMMISSIONER GRAY: No questions.

CHAIR MITCHELL: Commissioner Clodfelter?

COMMISSIONER CLODFELTER: Nothing from me.

CHAIR MITCHELL: Commissioner Duffley?

COMMISSIONER DUFFLEY: I have no questions.

CHAIR MITCHELL: And Commissioner Hughes?

COMMISSIONER HUGHES: No questions.

CHAIR MITCHELL: And Commissioner McKissick?

COMMISSIONER McKISSICK: No questions.

CHAIR MITCHELL: All right. Ms. Boswell, you got off easy this afternoon. All right. Ms. Holt, any additional motions related to this witness?

MS. HOLT: At this time I move the admission of Ms. Boswell's Second Supplemental and Settlement Testimony Exhibits 1 and 2.

CHAIR MITCHELL: All right. Hearing no objection to that motion, Ms. Holt, it is allowed.

(Boswell Second Supplemental and Stipulation Exhibits 1 and 2 were admitted into evidence.)

CHAIR MITCHELL: All right. Ms. Boswell, you may step down. Thank you very much.

All right. My notes indicate that we are now with CIGFUR's witness Phillips.

MS. DOWNEY: Chair Mitchell?

CHAIR MITCHELL: Yes, Ms. Downey.

MS. DOWNEY: Now that we've concluded the Public Staff's case, out an of an abundance of caution, and to the extent not done so already, we would move that all the Public Staff's testimony, exhibits introduced during the consolidated hearing or in this hearing be entered into evidence in this case.

CHAIR MITCHELL: All right. Ms. Downey, there has been no objection to your motion. We will take care to ensure that all the Public Staff's testimony and exhibits will be admitted into the record of evidence in this case.

(REPORTER'S NOTE: Please refer to transcript volume 17 to view the admission of Public Staff's prefiled testimony that was moved into evidence in the consolidated hearing.)

CHAIR MITCHELL: All right. Ms. Cress, we're with you. Call your witness, please, ma'am.

MS. CRESS: Thank you, Chair Mitchell. CIGFUR calls Nicholas Phillips, Jr. to the screen, to borrow from Mr. Neal's quote there.

CHAIR MITCHELL: All right.

Mr. Phillips, would you raise your right hand, please, sir?

Whereupon,

NICHOLAS PHILLIPS, JR.,

having first been duly affirmed, was examined and testified as follows:

CHAIR MITCHELL: All right. Ms. Cress, you may proceed.

MS. CRESS: Thank you, Chair Mitchell.

DIRECT EXAMINATION BY MS. CRESS:

Q. Good afternoon, Mr. Phillips. Would you please state your full name for the record?

A. Nicholas Phillips, Jr.

Q. And by whom are you employed, Mr. Phillips?

A. I'm employed by Brubaker & Associates in an office in a suburb of St. Louis called Chesterfield, Missouri.

Q. Okay. What is your business address, please, sir?

A. It's 16690 Swingley Road -- Swingley Ridge Road, Chesterfield, Missouri.

Q. And on whose behalf are you testifying here today?

A. I am testifying on behalf of CIGFUR.

Q. Okay. And did you, on February 18, 2020, cause to be filed in this docket prefiled direct testimony consisting of 47 pages, and an Appendix A, as well as four exhibits identified as NP Exhibits 1 through 4 to your direct testimony?

A. That is correct. That was my testimony and exhibits.

Q. And did you on September 10, 2020, cause to be filed in Docket Number E-7, Sub 1214-A, a summary of your prefiled direct testimony?

A. Yes, I did.

Q. And pursuant to the Commission's order, you are not going to read that order today -- or that summary, rather, today, but it has been provided to the Commission and to the parties; is that right?

A. That's my understanding, yes.

Q. And did you also cause to be filed in this docket on September 8, 2020, an errata sheet indicating one change to your prefiled direct testimony?

A. Yes, that's correct.

Q. And would you please identify that change for us?

A. Yes. On page 16 of my filed direct testimony, I removed the very last sentence on lines 15 through 17.

Q. Okay. And do you have any other changes to make to your prefiled direct testimony?

A. I do not.

Q. So if I were to ask you here today the same questions with that one correction that you've already spoken to, would your answers be the same?

A. Yes, they would.

Q. Okay.

MS. CRESS: At this time, Chair Mitchell, I move that Mr. Phillips' prefiled direct testimony consisting of 47 pages, to include one appendix and four exhibits, as well as Mr. Phillips' errata sheet and his witness summary, be entered into the record in this proceeding and copied into the record at this time as if given orally from the stand, and that his exhibits attached to his prefiled direct testimony be marked for identification and admitted into evidence as Phillips Direct Exhibits 1 through 4.

CHAIR MITCHELL: All right. Ms. Cress, hearing no objection to your motion, it is allowed.

(NP Exhibits 1 through 4 were identified as they were marked when prefiled.)

(Whereupon, the prefiled direct testimony with Appendix A and summary of testimony and errata of Nicholas Phillips, Jr. were copied into the record as if given orally from the stand.)

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Application of Duke Energy Carolinas, LLC For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina	)	**Docket No. E-7, Sub 1214**

<u>Direct Testimony of Nicholas Phillips, Jr.</u>

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Nicholas Phillips, Jr. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Managing Principal of Brubaker & Associates, Inc., energy, economic and regulatory consultants. Our firm and its predecessor firms have been in this field since 1937 and have participated in more than 1,000 proceedings in 40 states and in various provinces in Canada. We have experience with more than 350 utilities, including many electric utilities, gas pipelines, and local distribution companies. I have testified in many electric and gas rate proceedings on virtually all aspects of ratemaking. More details are provided in Appendix A of this testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am testifying on behalf of a group of intervenors designated as the Carolina Industrial Group for Fair Utility Rates ("CIGFUR III"),[1] a group of industrial customers that purchase power from Duke Energy Carolinas, LLC ("DEC" or "Company"). CIGFUR III's members purchase substantial amounts of electric power from DEC and are major employers in the counties where they have manufacturing plants. The jobs they provide are vital to the local economies. CIGFUR III members and other industrials provide high-wage jobs in the DEC service area. The economic effect of these jobs is of course multiplied by other businesses and jobs indirectly created because of the existence of CIGFUR III manufacturing operations.

Q HAVE YOU PRESENTED TESTIMONY IN PRIOR PROCEEDINGS BEFORE THE NORTH CAROLINA UTILITIES COMMISSION ("COMMISSION")?

A Yes. I have been involved in many prior proceedings before this Commission and have presented testimony in many of those proceedings, most recently in NCUC dockets G-9, Sub 743 and E-22, Sub 562. I have been involved with matters involving DEC for many years including DEC's previous base rate filing, E-7, Sub 1146, and other proceedings.

Q WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY?

A I present testimony pertaining to the appropriate cost allocation methodology for use in this proceeding and subsequent revenue distribution to the various customer classes of any increase granted by the Commission and the associated rate design. I also address the Company's requested Return on Equity ("ROE"). I discuss DEC's

[1]For the purposes of this proceeding, CIGFUR III members are: Clearwater Paper Corporation, Corning Incorporated, Kinder Morgan, Inc., Kimberly-Clark Corporation, and Messer.

proposed Grid Improvement Plan ("GIP") and deferral request. Lastly, I comment on DEC Rider EDIT-2.

Q DOES YOUR TESTIMONY ADDRESS DEC'S NEED FOR AN INCREASE IN ELECTRIC RATES?

A In order to make my presentation consistent with the revenue levels requested by DEC, I used their numbers for rate base, operating income, fuel, and rate of return. Use of these numbers should not be interpreted as an endorsement of them for purposes of determining the total dollar amount of rate increase to which DEC may be entitled.

Summary of Conclusions and Recommendations

Q WOULD YOU BRIEFLY SUMMARIZE YOUR RECOMMENDATIONS IN THIS PROCEEDING?

A Yes. A summary of my position and recommendations is listed below:

1. While DEC has proposed the continued use of the summer coincident peak ("SCP") cost of service study for the distribution of its requested increase to classes, DEC now plans its generating system based on its winter peak demand inclusive of its reserve requirements. DEC states that its planning has been based on winter peak demand since it performed a comprehensive reliability study in 2016. Despite this change that dates back to 2016, DEC proposes the continued case of the SCP method because many of its investments were constructed on that previous planning criteria. However, because DEC's cost of service and rates need to reflect current cost causation and provide price signals to ratepayers reflective of the loads that now drive DEC's planning and system expansion, DEC's proposed method of distributing the increase should be based on the annual winter coincident peak ("WCP") demand method. The rates resulting from this proceeding will be in place in 2021, five years after DEC changed its planning from the summer peaks to the winter peaks. Rates and price signals should reflect DEC's planning and cost structure. If the Commission is reluctant to endorse this change, it is recommended that the summer/winter peak demand method be used. Certainly rates should not ignore the planning peak used by DEC since 2016.

2. DEC's proposed method of distributing the rate increase to classes makes a 25% movement in the variance from current rates toward cost. This method contains mitigation and avoids abrupt changes in rates to all classes and is appropriate.

3. DEC's proposed demand charges for the Optional Power Service, Time of Use ("OPT-V") rate class continue to price summer demand significantly higher than winter demands. Present and proposed on-peak energy rates are significantly higher than the unit costs indicated by DEC's cost of service study. DEC's proposed rates do not reflect unit costs or the dominant winter peak demand used by DEC for planning. Therefore, any reduction to DEC's requested increase should be applied to reduce energy charges to achieve the authorized revenue level for Rate OPT-V. Additionally, summer period demand charges should be reduced to reflect the cost causation.

4. DEC should offer a cost based high load factor rate and allow existing load to receive service from Rate HP-Hourly Pricing. These cost based enhancements will help mitigate the projected decline in industrial sales and customers.

5. DEC's requested ROE of 10.30% is unreasonable and should be rejected. The national average authorized ROE for vertically integrated electric utilities is currently 9.73%. A reasonable ROE for DEC should not exceed the current national average for vertically integrated electric utilities.

6. DEC's proposed GIP and deferral request is to a certain extent similar to the rider approach proposed by DEC and rejected by the Commission in DEC's last general rate case, NCUC docket E-7, Sub 1146. There is no compelling evidence demonstrating that grid improvements warrant a departure from standard ratemaking historically used by this Commission. This plan would shift regulatory risk from investors to customers as well as allow DEC to pursue single-issue ratemaking. The deferral approach may also eliminate DEC's incentive to prudently manage costs between base rate cases. Additionally, the costs proposed to be deferred are not volatile or unpredictable.

7. DEC should be ordered to return excess tax payments from customers to customers as soon as possible.

Cost of Service and Rate Design Principles

Q PLEASE EXPLAIN THE BASIS FOR YOUR EVALUATION AND DESIGN OF RATES.

A The ratemaking process has three steps. First, the utility's total revenue requirement must be determined in order to learn whether an increase in revenues is necessary. Second, we must determine how any increase in revenues is to be distributed among the various customer classes. A determination of how many dollars of revenue should be produced by each class is essential for obtaining the appropriate level of rates.

Finally, individual tariffs must be designed to produce the required amount of revenues for each class of service and to reflect the cost of serving customers within the class.

The guiding principle at each step should be cost of service. In the first step – determining revenue requirements – it is universally agreed that the utility is entitled to an increase only to the extent that its actual cost of service has increased. If current rate levels exceed revenue requirement, a rate reduction is required. In short, rate revenues should equal actual cost of service. The same principle should apply in the second two steps. Each customer class should, to the extent practicable, produce revenues equal to the cost of serving that particular class, no more and no less. This may require a rate increase for some classes and a rate decrease for other classes. The standard tool for determining this is a class cost of service study that shows the rates of return on each class of service. Rate levels should be modified so that each class of service provides approximately the same rate of return. Finally, in designing individual tariffs, the goal should also be to relate the rate design to the cost of service so that each customer's rate equals, to the extent practicable, the utility's cost of providing that service.

Q WHY IS IT IMPORTANT TO ADHERE TO BASIC COST OF SERVICE PRINCIPLES IN THE RATE DESIGN PROCESS?

A The basic reasons for using cost of service as the primary factor in the rate design process are equity, engineering efficiency (cost minimization), conservation, and stability.

Q HOW IS THE EQUITY PRINCIPLE ACHIEVED BY BASING RATES ON COSTS?

A When rates are based on cost, each customer (to the extent practical) pays what it costs the utility to provide service to that customer, no more and no less. If rates are not based on cost of service, then some customers contribute disproportionately to the utility's revenues by subsidizing service provided to other customers. This is inherently inequitable.

Q HOW DO COST-BASED RATES ACHIEVE THE ENGINEERING EFFICIENCY (COST MINIMIZATION) OBJECTIVE?

A Cost minimization is achieved when customers receive the appropriate price signals through the rates that they pay. Rate design is the step that follows the allocation of costs to classes; it is important that the proper amounts and types of costs be allocated to the customer classes so that they may ultimately be reflected in the rates.

When the rates are designed so that the energy costs, demand costs, and customer costs are properly reflected in the energy, demand, and customer components of the rate schedules, respectively, customers are provided with the proper incentives to minimize their costs, which will in turn minimize the costs to the utility.

From a rate design perspective, over-pricing the energy portion of the rate and under-pricing the fixed components of the rate (such as customer and demand charges) will result in a disproportionate share of revenues being collected from high load factor customers.

Q HOW DO COST-BASED RATES FURTHER THE GOAL OF CONSERVATION?

A Conservation occurs when wasteful or inefficient uses are discouraged or minimized. Only when rates are based on actual costs do customers receive a balanced price signal against which to make their consumption decisions. If rates are not based on costs, then customers may be induced to use electricity inefficiently in response to the distorted signals. It is important that the costs associated with certain conservation and demand management programs should not create a new form of subsidization and move rates away from cost.

Q PLEASE DISCUSS THE STABILITY CONSIDERATION.

A When rates are closely tied to costs, the earnings impact on the utility of changes in customer use patterns will be minimized as a result of rates being designed in the first instance to track changes in the level of costs. Thus, cost-based rates provide an important enhancement to a utility's earnings stability, reducing its need for filings for rate increases.

From the perspective of the customer, cost-based rates provide a more reliable means of determining future levels of power costs. If rates are based on factors other than costs, it becomes much more difficult for customers to translate expected utility-wide cost changes (i.e., expected increases in overall revenue requirements) into changes in the rates charged to particular customer classes (and to customers within the class). This situation reduces the attractiveness of expansion, as well as of continued operations, because of the lessened ability to plan.

Q WHEN YOU SAY "COST," TO WHAT TYPE OF COST ARE YOU REFERRING?

A I am referring to the utility's "embedded" or actual accounting costs of rendering services; that is, those costs that are used by the Commission in establishing DEC's overall revenue requirement.

Q IN YOUR OPINION, IS IT APPROPRIATE TO CLASSIFY ALL PRODUCTION INVESTMENT AS DEMAND-RELATED?

A Yes. Consumers take for granted that when they flip the switch, an electric light or appliance will turn on and run. Since electric energy cannot be stored in large quantities for any significant length of time, utilities must provide adequate generating capacity to meet the demands of their customers when those customers decide to make those demands. Therefore, investment in generation plant is properly classified as a demand-related cost.

Q WHAT ABOUT THE ARGUMENT THAT SOME PORTION OF THE INVESTMENT IN BASE LOAD PLANT SHOULD BE CLASSIFIED AS ENERGY-RELATED, BASED ON THE THEORY THAT A UTILITY IS WILLING TO MAKE CERTAIN ADDITIONAL CAPITAL INVESTMENTS TO REDUCE ITS LEVEL OF FUEL COSTS?

A With respect to this argument, it should be noted that the economic choice between a base load plant and a peaking plant must consider both capital costs and operating costs, and therefore is a function of average <u>total</u> costs. The capital cost of peaking plants is lower than the capital cost of base load plants, but the operating costs of peaking plants are higher than the operating costs of base load plants. Moreover, when the hours of use are considered, the fixed cost per kWh for base load plant is usually less than the fixed cost per kWh for the peaking plant. Of course, since the fuel costs of base load plants are lower than the fuel costs of peaking plants, the overall cost per kWh for base load plants is also less than the overall cost per kWh for peaking plants.

It is necessary, therefore, to look at both capital costs and operating costs in light of the expected capacity factor of the plant. The fact that base load plants have lower fuel costs than peaking plants does not mean that the investment in base load plants is strictly to achieve lower fuel costs. Investment in a base load plant is made to achieve lower total costs, of which fixed costs and fuel costs are the primary ingredients.

For any given system, the capital costs are not a function of the number of kWh generated, but are fixed and therefore are properly related to system demands, not to kWh sold. These costs are fixed in that the necessity of earning a return on the investment, recovering the capital cost (depreciation), and operating the property are related to the existence of the property and not to the number of kWh sold. If sales volumes change, these costs are not affected, but continue to be incurred, making them fixed or demand-related in nature.

It is not proper to classify a portion of the fixed costs related to production based on energy. However, if an attempt were made to increase the allocation of investment to one group of customers, on the theory that those customers benefit more than others from the lower energy costs that result from the operation of a base load plant as opposed to a peaking plant, as done in the Summer Winter Peak and Average ("SWPA") method, the analysis should be carried to its logical conclusion. The logical conclusion would be to fairly and symmetrically allocate energy costs to the group of customers who are forced to bear the higher capital costs allocated to them on a kWh basis. Energy costs allocated to the high load factor class should recognize lower operating costs which result from the higher capital costs of the base load plants. The

SWPA method fails to allocate lower than average fuel costs to the high load factor customers.

Appropriate Cost of Service Study and Revenue Distribution

Q IS DEC'S PROPOSED COST OF SERVICE METHODOLOGY APPROPRIATE FOR USE IN THIS PROCEEDING?

A Yes, but with some modification. The cost study functionalizes and classifies costs in accordance with generally accepted cost of service principles. Demand-related costs are allocated on demands placed on the system. Energy-related costs are allocated on the quantity of energy consumed and customer-related costs are allocated on the number of customers. However, DEC should utilize its winter peak, which is now its planning peak, rather than its summer peak to allocate fixed production and transmission costs.

In summary, a single coincident peak demand allocation of fixed production and transmission costs has been approved by the Commission for DEC for decades. I continue to support a coincident peak methodology, but recommend that DEC be required to use the winter peak instead of the summer peak in its demand allocation factor for the reasons described below. I believe DEC has correctly allocated its distribution costs.

Q WHAT COST OF SERVICE STUDIES DID YOU HAVE AVAILABLE TO YOU IN CONNECTION WITH YOUR ANALYSIS?

A I had WCP, SCP and SWPA cost of service studies produced by DEC for the 12-month period ended December 31, 2018. DEC also provided assistance with its cost of service model in performing a 2CP cost of service study using the average of the single summer and single winter peaks ("S/WCP"). The most appropriate cost of service for use in this proceeding is the WCP responsibility method rather than the SCP proposed by DEC. Use of the WCP study will provide the most accurate evaluation of the cost to serve the various customer classes. The use of the WCP method is also the most consistent with actual load analysis and operation of the DEC electric system. Rates based on WCP method will send the correct price signals to customers and provide benefits to the system.

Q PLEASE SUMMARIZE THE RESULTS OF DEC'S PROPOSED COST OF SERVICE STUDY, AND PROPOSED REVENUE SPREAD.

A Schedule 1 of Exhibit NP-1 shows the results of DEC's test year adjusted SCP cost of service study at present and proposed rates. Schedule 2 of Exhibit NP-1 shows DEC's recommended distribution of its requested increase to classes.

Q HAVE YOU PROVIDED SIMILAR RESULTS FOR THE WCP AND S/WCP COST OF SERVICE STUDIES?

A Yes. Schedules 1 and 2 of Exhibit NP-2 show the results of DEC's test year adjusted WCP cost of service study and resulting revenue distribution to classes using the same 25% subsidy reduction methodology proposed by DEC. As previously stated, DEC's method of allocation is appropriate but must be updated to reflect the dominant winter peak. Exhibit NP-3 shows the cost of service results and revenue distribution based on the S/WCP method.

Q WHICH COST OF SERVICE STUDY DO YOU RECOMMEND?

A I recommend the use of the WCP cost of service study in this case. Over the last several years, DEC has transitioned from a summer peaking to a winter peaking utility, and the winter peak is used for system planning including the calculation of reserve margin, and the need for additional generation facilities.

Q WHY IS THE WCP COST OF SERVICE STUDY MORE APPROPRIATE THAN DEC'S PROPOSED SCP COST OF SERVICE STUDY?

A DEC has transitioned from a summer to a winter peaking utility. According to FERC Form-1 data from 2014 through 2018, three of the last five system peaks (60%) occurred during winter months. Additionally, DEC indicates that it has changed from using a summer planning peak to a winter planning peak since its 2016 IRP. DEC forecasts as peaking in the winter for the foreseeable future.

Because DEC has shifted from summer to winter capacity planning, the WCP cost of service study will provide the most accurate evaluation of the cost to serve various customer classes and most accurate price signals to customers. The WCP method is the most consistent with actual load analysis and operation of the DEC electric system.

Q IS THERE A TRANSITIONAL ALTERNATIVE IF THE WCP METHOD IS NOT ADOPTED AT THIS TIME?

A Yes. In the event that the Commission is reluctant to approve the WCP cost of service study at this time, I recommend the use of the S/WCP cost of service study summarized in Exhibit NP-3. This study would more accurately reflect cost causation and DEC's transition from summer to winter capacity planning than DEC's proposed SCP cost of service study.

Q IS A COST OF SERVICE STUDY THAT ALLOCATES A PORTION OF PRODUCTION PLANT ON ENERGY USAGE APPROPRIATE FOR USE IN THIS CASE?

A No. The SWPA was rejected by this Commission in DEP's prior rate case, E-2, Sub 1023. The major reasons for rejecting the SWPA include:

1. It unfairly over-allocates fixed production costs to high load factor customers, which includes the industrial or manufacturing customers which are declining in North Carolina.

2. It double counts loads by using a full average component and a full peak component. If an average component is used, the average is already included in the peak and double counted by the peak and average method.

3. The peak and average method is not symmetrical and does not allocate lower fuel costs to coincide with the above average capital costs allocated to high load factor classes.

4. The basic premise that utilities spend more on base load plants to achieve lower fuel costs is not valid in the current timeframe. Combined cycle plants have both lower capital and fuel costs compared to coal and nuclear facilities and are the preferred option of most utilities.

After lengthy discussion of the SWPA method in the DEP case, the Commission determined that a coincident peak demand allocation of production and transmission capacity costs was appropriate. This method properly allocates cost responsibility to customer classes and, if implemented properly, minimizes the need for new generating capacity consistent with DECs load management goals. To my knowledge, DEC has never used the SWPA method for sound reasons and it should not start now.

Q DO YOU AGREE WITH THE DEC FILED COST OF SERVICE STUDY WITH RESPECT TO THE ALLOCATION OF CERTAIN DISTRIBUTION FACILITIES?

A Yes. The DEC proposed study uses a minimum system (or other alternate technique) to properly classify a portion of distribution costs as customer-related, particularly for distribution plant accounts 364 through 368. These accounts relate to poles, lines, underground conduit and transformers. I agree with DEC witness Janice Hager regarding the allocation of distribution in costs. I should also note that the Public Staff concluded that the use of the minimum system method for classifying and allocating distribution costs is reasonable in a report issued in March, 2019, Docket No. E-100, Sub 162, pages 16-17.

Q WHY SHOULD THE COSTS ASSOCIATED WITH DISTRIBUTION PLANT ACCOUNTS 364 THROUGH 368 BE CLASSIFIED AND ALLOCATED ON BOTH A DEMAND AND CUSTOMER BASIS AS OPPOSED TO JUST A DEMAND BASIS AS PERFORMED IN DEC'S COST OF SERVICE STUDY?

A Classifying and allocating the costs associated with Distribution Plant Accounts 364 through 368 entirely on a demand basis is inconsistent with cost-causation and generally accepted costing methodology. The primary purpose of the distribution system is to deliver power from the transmission grid to the customer in various geographical locations with service at different voltage levels. Certain distribution investments must be made just to connect a customer to the system. Also, many equipment manufacturers have only minimum sized equipment available. Safety concerns and construction practices often require minimum sized equipment, which is not determined by demand. These investments are properly considered to be customer-related.

Q IS THIS A NEW COST OF SERVICE CONCEPT?

A No. The concept is known as the minimum distribution system ("MDS"), and has been accepted for decades as a valid consideration by numerous state public utility commissions. It has also been presented in the National Association of Regulatory Utility Commissioners Electrical Utility Cost Allocation Manual ("NARUC Manual") and the Gas Distribution Rate Design Manual published by NARUC.

The central idea behind the MDS concept is that there is a minimum cost incurred by any utility when it extends its primary and secondary distribution systems and connects customers to the distribution system. By definition, the MDS system comprises every distribution component necessary to provide service, i.e., meters, services, secondary and primary wires, poles, substations, etc. The cost of the MDS, however, is only that portion of the total distribution cost the utility must incur to provide service to customers. It does not include costs specifically incurred to meet the peak demand of the customers.

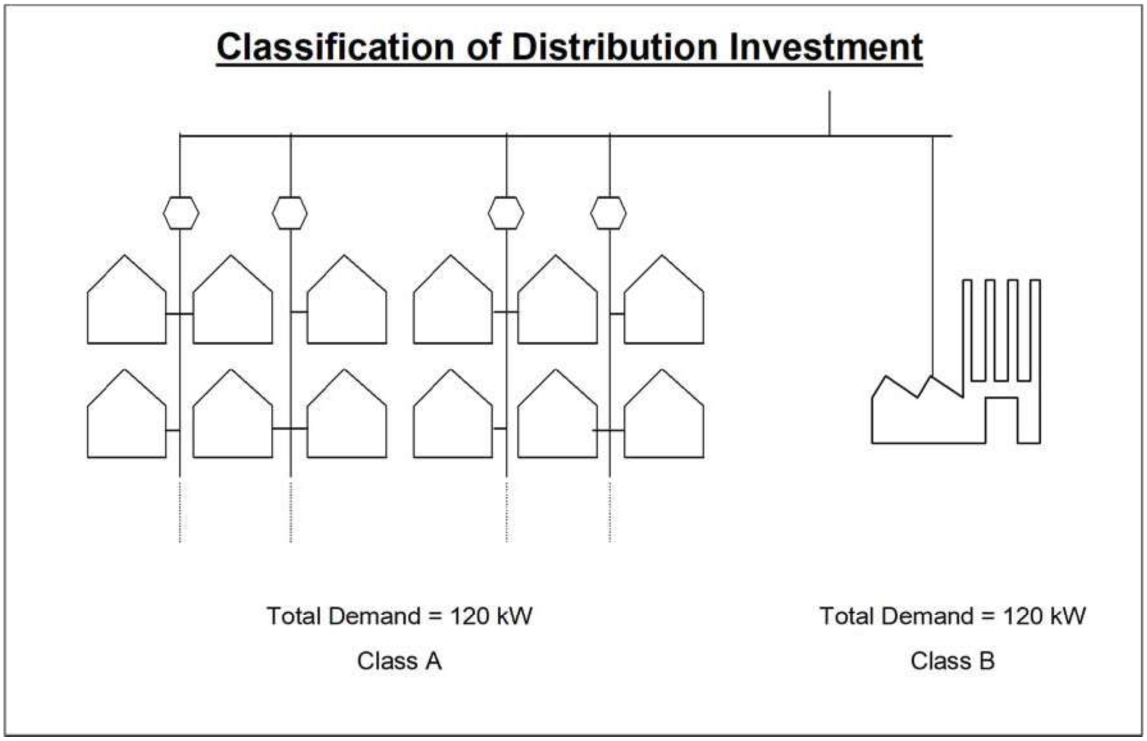
Q PLEASE ELABORATE FURTHER ON THE MDS CONCEPT AND THE DISTINCTION BETWEEN CUSTOMER-RELATED COSTS AND DEMAND-RELATED COSTS IN THE CONTEXT OF A CLASS COST OF SERVICE STUDY.

A A certain portion of the cost of the distribution system–poles, wires and transformers–is required just to attach customers to the system in different geographical locations, regardless of their demand or energy requirements. This minimum or "skeleton" distribution system can be considered as customer-related cost since it depends primarily on the number of customers, rather than on demand or energy usage.

Figure 1, as an example, shows the distribution network for a utility with two customer classes, A and B. The physical distribution network necessary to attach Class A is designed to serve 12 customers, each with a 10-kilowatt load, having a total demand of 120 kW. This is the same total demand as is imposed by Class B, which consists of a single customer. Clearly, a much more extensive distribution system is required to attach the multitude of small customers (Class A), than to attach the single larger customer (Class B), despite the fact that the total demand of each customer class is the same.

Even though some additional customers can be attached without additional investment in some areas of the system, it is obvious that attaching a large number of customers in different geographical locations requires investment in facilities, not only initially but on a continuing basis as a result of the need for maintenance and repair. Thus, part of the distribution system is classified as customer-related in order to recognize this area coverage requirement. It does not cost the same to serve the 12 customers on the left as it does to serve the one customer on the right. DEC's demand only allocation method and its refusal to use the minimal system allocation, results in those distinct costs being treated the same.

Figure 1



Q IN ADDITION TO THE AREA COVERAGE FACTOR YOU NOTED ABOVE, ARE THERE OTHER REASONS FOR CLASSIFYING PART OF THE DISTRIBUTION SYSTEM AS CUSTOMER-RELATED?

A Yes, there are. Safety and reliability are the best examples of these. A properly conducted class cost of service study must consider all cost-causing factors.

Q PLEASE EXPLAIN.

A When distribution engineers design the enhancement, upgrade, or extension of an electric system, they must be constantly aware of the operating parameters of the system. It is in the construction of the distribution system, however, that the *true cause* of many distribution costs is clearly seen. That cause is frequently *not* demand related.

An illustration helps make this point clear. Consider a customer who intends to build a home on a new lot, one that does not already have electrical service. This customer is cost and energy conscious and, thus, chooses to employ as many energy efficiency and conservation techniques and appliances as he can. After considerable research and consultation with experts, the customer calls the utility and advises that he will require service capable of providing a maximum peak demand of 2,000 watts (2 kW).

During the installation of the primary and secondary distribution extension to the customer's home, he notices that the linemen are using conductors, poles, cross-arms, and components identical to those serving the much larger, and less efficient, houses down the street. After more investigation, the customer learns that the distribution extension to his home is capable of carrying far greater demand than his home was designed to use. When he informs the utility of this 'error,' the utility explains that because of reliability and safety concerns it cannot install wires smaller than a certain size or hang them below a certain height. In short, there are specified minimum standards that the utility must meet that are wholly unrelated to the new home's reduced demand.

This illustration demonstrates that, although utilities design and install distribution equipment to satisfy their customers' need for electricity, there are factors other than electrical demand that force them to incur costs. Safety and reliability are as critical to every phase of design and construction as demand. Further, many equipment manufacturers have only minimum sized equipment available for installation. As one reviews the cost of the distribution system nearest the customer (i.e., that portion from the primary radial lines through the line transformers and secondary system), the cost incurred to comply with safety and reliability standards, as well as minimum sized equipment available, begins to outweigh the cost of meeting electrical demand.

Q CAN YOU CITE ANY AUTHORITATIVE PUBLICATIONS THAT SUPPORT ALLOCATING PART OR ALL OF PLANT ACCOUNTS 364 THROUGH 368 ON THE BASIS OF A CUSTOMER COMPONENT?

A Yes. In 1992, NARUC published the NARUC Manual which states:

> "Distribution Plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system. As shown in Table 6-1, each primary plant account can be separately classified into a demand and customer component. Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities." (NARUC Manual, page 90)

Table 6-1 from the NARUC Manual is included as Figure 2. It shows that Distribution Plant Accounts 364 through 368, which include conductors and support structures, have both a demand component and a customer component.

Figure 2

TABLE 6-1

CLASSIFICATION OF DISTRIBUTION PLANT[1]

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Distribution Plant[2]		
360	Land & Land Rights	X	X
361	Structures & Improvements	X	X
362	Station Equipment	X	-
363	Storage Battery Equipment	X	-
364	Poles, Towers, & Fixtures	X	X
365	Overhead Conductors & Devices	X	X
366	Underground Conduit	X	X
367	Underground Conductors & Devices	X	X
368	Line Transformers	X	X
369	Services	-	X
370	Meters	-	X
371	Installations on Customer Premises	-	X
372	Leased Property on Customer Premises	-	X
373	Street Lighting & Signal Systems[1]	-	-

[1]Assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2]The amounts between classification may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.

Q DO YOU RECOMMEND USE OF THE MINIMUM SYSTEM APPROACH FOR THE ALLOCATION OF DISTRIBUTION COSTS IN FUTURE PROCEEDINGS?

A Yes. I recommend the Commission accept the minimum system approach in the allocation of distribution costs as used by DEC in this proceeding.

Industrial Rate Design

Q DO YOU HAVE ANY CONCERNS REGARDING DEC'S PROPOSED RATE DESIGN?

A Yes. DEC's proposed rate design for the OPT-V customer class understates the demand charges while overstating the energy charges relative to the unit costs resulting from DEC's proposed SCP cost of service study. In addition, demand charges continue to charge much higher rates for the summer period than the winter period.

Q PLEASE DESCRIBE THE OPT-V RATE DESIGN.

A In general, the OPT-V rate structure consists of a monthly Basic Facilities charge, declining block demand charges and energy charges differentiated between on-peak and off-peak hours with an on-peak energy rate that is nearly twice as expensive as the off-peak rate. The OPT-V rates are also differentiated by service voltage (i.e., secondary, primary and transmission level), as well as by load size (i.e., small, medium and large).

Q HAVE YOU PREPARED A SCHEDULE COMPARING DEC'S OPT-V RATES TO THE UNIT COSTS FROM THE COMPANY'S COST OF SERVICE STUDY?

A To illustrate the issue, I have summarized DEC's current and proposed OPT-V rates for Transmission Service, Primary Service and Secondary Service in Exhibit NP-4, Schedule 1. This schedule also includes the proposed unit costs resulting from DEC's SCP cost of service study, which were contained in Item 45E of the Company's E-1 filing. DEC's proposed rates continue to contain energy charges for the on-peak period that exceed the unit cost of energy by approximately 100%.

Q WHAT IS YOUR RECOMMENDATION WITH REGARD TO RATE DESIGN FOR THE OPT-V RATE SCHEDULE?

A I recommend that any approved reduction to the Company's requested revenue requirement increase for the OPT-V class be used to reduce DEC's proposed on-peak energy rates, particularly for the Transmission Service and Large Primary Service customers. DEC proposed summer period demand charges should be reduced to achieve the approved revenue level for Rate OPT-V. As previously stated and shown on Exhibit NP-4, the on-peak energy rates for OPT-V customers are approximately 100% above the unit costs resulting from the Company's cost of service study. The Rate OPT-V energy charges should be reduced to better reflect actual energy costs.

Q WHAT DO YOU RECOMMEND REGARDING OTHER COST BASED IMPROVEMENTS TO DEC'S RATES?

A DEC calculates and files unit costs in its E-1 Item 45e filing. It follows that DEC should file rates reflective of those unit costs. Cost based price signals are important and can impact peak load growth, reducing the need for new generating facilities. In addition to Rate OPV, DEC should offer a cost based high load factor rate using actual unit costs. For the primary large category, a cost based high load factor rate would be as shown in the following table.

TABLE 1

Recommended High Load Factor Rate

	Rate/Unit Cost(1)
Customer	$ 15.52/month
Demand	14.14/kW
Energy	2.71/cents/kWh

(1)Based on current unit costs for OPT-Primary Large per DEC E-1 Item 45e filing SCP.

Any allowed rate increase would adjust those charges as would tax credits.

Q IS THERE ANY OTHER RATE OFFERING THAT WOULD PROVIDE BENEFICIAL COST BASED PRICE SIGNALS TO CUSTOMERS?

A Yes. It is recommended that customers be allowed to move existing load to the HP-Hourly Pricing rate. Hourly pricing should not be limited to new load. Hourly prices reflect actual cost by hour and are an excellent pricing mechanism.

DEC data forecasts a decline in industrial customers and industrial sales through 2025 while the residential and commercial sectors are growing. These cost based rate offerings will help mitigate the industrial sales decline and benefit the system.

Grid Improvement Plan

Q HAVE YOU REVIEWED DEC'S PROPOSED GIP DEFERRAL REQUEST?

A Yes. DEC is requesting permission to defer cost related to its GIP in a regulatory asset for recovery in future cases. DEC will recover its qualified plan costs in this case for test period expenditures and post test period updates. DEC is requesting to defer costs beginning January 1, 2020 for a three year period through 2022.

Q SHOULD THE DEFERRAL REQUEST BE APPROVED?

A No. The Commission should limit the use of special ratemaking for several reasons. First, deferral or other tracking mechanisms shift regulatory risk from investors to the Company's customers. Second, the use of these mechanisms allow utilities to pursue single-issue ratemaking, meaning that the Company could defer cost increases of its revenue requirement outside of a full base rate case but ignore cost decreases. This undermines the Commission's ability to evaluate the sufficiency of rates in the context of a full rate case proceeding based on the totality of the utility's revenues and costs for a given test year. Third, the use of deferrals can compromise utilities' incentives to minimize expenses and maximize revenues in between base rate proceedings. Fourth, the costs proposed to be deferred through the GIP are not volatile nor unable to be managed by the utility.

Q HOW WOULD THE USE OF THE GIP DEFERRAL TRANSFER RISK FROM THE UTILITY TO RATEPAYERS?

A Utilities typically recover the costs of capital projects through a rate case after project completion, i.e., when the investment is used and useful, and is providing a benefit to ratepayers. Under this method, if the utility cannot timely and prudently complete a project the utility bears the burden of its failure. DEC's authorized return fairly compensates it for bearing this risk. However, the GIP deferral would enable DEC to defer the cost of its investment for recovery, presumably with carrying costs. This would increase costs to ratepayers as compared to historical ratemaking used by this Commission.

Q IF THE GIP DEFERRAL IS APPROVED, HOW SHOULD THE RISK TRANSFER FROM INVESTORS TO RATEPAYERS BE ADDRESSED?

A DEC's proposed GIP deferral would shift regulatory risk from utility investors to customers by providing investors with an almost guaranteed recovery of specific expense items. Therefore, if the GIP deferral is approved DEC's allowed ROE should be reduced to reflect the reduced business risk that investors will face.

Q HOW WOULD THE USE OF THE GIP DEFERRAL BE A FORM OF SINGLE-ISSUE RATEMAKING?

A In establishing a utility's revenue requirement in a rate case, the Commission considers a myriad of investment, expense and revenue elements that together determine the appropriate level of rates. These elements include items such as utility rate base investments and offsets (e.g., depreciation reserve), operating expenses and savings from new investment or management/operation practices, cost of capital under current capital market conditions, utility sales (and revenue) growth and other factors. North Carolina's long-standing rate case process of looking at all of the utility's investments, expenses and revenues during a test year period has worked well and allows the Commission to fairly and transparently balance the interests of ratepayers and the utility.

In between rate cases, some utility cost or revenue elements may increase, but this may be offset by decreases in other cost elements or sales growth which increase revenues. Since all of these factors combine to determine proper rates looking at selected cost elements in isolation between comprehensive rate cases can tilt the balance of costs, savings and revenues that determine appropriate rate levels. This is what I consider to be single-issue ratemaking, and this is what DEC's proposed GIP deferral will do. Mechanisms that modify normal regulation for a single element or category of costs without regard to potential offsets should be avoided.

Q HOW CAN DEFERRALS DISTORT OR COMPROMISE INCENTIVES TO PRUDENT UTILITY OPERATIONS?

A During the period between rate cases, a utility has a strong incentive to control its costs to be more profitable to its shareholders and to diminish the need for future rate cases. Between rate cases, a utility has a profit motivation that causes it to be diligent and efficient in managing its operations, seeking the best pricing possible for its needed facilities, equipment, etc., since it benefits directly from the cost savings. Since the GIP deferral would allow an almost guaranteed recovery of the cost of grid modernization, plus a return, DEC has a far weaker incentive to be as diligent or efficient in its procurement and operations.

Q ARE THE COSTS PROPOSED TO BE COLLECTED THROUGH THE GIP DEEFERRAL VOLATILE AND UNABLE TO BE MANAGED BY DEC?

A No. According to DEC witness Jay W. Oliver, the Company has a well-thought out plan to modernize and maintain the transmission and distribution grid. Mr. Oliver has also provided a plan outlining some of the capital costs DEC expects to incur on grid modernization projects over the next few years. Therefore, the costs proposed to be recovered through the GIP deferral are not unpredictable nor outside of the Company's control.

Q HAS DEC DEMONSTRATED A NEED TO DEFER ITS GRID INVESTMENTS?

A No. As discussed above, these are planned investments within DEC's control. Additionally, DEC has an obligation to provide safe and reliable electric service to its customers. If grid modernization is required to meet that obligation, or certain grid investments are required by law, DEC is likely to make those investments with or without a deferral mechanism. Thus, DEC has not demonstrated the need to defer the costs of grid modernization as opposed to the traditional rate case process.

Return on Equity & Capital Structure

Q IS DEC'S PROPOSED 10.30% ROE APPROPRIATE?

A No. DEC's requested ROE of 10.30% is excessive when compared with recent rate ROEs approved by commissions nationwide and the Commission's recent decisions and should be rejected. The Company's current authorized ROE is 9.9%, which was authorized in the Commission's Final Order in Docket No. E-7, Sub 1146, issued on June 22, 2018. It is important to note that, market costs of capital have not increased since DEC's last rate case. Further, the national average ROE has been below 10% for electric utilities since 2014.

Every quarter, Regulatory Research Associates, an affiliate of SNL Financial, updates its *Major Rate Case Decisions* report that covers electric and natural gas utility rate case outcomes. Specifically, this report tracks the authorized ROEs resulting from utility rate cases. The most recent report issued January 31, 2020 has been updated through December 31, 2019, and shows that the average authorized ROE for vertically integrated electric utilities in rate cases (and excluding limited-issue rider cases) decided during 2019 was 9.73%. This is 17 basis points below DEC's currently authorized ROE of 9.9% and 57 basis points below DEC's requested ROE of 10.30% in its current application.

Further, DEC's requested ROE of 10.30% is inconsistent with ROEs authorized by the Commission in recent general rate cases. I have prepared the following table illustrating the Commission's authorized ROEs for electric and natural gas utilities for the past decade.

TABLE 2

NCUC's Authorized ROEs

Company	Service	NCUC Docket	Date of Order	NCUC Allowed Return on Equity
DEC	Electric	E-7, Sub 909	12/7/2009	10.70%
DENC	Electric	E-22, Sub 459	12/13/2010	10.70%
DEC	Electric	E-7, Sub 989	1/27/2012	10.50%
DENC	Electric	E-22, Sub 479	12/21/2012	10.20%
DEP	Electric	E-2, Sub 1023	5/30/2013	10.20%
DEC	Electric	E-7, Sub 1026	9/24/2013	10.20%
PNG	Gas	G-9, Sub 631	12/17/2013	10.00%
PSNC	Gas	G-5, Sub 565	10/26/2016	9.70%
DENC	Electric	E-22, Sub 532	12/22/2016	9.90%
DEP	Electric	E-2, Sub 1142	2/23/2018	9.90%
DEC	Electric	E-7, Sub 1146	6/22/2018	9.90%
PNG	Gas	G-9, Sub 743	10/31/2019	9.70%
DENC	Electric	E-22, Sub 562	1/23/2020[1]	9.75%

[1]Notice of Decision

As is evident from the table, the Commission has not approved an authorized ROE in excess of 10.00% since 2013 and has not approved an ROE in excess of 10.30% since 2012. DEC's proposed 10.30% ROE is inconsistent with broader electric industry trends and the Commission's recent decisions. Finally, the Commission should carefully consider how its authorized ROE impacts industrial ratepayers competing in the global market. I recommend that the Commission authorize a ROE that does not exceed the national average of 9.73%.

Q IS DEC'S PROPOSED CAPITAL STRUCTURE OF 53.00% EQUITY APPROPRIATE?

A Nationally, Regulatory Research Associates' *Major Rate Case Decisions* reports that "to offset the negative cash flow impact of federal tax reform, many utilities sought higher common equity ratios," nonetheless the average authorized equity ratio for electric utility cases nationwide was 49.94% during 2019 and 51.55% excluding jurisdictions that authorize capital structures that include cost-free items or tax credit balances.

Further, DEC's requested capital structure is inconsistent with those authorized by the Commission in recent general rate cases. I have prepared the following table illustrating the Commission's approved equity percentage of overall capital structure for electric and natural gas utilities for the past decade.

TABLE 3

NCUC's Approved Equity Percentage

Company	Service	NCUC Docket	Date of Order	NCUC Allowed % Equity
DEC	Electric	E-7, Sub 909	12/7/2009	52.50%
DENC	Electric	E-22, Sub 459	12/13/2010	51.00%
DEC	Electric	E-7, Sub 989	1/27/2012	53.00%
DENC	Electric	E-22, Sub 479	12/21/2012	51.00%
DEP	Electric	E-2, Sub 1023	5/30/2013	53.00%
DEC	Electric	E-7, Sub 1026	9/24/2013	53.00%
PNG	Gas	G-9, Sub 631	12/17/2013	50.66%
PSNC	Gas	G-5, Sub 565	10/26/2016	52.00%
DENC	Electric	E-22, Sub 532	12/22/2016	51.75%
DEP	Electric	E-2, Sub 1142	2/23/2018	52.00%
DEC	Electric	E-7, Sub 1146	6/22/2018	52.00%
PNG	Gas	G-9, Sub 743	10/31/2019	52.00%
DENC	Electric	E-22, Sub 562	1/23/2020(1)	52.00%

(1)Notice of Decision

As is evident from the table, the Commission has not approved a capital structure with 53.00% equity since 2013. DEC's proposed equity percent is inconsistent with broader electric industry trends and the Commission's recent decisions. I recommend that the Company's capital structure not exceed 52.00% equity.

Q IS CIGFUR I SUGGESTING THAT THE COMMISSION IS BOUND BY NATIONAL TRENDS OR THE FINDINGS OF OTHER STATE COMMISSIONS?

A No. The Commission is not bound by the decisions of other state regulatory commissions. Also, it is important to note that each commission considers the unique circumstances in each specific case in arriving at a regulated utility's authorized ROE and capital structure. However, I believe this information is illustrative of national trends in authorized ROEs and capital structures of regulated electric utilities that compete in the same capital markets as DEC's. Evidence of national trends may serve as a general gauge of reasonableness for the cost-of-equity and capital structure recommendations presented in this proceeding.

Rider EDIT-2

Q HAVE YOU REVIEWED DEC'S PROPOSAL TO REFUND EXCESS DEFERRED INCOME TAXES ("EDIT") TO CUSTOMERS?

A Yes. DEC is proposing to credit customers through Rider EDIT-2 for five categories of taxes that is obligated to refund. In my opinion, the Commission should use its discretion to require DEC to refund unprotected EDIT as expediently as possible to the ratepayers. Further, I respectfully urge the Commission to reject DEC's proposal to refund the unprotected "PPE-EDIT" over a prolonged period.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Nicholas Phillips, Jr.

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Nicholas Phillips, Jr. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.

A I graduated from Lawrence Institute of Technology in 1968 with a Bachelor of Science Degree in Electrical Engineering. I received a Master's of Business Administration Degree from Wayne State University in 1972. Since that time I have taken many Masters and Ph.D. level courses in the field of Economics at Wayne State University and the University of Missouri.

I was employed by The Detroit Edison Company in June of 1968 in its Professional Development Program. My initial assignments were in the engineering and operations divisions where my responsibilities included the overhead and underground design, construction, operation and specifications for transmission and distribution equipment; budgeting and cost control for operations and capital expenditures; equipment performance under field and laboratory conditions; and emergency service restoration. I also worked in various districts, planning system expansion and construction based on increased and changing loads.

Since 1973, I have been engaged in the preparation of studies involving revenue requirements based on the cost to serve electric, steam, water and other portions of utility operations.

Other responsibilities have included power plant studies; profitability of various segments of utility operations; administration and recovery of fuel and purchased power costs; sale of utility plant; rate investigations; depreciation accrual rates; economic investigations; the determination of rate base, operating income, rate of return; contract analysis; rate design and revenue requirements in general.

I held various positions at Detroit Edison, including Supervisor of Cost of Service, Supervisor of Economic studies and Depreciation, Assistant Director of Load Research, and was designated as Manager of various rate cases before the Michigan Public Service Commission and the Federal Energy Regulatory Commission. I was acting as Director of Revenue Requirements when I left Detroit Edison to accept a position at Drazen-Brubaker & Associates, Inc., in May of 1979.

The firm of Drazen-Brubaker & Associates, Inc. was incorporated in 1972 and has assumed the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. In April 1995, the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and staff.

Our firm has prepared many studies involving original cost and annual depreciation accrual rates relating to electric, steam, gas and water properties, as well as cost of service studies in connection with rate cases and negotiation of contracts for substantial quantities of gas and electricity for industrial use. In these cases, it was necessary to analyze property records, depreciation accrual rates and reserves, rate base determinations, operating revenues, operating expenses, cost of capital and all other elements relating to cost of service.

In general, we are engaged in valuation and depreciation studies, rate work, feasibility, economic and cost of service studies and the design of rates for utility services. In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

Q WHAT ADDITIONAL EDUCATIONAL, PROFESSIONAL EXPERIENCE AND AFFILIATIONS HAVE YOU HAD?

A I have completed various courses and attended many seminars concerned with rate design, load research, capital recovery, depreciation, and financial evaluation. I have served as an instructor of mathematics of finance at the Detroit College of Business located in Dearborn, Michigan. I have also lectured on rate and revenue requirement topics.

Q HAVE YOU PREVIOUSLY APPEARED BEFORE A REGULATORY COMMISSION?

A Yes. I have appeared before the public utility regulatory commissions of Arkansas, Delaware, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Missouri, Montana, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, South Dakota, Virginia, West Virginia, and Wisconsin, the Lansing Board of Water and Light, the District of Columbia, and the Council of the City of New Orleans in numerous proceedings concerning cost of service, rate base, unit costs, pro forma operating income, appropriate class rates of return, adjustments to the income statement, revenue requirements, rate design, integrated resource planning, power plant operations, fuel cost recovery, regulatory issues, rate-making issues, environmental compliance, avoided costs, cogeneration, cost recovery, economic dispatch, rate of return, demand-side management, regulatory accounting and various other items.

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Summary of Direct Testimony of Nicholas Phillips, Jr.
On behalf of Carolina Industrial Group for Fair Utility Rates III
Docket No. E-7, Sub 1214

My name is Nicholas Phillips, Jr., and I am a consultant in the field of public utility regulation and a Managing Principal of Brubaker & Associates, Inc. ("Brubaker"), energy, economic, and regulatory consultants. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017. Brubaker has been in this field since 1937 and has participated in more than 1,000 proceedings in 40 states and in various provinces in Canada. We have experience with more than 350 utilities, including many electric utilities, gas pipelines, and local distribution companies. In addition to having testified before this Commission in numerous proceedings including the preceding general rate case for Duke Energy Carolinas, LLC ("DEC" or the "Company"), Docket No. E-7, Sub 1146, I have testified before this Commission in many electric and gas rate proceedings on virtually all aspects of ratemaking. More details supporting my qualification as an expert witness in this proceeding are provided in Appendix A to my direct testimony filed in this docket.

I am testifying in this proceeding on behalf of a group of intervenors designated as the Carolina Industrial Group for Fair Utility Rates III ("CIGFUR III"), a group of industrial customers that purchase power from DEC. CIGFUR III's members purchase substantial amounts of electric power from DEC and are major employers in the counties where they have manufacturing plants. The jobs they provide are vital to the local economies. CIGFUR III members and other industrials provide high-wage jobs in the DEC service area. The economic effect of these jobs is of course multiplied by other businesses and jobs indirectly created because of the existence of CIGFUR III manufacturing operations.

A summary of my position and recommendations included in my direct testimony[1] follows: While DEC has proposed the continued use of the summer coincident peak ("SCP") cost of service study for the distribution of its requested increase to classes, DEC now plans its generating system based on its winter peak demand inclusive of its reserve requirements. DEC states that its planning has been based on winter peak demand since it performed a comprehensive reliability study in 2016. Despite this change that dates back to 2016, DEC proposes the continued case of the SCP method because many of its investments were constructed on that previous planning criteria. However, because DEC's cost of service and rates need to reflect cost causation and provide price signals to ratepayers reflective of the loads that now drive DEC's planning and system expansion, DEC's proposed method of distributing the increase should be based on the annual winter coincident peak ("WCP") demand method. The rates resulting from this proceeding will be in place in 2021, five years after DEC changed its planning from the summer peaks to the winter peaks. Rates and price signals should reflect DEC's planning and cost structure. If the Commission is reluctant to endorse this change, it is recommended that the summer/winter peak demand method be used. Certainly rates should not ignore the planning peak used by DEC since 2016.

DEC's proposed method of distributing the rate increases to classes makes a 25% movement in the variance from the current rates toward cost. This method contains mitigation and avoids abrupt changes in rates to all classes and is appropriate.

DEC's proposed demand charges for the Optional Power Service, Time of Use ("OPT-V") rate class continue to price summer demand significantly higher than winter demands. Present and proposed on-peak energy rates are significantly higher than the unit costs indicated by DEC's cost

[1] My direct testimony in this docket was filed on February 18, 2020. After the filing of my direct testimony, CIGFUR III and DEC entered into an Agreement and Stipulation of Settlement (the "Agreement"). I support the Agreement and believe it is reasonable, in the public interest, and should be accepted and approved by the Commission. I look forward to the opportunity to provide live testimony to this effect.

of service study. DEC's proposed rates do not reflect unit costs or the dominant winter peak demand used by DEC for planning. Therefore, any reduction to DEC's requested increase should be applied to reduce energy charges to achieve the authorized revenue level for Rate OPT-V. Additionally, summer period demand charges should be reduced to reflect the cost causation.

DEC should offer a cost based high load factor rate and allow existing load to receive service from Rate HP-Hourly Pricing. These cost based enhancements will help mitigate the projected decline in industrial sales and customers.

DEC's requested ROE of 10.30% is unreasonable and should be rejected. The national average authorized ROE for vertically integrated electric utilities is currently 9.73%. A reasonable ROE for DEC should not exceed the current national average for vertically integrated electric utilities.

DEC's proposed GIP and deferral request[2] is to a certain extent similar to the rider approach proposed by DEC and rejected by the Commission in DEC's last general rate case, Docket No. E-7, Sub 1146. There is no compelling evidence that grid improvements warrant a departure from standard ratemaking historically used by this Commission. This plan would shift regulatory risk from investors to customers as well as allow DEC to pursue single-issue ratemaking. The deferral approach may also eliminate DEC's incentive to prudently manage costs between base rate cases. Additionally, the costs proposed to be deferred are not volatile or unpredictable.

DEC should be ordered to return excess tax payments from customers to customers as soon as possible.

[2] My initial concerns about the proposed GIP Program have been sufficiently assuaged by the safeguards provided for in both the Agreement as well as Duke's Second Stipulation and Agreement with the Public Staff, both of which occurred after I filed my direct testimony in this docket.

This concludes my summary.

BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1214

In the Matter of Application by Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina	CIGFUR III'S CORRECTIONS TO DIRECT TESTIMONY OF WITNESS NICHOLAS PHILLIPS, JR.

CORRECTIONS TO THE DIRECT TESTIMONY OF

NICHOLAS PHILLIPS, JR.

Mr. Phillips' direct testimony should be corrected as follows:

The last sentence on page 16, beginning with the end of line 15 and concluding with line 17, should be stricken in its entirety, as follows:

~~DEC's demand only allocation method and its refusal to use the minimal system allocation, results in those distinct costs being treated the same.~~

Q. Okay. Mr. Phillips, how long have you been in the field of public utility regulation?

A. A long time. I worked for a utility as a young engineer for Detroit Edison designing distribution circuits overhead and underground, and then moved into their rate department. I then became a consultant. At that time, it was Drazen-Brubaker, and subsequently changed to Brubaker & Associates. Along the way, I guess pertinent things I've been hired by and testified for the Office of Regulatory Staff of South Carolina, presented testimony on their behalf in two Duke proceedings. And I guess I've been hired to do an arbitration involving the Catawba plant there owned by Duke, or owned by Duke and others.

MS. CRESS: Chair Mitchell, at this time I would like to ask permission to ask Mr. Phillips a series of questions on direct examination as part of CIGFUR's response to Public Staff witness Floyd's second supplemental testimony filed in this docket. This was something that was discussed by the parties during break off the record, and it's my understanding that the parties are aware that I plan to ask some questions this morning. So assuming that they don't have any heartburn, I know they are planning to do cross where cross was previously waived, so I would just ask your permission.

CHAIR MITCHELL: All right. Hearing no objection from any of the parties, you may proceed, Ms. Cress.

MS. CRESS: Thank you.

Q. Mr. Phillips, just diving right in here.

Were you surprised to learn that there was opposition to a few of the provisions contained within CIGFUR's settlement?

A. Yes, I was.

Q. Why were you surprised?

A. Well, we filed the settlement after months of negotiations with Duke trying to resolve issues in this case that was prolonged, I guess, due to the COVID.

MS. DOWNEY: Chair Mitchell, objection, relevance. I don't see how this is relevant.

MS. CRESS: I would contend it's absolutely relevant to the prejudice that CIGFUR would contend we faced as a result of Mr. Floyd's second supplemental testimony.

MS. DOWNEY: Which is why he's up here today.

MS. CRESS: That's actually incorrect. He's up here today because the Commission denied CIGFUR's motion to excuse him after no parties had any cross, because the Commission indicated that it wanted to ask him some questions.

CHAIR MITCHELL: All right. Ms. Cress, I'm going to allow you to proceed. I'm going to overrule the objection. Ms. Cress, please move efficiently through your questions. They should be tailored to address the issues that were raised in the supplemental settlement testimony filed by the Public Staff. So please proceed, but proceed efficiently.

MS. CRESS: Understood. Thank you, Chair Mitchell.

Q. Could you finish giving your answer, Mr. Phillips; why were you surprised?

A. I was surprised because, after negotiating with Duke, this settlement was filed, I think, at the end of May. And then there was a second settlement between the Public Staff and Duke two months later, and they didn't mention any problems with our settlement. In fact, I thought the Public Staff did a good job. They expanded to find a few things in our settlement better on the grid improvement plan, and lowered the ROE. We had asked for some cost of service studies and rates to be looked at, and the Public Staff actually expanded that.

So with that in mind, when Mr. Floyd filed his second supplemental testimony and took issue with some aspects of our settlement, I was surprised.

Q. Did you have occasion to listen to Mr. McLawhorn's and Mr. Floyd's testimony provided in this case?

A. Yes, I did.

Q. And I believe you insinuated as much in your last answer, but just to be clear, you have had occasion to read Mr. Floyd's second supplemental prefiled testimony in this docket?

A. Yes, I did.

Q. Okay. After hearing and reading such testimony, do you feel as though you have a better understanding about what exactly the Public Staff takes issue with in regards to the CIGFUR settlement?

A. Yes. After reading it and listening, I thought that their main issue had to do with subtracting some curtailable or nonfirm load from the peak demand allocator. And there was some general things said by Mr. Floyd where he just didn't appreciate some rate things being settled where he wanted to do a pretty large rate design study between this and sometime in the future, which may or may not be when Duke files their next general rate case.

So I -- after reviewing it, I didn't think it was worth all the trouble that's come about from this, because -- I guess I'll go on. The things that Duke agreed to present in a future case would be subject to review in the future case, and the Public Staff could comment on anything they disagree with at that time instead of now.

Q. So this future rate design study that Mr. Floyd has testified about extensively, does that change anything about the fact that the Commission still has to set rates in this case that we're here for today?

A. Yes. I was trying to explain that, and you probably did it better. There's two things going on. One is we have a rate case. Duke has a time schedule where they can put temporary rates into effect, and this case has to have some decisions, and rates have to be set. We -- certain things we can't rate for future studies. And with our experience, sometimes future studies don't happen as fast as you think that they might.

Q. So would the Commission's hands be tied in future rate cases if it were to approve CIGFUR's settlement in this rate case?

A. No. All of the things that we asked for in the future are contingent on Commission approval. There's nothing -- there's nothing that could tie the Commission's hands, and I don't think -- I'm not an attorney, but I don't think two parties can enter a settlement that tie the Commission's hands in a future case.

Q. Let's talk about removing curtailable load from the energy allocator. Tell us where the disagreement lies with respect to this issue.

A. Yes. I think you misspoke. It's the demand allocator.

Q. My apologies. Thank you.

A. In my view, when Duke has curtailable load, it does not need to build or buy capacity to serve that load. So I believe it's correct to remove that load from the demand allocator. The second, this is an unusual proceeding, because if Duke called a curtailment on its peak day, that day occurred in the winter of the test period, and we're allocating costs on the summer peak day. So you need to make some adjustments even if Duke didn't call a curtailment.

Finally, another thing -- and I don't want to get into the weeds and prolong this hearing, but if you give customers a credit for substandard service, and service that Duke can shut off is substandard service, so you deserve a lower rate or a credit. So if you have a lower rate or lower revenues and you allocate rate base based on the total firm load and curtailable load, I think you have a mismatch, and with less revenues, you would lower the rate of return. And I guess Mr. Floyd, with a lower rate of return, would give it an above average increase.

But I think those are things that need to be discussed and hammered out. And we don't have a proposal before us today with testimony explaining it, and that's why I'm hesitant to prolong this, because I don't think this issue is before the Commission now, and I feel awkward discussing it; but I also feel we needed to respond to the supplemental testimony of Mr. Floyd.

Q. And did the Public Staff, at any time, reach out to CIGFUR to discuss this issue prior to the evidentiary hearing in this rate case?

A. No, not to my knowledge. And that's why I was surprised, after all the time that went by, that this issue was taken up by Mr. Floyd's second supplemental testimony.

Q. Would CIGFUR have been willing to discuss this issue with the Public Staff had they brought it to our attention?

MS. DOWNEY: Chair Mitchell, excuse me. Same objection, relevance.

MS. CRESS: Again, Chair Mitchell -- I'm demonstrating --

CHAIR MITCHELL: Overruled. Proceed, Ms. Cress.

THE WITNESS: Yeah. I was just going to say that James McLawhorn and Jack Floyd are good engineers and good rate people, and I've worked with them in a number of cases and resolved a lot of issues, but there needs to be an exchange of ideas for that to happen.

Q. What would you say in response to witness Floyd's testimony during the consolidated hearing that provided, in pertinent part, quote, this one reason the staff has had a little consternation, a little heartburn over a couple of these settlements, because these settlements are starting to pin down specific pieces of rate design and potentially cost of service that advantage certain customers. And anytime that happens, my comprehensive study that I'd like to see becomes a little less comprehensive.

What's your reaction to that testimony?

A. I don't think anything that CIGFUR is doing is going to hamper any future studies. In fact, CIGFUR's settlement asks for some studies to be done by Duke. I don't understand this heartburn. I know it's hard to get all the parties together to come to a collaborative process, but in the past I think CIGFUR's been helpful in all regards of getting things done.

MS. CRESS: I will reserve the rest of my questions for a later time. Thank you, Chair Mitchell.

CHAIR MITCHELL: All right. Ms. Cress, I assume your witness is available for cross examination?

MS. CRESS: He is. And for questions by the Commission.

CHAIR MITCHELL: All right. Ms. Downey.

MS. DOWNEY: I just have one set of

questions.

CROSS EXAMINATION BY MS. DOWNEY:

Q. Mr. Phillips, to you have your CIGFUR settlement in front of you?

A. I will have it.

Q. I believe you just --

A. I have it.

Q. Sorry?

A. I just said I have it.

Q. Okay. I believe you just told Ms. Cress that none of the provisions of the settlement agreement refer to decisions that the Commission needs to make now, that all of them would affect future rate cases; is that correct, or did I misunderstand you?

A. I don't think I said that or meant to say that. There are some things that affect this case like -- and I said the Public Staff actually improved on some things that we had in there. There are other things that go to future cases, and I was just saying there's nothing in the future portion that limits anybody's investigation or ties the Commission's hands.

Q. Mr. Phillips, let's take a look at section 4 on page 4.

A. (Witness peruses document.)

I have that.

Q. And under that provision, it calls for the giveback of EDIT to be refunded to customers on a uniform sense kWh basis; do you see that?

A. I do.

Q. And that's a provision that would affect this case; isn't that right?

A. That is right.

Q. And Mr. Pirro reflected that in his schedules filed on August 24th; are you aware of that?

A. I am generally aware of that.

MS. DOWNEY: I don't have any further questions.

CHAIR MITCHELL: All right. Mr. Neal?

MR. NEAL: Thank you, Chair Mitchell. I think I don't have any questions at this time. Thank you.

CHAIR MITCHELL: All right. Redirect for your witness, Ms. Cress?

MR. SOMERS: Chair Mitchell, this is Bo Somers. Can I ask a question or two?

CHAIR MITCHELL: You may proceed, Mr. Somers.

MR. SOMERS: Thank you.

CROSS EXAMINATION BY MR. SOMERS:

Q. Good afternoon, Mr. Phillips. How are you?

A. I'm really good. How are you, Bo?

Q. I'm good. It's a pleasure to see you. Just a couple of questions.

Ms. Downey just asked you about section 4 of the settlement agreement between Duke Energy Carolinas and CIGFUR; do you still have that handy?

A. I do.

Q. So she asked you about the provision about the flowback of the EDIT rider and that it would be done on a uniform sense for kWh basis settlement agreement.

Did you hear Mr. Pirro's testimony earlier in the case?

A. I didn't. It was relayed to me by counsel.

Q. Well, I'll represent to you that Mr. Pirro testified that that was supported in his opinion, at least in part, because commercial and industrial customers are subsidizing residential customers currently, and this was a way to even it out.

Subject to my representation that that's a summary of what Mr. Pirro said on that point, what is your reaction to that?

A. I agree with that. Actually, I wanted to say I agree with Duke's proposal of reducing subsidies uniformly by 25 percent. I think that's a rational and good way to distribute any increase, because it would reduce all subsidies by 25 percent. But doing this part of the settlement and returning credits to ratepayers on a uniform sense per kilowatt hour would enhance that subsidy reduction, and I believe that's the way it was done in the DEP case.

Q. Last question for you. This may be the most important. Are our Cardinals going to catch the Cubs?

A. I say they are.

Q. Thank you. No further questions.

A. Thank you.

CHAIR MITCHELL: All right. Any additional cross examination for the witness?

(No response.)

CHAIR MITCHELL: All right. Redirect for the witness?

(Pause.)

MS. CRESS: John is sneaky. He'll put you back on mute real quick. Thank you, and I apologize. No redirect for me, thank you.

CHAIR MITCHELL: All right. Questions

from Commissioners, beginning with Brown-Bland.

COMMISSIONER BROWN-BLAND: Yes, I have one question.

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q. Mr. Phillips, in the CIGFUR partial settlement there in Section 3, there's a provision that provides -- and I'll just read it.

"With regard to allocating the deferred GIP costs amongst the customer classes in its next general rate case, DEC would propose to allocate these costs consistent with its distribution cost allocation methodologies as proposed in this docket. This includes use of the minimum system methodology and use of voltage dissipated allocation factors for distribution plant. Finally, assuming the Commission's approval," it says NCUC approval, "DEC agrees to use this methodology to allocate any GIP costs occurring during the three-year period for which it may seek cost recovery in future rate cases."

My question is, how is an agreement by the Company here to take a specific position or cost allocation in its next general rate case relevant or helpful to the Commission as evidence in this present rate case?

A. First, it's basically asking Duke to do what it's been doing and the Commission to approve what has been approved. Right now, Duke's -- for example, their OPT rates are by voltage level. So if you're a transmission customer, you're not allocated any primary or any secondary lines. If you're an OPT primary customer, you're not allocated any secondary lines.

So that is done in Duke's cost of service studies, and it is correct, it is cost causation. I think the Public Staff agrees with that. The minimum system, in my mind, I think the Public Staff agreed it's been in place for 47 years, and they just issued a report in March of '19 at the Commission's request that -- says that that approach is reasonable, and I didn't see any fault with it.

So I'm basically just asking Duke to keep doing what it's been doing and the Commission to take a look at it. And we're not telling the Commission what to do; we're just asking the Commission to take a look at what it's been doing and keep doing it.

Q. And is there -- I take it CIGFUR sees a value in the Commission's being aware that Duke will take these positions in the future? And where I'm coming from is the Supreme Court precedent for us here in

North Carolina is that a nonunanimous settlement is just some evidence that the Commission may consider. So just trying to figure out how this portion of the settlement is helpful to the Commission in what it has to set about to do here.

A. We understand that just because Duke proposes something, or CIGFUR, or anyone proposes something in the next general rate case, that the ultimate decision is with the Commission, and any party can write testimony or briefs and take a different position. We're just bringing out that we want Duke to continue this treatment that it's sound cost causation, and keep doing it.

Q. All right. I appreciate it. Thank you.

A. Thank you.

CHAIR MITCHELL: All right. Commissioner Gray?

COMMISSIONER GRAY: No questions.

CHAIR MITCHELL: Commissioner Clodfelter?

COMMISSIONER CLODFELTER: No questions.

CHAIR MITCHELL: Okay. Commissioner Duffley?

(No response.)

CHAIR MITCHELL: Commissioner Hughes?

COMMISSIONER HUGHES: No questions.

CHAIR MITCHELL: Commissioner McKissick?

COMMISSIONER McKISSICK: No questions.

CHAIR MITCHELL: All right. Questions on Commissioners' questions from Duke or any of the intervening parties? All right.

MR. NEAL: Chair Mitchell, this is David Neal.

CHAIR MITCHELL: All right, Mr. Neal.

MR. NEAL: Briefly.

EXAMINATION BY MR. NEAL:

Q. Mr. Phillips, good afternoon. I'm David Neal on behalf of the North Carolina Justice Center and related intervenors. You had a discussion with Commissioner Brown-Bland, you know, about the use of the minimum system method as it relates to GIP costs. So that's where I just wanted to go.

That you would -- it's your testimony that the minimum system is, I think you say, a generally accepted methodology; is that your position?

A. It is. I've said that this Commission's generally used it for 47 years.

Q. And you would agree, though, that this

Commission has never before been confronted with the question of whether or not to use the minimum system methodology when it comes to grid modernization projects or things like the grid improvement project, specifically; isn't that right?

A. I don't think they have, but it's just enhancing distribution costs. It's the same distribution system. You have the same voltages, you have the same theory of the minimum system.

Q. I understand the theory is the same, but just to be clear, the application of that theory to something like the Company's grid improvement plan has not been a question that this Commission has answered previously; isn't that right?

A. They asked for a study to be done, and it was completed last March. Other than that, I can't give you an example on future grid costs.

Q. And you would agree that classifying FERC accounts 364 to 368 on a demand basis, another way of referring to that would be the basic customer method?

A. Yes.

Q. And you would agree that there are a number of public utilities commissions around the country that have rejected the minimum system method and have, instead, ordered utilities to adopt the basic customer method in their cost of service studies?

A. There probably is, yes.

Q. In fact, you mentioned you used to work for Detroit Edison, do you know, are they allowed by the public service in Michigan to use the minimum system method?

A. I don't think so, but they use voltage and phases.

Q. And would you agree that, as a result of using the minimum distribution system is that more costs are allocated to small customers -- small customer classes such, as the residential class, and less costs are allocated to large customer classes, such as industrial or large commercial customers?

A. Well, when you say "small classes," you don't mean small number of customers because that's --

Q. No. Small users.

A. Yes. As a result of the minimum system, you allocate, and I think appropriately, a portion of those plant accounts by the number of customers. So classes that have a large number of customers would be allocated more.

MR. NEAL: I have no further questions.

Thank you, Chair Mitchell.

CHAIR MITCHELL: All right. Any additional questions on Commissioners' questions. Ms. Cress?

MS. CRESS: Yes, Chair Mitchell, I have a few.

EXAMINATION BY MS. CRESS:

Q. Mr. Phillips, can you explain this concept of rates that have in place different voltage levels?

A. Yes. I think it was mentioned on a previous day that the Commission ordered a redesign of Duke's rates, and I think there was a collaborative, maybe Mr. Floyd mentioned it, and it was difficult to get the parties together. But Duke's OPT rates, which have a large number of customers on them, are designated as OPT transmission, OPT primary, and OPT secondary.

Transmission primary and secondary are voltage designations. If you're served at the primary level -- and I believe the staff's report of March 19th -- March 2019 says this. If you're a large industrial customer served a transmission, you don't really use the distribution circuits, and substations, and levels because you take service at such a high voltage, you just don't use those facilities from Duke.

And within -- behind the meter or inside the fence, whatever terminology you're familiar with, the customer then does his own voltage transformation at his own expense and has transformers and circuits inside the fence.

So those rates don't allocate certain distribution costs to higher voltage customers, and that is completely appropriate. And I think most utilities in the country do that. It's easier to see for Duke because they have designated voltages on each of those rates.

Q. Now, you said that is an appropriate methodology. Why is that an appropriate methodology? Is there a name for it?

A. Well, it's -- you don't allocate costs to customers that they do not and cannot use. If you're a transmission customer, you cannot use a secondary line or a secondary transformer.

Q. And --

A. Cost causation.

Q. I apologize. Is there anything else you want to add before I --

A. No, that's it.

Q. Okay. And CIGFUR -- excuse me.

Do CIGFUR and the Public Staff agree, generally, that cost causation should be the principal form of determining cost allocation?

A. I believe so. I heard the staff's panel use that phrase a number of times, I think it was last Thursday, and we do agree on that. And I don't want to have us -- have anybody think that we don't get along with the Public Staff, because we probably resolve 90 percent of our issues once we're able to put them down on the table and talk about them.

Q. Is there anything inconsistent, in your opinion, as between the settlement provisions contained in CIGFUR's settlement and those contained in the Public Staff's?

A. I don't think so. I've read the Public Staff's settlement, and I think it's good, and it enhanced some of the things in the CIGFUR settlement.

Q. Is there anything pertaining to the winter peak that's different?

A. The Public Staff asked for studies regarding the winter peak and other peaks. In our settlement, we just asked for future studies for the summer peak, the winter peak, and two peaks, which would be the highest summer and the highest winter. We think it's not in our settlement, and we asked Duke to do those studies and then review those prior to the next case, and they agreed to do that. The Public Staff asked for other studies including those, and Duke agreed to do those.

Q. And you were about to say that you think, and then I think you --

A. Yeah. Because you asked about settlements. I would hope to see some recognition of the winter peak in this case, frankly, and I -- or if the winter peak is too abrupt of a change, at least do two peaks at the highest summer and the highest winter would be more appropriate.

Q. Why do you support the winter peak?

A. I have in my testimony, Duke did some exhaustive studies with some consultants. I forget if it was in combination with their 2016 integrated resource plan or just separate studies. They do to study, to plan their system, and in 2016 they formally announced that they were changing from a summer planning peak to a winter planning peak. Which means the winter peak is their most important peak.

It's the peak used to determine their reserve margin, which is how many plants they're going to build or how much capacity they're going to buy. And I think it's from 2016, these rates will be in effect to 2021. It's five years since they formally announced the winter peak is their planning peak, and I think it's time to start recognizing that for cost causation and cost allocation.

Q. Is there anything in the CIGFUR settlement that limits Commission discretion or its decision-making authority?

A. I don't think so. The Commission is the final word on anything, and I don't think there's anything in our settlement that ties the Commission's hands in any way.

Q. As between the regulatory assistance project, or RAP, and NARUC, which organization, in your opinion, publishes more reliable and bias-free materials?

MS. DOWNEY: Chair Mitchell, I don't recall Commissioner Brown-Bland asking questions on this subject.

CHAIR MITCHELL: All right. Ms. Cress, I'll remind you we're on questions on Commission's questions. So please tailor your questions to questions that Commissioner Brown-Bland asked.

MS. CRESS: Thank you, Chair Mitchell.

Q. To follow up on the conversation that you had with Commissioner Brown-Bland, which if I recall, had to do with cost allocation methodologies, and if those two organizations both have materials published related to cost allocation methodologies, which, in your opinion as between RAP and NARUC, would be more reliable and bias-free?

MS. DOWNEY: Same objection. Same objection.

CHAIR MITCHELL: All right. Ms. Cress, limit your questions to questions on Commissioner Brown-Bland's question.

MS. CRESS: I think that's everything from me. Thank you, Chair Mitchell.

CHAIR MITCHELL: All right. At this point, there's nothing further for the witness. Ms. Cress we will entertain a motion.

MS. CRESS: Yes, Chair Mitchell, thank you. I move that Mr. Phillips' testimony exhibits be moved into -- be entered into the record at this time.

CHAIR MITCHELL: All right. Hearing no objection, Ms. Cress, the motion is allowed.

(NP Exhibits 1 through 4 were admitted into evidence.)

CHAIR MITCHELL: Mr. Phillips, thank you for appearing before us today. You may step down.

At this point in time, we will take our afternoon break. We will go off the record. We will go back on at 3:25.

(At this time, a recess was taken from 3:11 p.m. to 3:27 p.m.)

CHAIR MITCHELL: At this point, let's go on the record. Are there any motions I need to entertain or any procedural matters to be addressed before we move into Duke's rebuttal case?

(No response.)

CHAIR MITCHELL: All right. Hearing none, let's see, we will proceed with Duke. Is that Mr. Jeffries? Mr. Marzo?

MR. ROBINSON: Yes, Chair Mitchell. This is Camal Robinson. Before we begin, now that we're moving into Duke's rebuttal case, just one procedural matter. Chair Mitchell, last week I believe the Commission agreed to excuse Mr. Erik Lioy from testifying during our rebuttal case. At this time the Company moves to enter the prefiled rebuttal testimony of Mr. Lioy consisting of 13 pages as attachment A into the record.

CHAIR MITCHELL: All right.

Mr. Robinson, hearing no objection to your testimony, the prefiled testimony to Mr. Lioy and the exhibit to that testimony will be admitted into the record of evidence in this proceeding.

(Lioy Attachment A was admitted into evidence.)

(Whereupon, the prefiled rebuttal testimony of Erik Lioy was copied into the record as if given orally from the stand.)

Q. PLEASE STATE YOUR NAME, BUSINESS AFFILIATION, BUSINESS ADDRESS AND CURRENT POSITION.

A. My name is Erik C. Lioy, I am a Dixon Hughes Goodman LLP (DHG) partner and member of DHG's Forensics and Valuation Services Practice. DHG is a top 20 accounting firm with over 2,000 partners and employees across the United States and the United Kingdom. DHG is headquartered in Charlotte, North Carolina at 4350 Congress St., Suite 900, Charlotte, NC 28209.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING YOUR TESTIMONY?

A. I am submitting this testimony before the North Carolina Utilities Commission ("Commission") on behalf of Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science in Business Administration (BSBA) from Duquesne University in 1993 and a Master of Business Administration (MBA) from the University of Pittsburgh in 2001. I am a Certified Public Accountant (CPA), licensed in the state of North Carolina. I also hold the following credentials: Certified in Financial Forensics (CFF), Certified Construction Auditor (CCA), Certified Global Management Accountant (CGMA) and Certified Fraud Examiner (CFE). I have over 25 years of professional experience performing a wide range of accounting and financial analyses in connection with litigation, regulatory and other matters. I have provided expert testimony at deposition and trial in federal and state courts and arbitrations. I have extensive experience preparing calculations and performing analyses using the time value of money concept. I have used this concept and its associated formulas beginning in my days as an undergraduate student, and continuing on a regular basis throughout my career. I estimate that I have performed time value of money calculations hundreds of times over the past 30 years. In preparing those calculations I have, as I have done in this matter, followed standard methodologies and referenced accepted treatise and professional guidance such as the American Institute of Certified Public Accountants (AICPA) Forensic and Valuation Services Practice Aid published in 2019 and titled *Discount Rates, Risk and Uncertainty in Economic Damages Calculations*.

A recap of my professional and educational background, including a list of my testimony in prior cases, is included as Attachment A to my testimony.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to respond to and comment upon the Supplemental Testimony ("Supplemental Testimony") of Steven C. Hart, a witness sponsored by the Office of the Attorney General ("AGO"). AGO Witness Hart's Supplemental Testimony was accepted by the Commission by its Order entered April 9, 2020. In his Supplemental Testimony, Witness Hart recommended certain disallowances be applied to the coal ash basin closure costs that DE Carolinas incurred during the period from January 1, 2018 through January 31, 2020 (the "Cost Recovery Period"), which it seeks to recover in this case. Specifically, Witness Hart performed an analysis, which he terms a "time value of money" analysis, and related calculations that purport to measure the alleged difference between the costs incurred during the Cost Recovery Period and costs which should have been incurred at various earlier points in time – 1989, 1995, 2003, and 2010. I demonstrate in my testimony that Witness Hart's calculations do not correctly utilize the time value of money methodology, and, therefore are flawed and not in accord with generally accepted financial practices.

Q. WHAT INFORMATION DID YOU REVIEW IN PREPARING YOUR TESTIMONY?

A. In addition to Witness Hart's Supplemental Testimony, I reviewed Witness Hart's direct testimony filed February 18, 2020 and a Microsoft Excel spreadsheet (named "DEC Cost Reduction Spreadsheet") submitted to the Company by the AGO on or about March 4, 2020. I understand the spreadsheet constitutes Witness Hart's workpapers, and were prepared by him in support of his Supplemental Testimony. I also was provided and have reviewed the transcript of Witness Hart's initial deposition taken March 2, 2020 ("Initial Deposition"), as well as the transcript of his deposition taken April 28, 2020 in both this Docket and the currently pending Duke Energy Progress, LLC rate case, Docket No. E-2, Sub 1219 (the "DEC/DEP Deposition"). I note that his workpapers for the DE Carolinas docket were referenced in the DEC/DEP Deposition as Exhibit 3.

Q. BASED ON YOUR ANALYSIS AND REVIEW, WHAT OPINIONS WERE YOU ABLE TO REACH REGARDING WITNESS HART'S SUPPLEMENTAL TESTIMONY?

A. It is my expert opinion that Witness Hart's proposed cost disallowance purporting to apply "time value of money" concepts is based on a flawed and incorrect analysis. His testimony and calculations demonstrate a fundamental misunderstanding of – and, therefore, a misapplication of – the concept of time value of money. His testimony is thus not in accord with standard and well-established methodologies, and, accordingly, his conclusions based on that analysis are flawed and unreliable.

Q. PLEASE EXPLAIN THE CONCEPT OF "TIME VALUE OF MONEY."

A. Time value of money is a financial concept used to value a sum of money at different points in time. The underlying premise of the concept is that when comparing sums of money over different periods of time, you need to factor in potential earning power of the money. Very simply, if you can earn 5% annual interest, a dollar today will be worth $1.05 in a year from now. The inverse is true, a dollar a year from now is a worth approximately $0.95 today. Time value of money therefore allows you to determine what a given sum of money would be worth at different points in time.

Q. IS THERE A MATHEMATICAL EQUATION USED TO DETERMINE THE TIME VALUE OF A SUM OF MONEY AT A DIFFERENT PERIOD IN TIME?

A. Yes. The mathematical equation for calculating the present value of a future dollar amount is:

$$PV = FV/(1+r)^N$$

Where PV = present value, FV = future value, r = rate and N=periods

Q. IF I TOLD YOU THAT I WANTED TO KNOW WHAT THE VALUE OF $100 TODAY WAS 20 YEARS AGO, YOU COULD CALCULATE THAT?

A. Yes, although the answer will vary according to the interest rate used. If you assume a 3% interest rate, $100 dollars in today's dollars is equal to approximately $55 in 2000 (20 years ago) dollars.

Q. ARE THOSE AMOUNTS, $55 20 YEARS AGO AND $100 TODAY, EQUAL?

A. Yes. Assuming a 3% interest rate, $55 dollars in 2000 dollars (20 years ago) is the equivalent of $100 in today's dollars. You can see this from the formula set out above:

$$\$55 = \$100/(1+.03)^{\wedge}20$$

Q. CAN YOU EXPLAIN WITNESS HART'S METHODOLOGY IN CONNECTION WITH HIS TIME VALUE OF MONEY CALCULATION?

A. Yes. Witness Hart applies a three-step process in his calculation. He first takes the cost of the coal ash compliance work performed by DE Carolinas in the period from January 1, 2018 through June 30, 2019 and makes certain adjustments to arrive at total cost of approximately $343 million, which he defines in his workpapers as the "Revised Cost." Although those costs were incurred between January 1, 2018 and June 30, 2019, he treated them as being incurred all in 2014, which is one of the errors in his work. Ignoring for the moment that error, in his second step Witness Hart then applies the time value of money concept to attempt to calculate what the Revised Cost was worth at various points in time in the past (specifically, 1989, 1995, 2003, and 2010) using an average inflation rate for each period. Finally, in his third step, Witness Hart compares the amount he calculates using his time value of money methodology at those various points in the past to the Revised Cost, subtracting in each instance the calculated amounts (expressed in prior period dollars) from the Revised Cost (expressed in 2014 dollars) to arrive at a portion of his recommended disallowance at those various points in time, a portion that he calls the "inflation cost." In short, he attempted to calculate some (but not all) of the costs incurred during the Cost Recovery Period, expressed the resulting figures in 1989, 1995, 2003, and 2010 dollars, and compared the amount for each of those years to the actual amount of costs incurred in 2018 and part of 2019 which he erroneously treats as having been incurred in 2014 dollars.

Q. CAN YOU PROVIDE US WITH AN EXAMPLE?

A. Yes, let's take for example Witness Hart's recommended "inflation cost" disallowance based upon his calculation for 1989. Working through his first two steps and based upon his workpapers and the testimony he provided in the

DEC/DEP Deposition, Witness Hart determined through trial and error that $171,500,000 (expressed in 1989 dollars) when future valued to 2014 would be worth $342,843,293.06, which he deemed close enough to the Revised Cost (approximately $343 million). In his third step, he then subtracts this 1989 calculated amount ($171.5 million) from the Revised Cost to arrive at what he refers to as "the inflation cost [calculated as of 1989] between the time DEC knew or should have known to take further action to address groundwater contamination at the basin." (Hart Supplemental Testimony, p. 126, lines 8-9). Thus, Witness Hart calculates the "inflation cost" as of 2014 to be approximately $171 million ($343 million - $172 million = $171 million).

Q. WHAT DOES THAT $171 MILLION AMOUNT REPRESENT?

A. That difference ($171 million dollars) is simply the arithmetic difference between the Revised Cost (or, in actuality, a sum derived through trial and error to be "close enough" to the Revised Cost) expressed in 2014 dollars and the Revised Cost (or, again, in actuality a sum derived through trial and error to be "close enough" to the Revised Cost) expressed in 1989 dollars. The Revised Cost (or, once again, in actuality a sum "close enough" to the Revised Cost as indicated above) is simply inflation adjusted using the interest rate used by Witness Hart, which appears to be the Consumer Price Index or CPI.

Q. DOES WITNESS HART'S TIME VALUE OF MONEY ANALYSIS CORRECTLY UTILIZE TIME VALUE OF MONEY METHODOLOGY?

A. No. The point of calculating the time value of money is to make things equivalent, so that a comparison of costs at different time periods can be made using constant dollars. Under his calculation, $343 million in today's dollars (again ignoring Witness Hart's error of using 2014 instead of "today") is equivalent to $172 million in 1989 dollars. But to assert, as Witness Hart does, that there is a "difference" between these figures actually results from an apples (1989 dollars) to oranges ("today's" – although actually 2014 – dollars) comparison. In fact, these amounts are equivalent, just expressed at different points in time.

A correct apples-to-apples time value of money analysis would determine that those amounts, compared in constant dollars, are equivalent. Witness Hart's analysis actually demonstrates this – in constant dollars, the difference between the cost of the work had it been performed in 1989 ($172 million in 1989 dollars, or its equivalent in today's dollars, $343 million) and the Revised Cost is ZERO.

Q. WOULD THE SAME RESULT FOLLOW USING WITNESS HART'S OTHER TIME PERIODS?

A. Yes. For each of his other time periods (1995, 2003, and 2010) the difference, in constant dollars, of the cost of the work, had it been performed as of those earlier periods, and the Revised Cost is also ZERO. This is because, as demonstrated by his calculations, the cost of work at those earlier periods is the equivalent of the Revised Cost, but is simply expressed in earlier period dollars.

Q. DO YOU UNDERSTAND WHAT WITNESS HART WAS TRYING TO ACCOMPLISH IN HIS TIME VALUE OF MONEY CALCULATION?

A. It is my understanding based on reading his written testimony and deposition transcripts that he was attempting to quantify the amount DE Carolinas would have spent as of the earlier time periods in his analysis (1989, 1995, 2003, and 2010) in an attempt, however flawed, to quantify alleged imprudently incurred costs.

Q. DID WITNESS HART ACCOMPLISH THAT GOAL THROUGH HIS USE OF THE TIME VALUE OF MONEY CALCULATION YOU DESCRIBED?

A. No. In fact, as I demonstrate above, the correct result of calculations when applying (instead of misapplying) time value of money methodology is that there is no difference between the Revised Cost expressed in "today's" (or 2014) dollars and the Revised Cost expressed in earlier period dollars.

All Witness Hart did is make a mathematical calculation by subtracting the Revised Cost (expressed in earlier period dollars) from the Revised Cost (expressed in "today's" – actually 2014 – dollars). At his deposition Witness Hart indicated that he "didn't know of" any standard texts or peer reviewed journals that supported his application of the time value of money concept in this fashion (DEC/DEP Deposition, p. 76), indicating that it was just subtraction. But is also clear from his deposition that Witness Hart actually understands that the time value of money concept is designed to make equivalent sums of money expressed in different period values. For example, he indicated that he had on a number of occasions discounted future damages or costs to be incurred back to present value so as to make a claimant whole:

> A: …So we are looking at discounting the cost for its future value if you receive a lump sum payment today for the remediation cost.
>
> Q: In order to ensure that the claimant receives that future value in a lump sum today, correct?
>
> Q: Correct.

(DEC/DEP Deposition, pp. 55-56). Proper application of the time value of money concept is premised on making values equivalent even though expressed at different times, in order to account for inflation or the earning power of money. Witness Hart's "just subtraction" method, for which he indicates no support, misapplies the time value of money concept.

Moreover, there are a number of factors that would need to be considered to determine what DE Carolinas would have spent in 1989 (or as of any of the other earlier time periods). For example, to fully evaluate work that would or could have been done in, say, 1989 would require the evaluator to take into account different applicable laws and regulations in 1989 as compared to today, and different technologies, means and methods available in 1989 as compared to today, among other potential differences. Witness Hart does not even attempt to do this – indeed, he indicates that doing so presents many difficulties, including the difficulty "at this point in time to retroactively determine what costs would have been incurred 10 or more years ago."

(Supplemental Testimony, p. 28, line 22 – p. 129, line 1). I agree – Witness Hart's calculation is purely speculative, not based on reasonable assumptions, and, accordingly, wholly unreliable.

Q. YOU HAVE EXPLAINED IN DETAIL HOW WITNESS HART ERRONEOUSLY USED THE TIME VALUE OF MONEY METHODOLOGY IN ARRIVING AT HIS CONCLUSIONS. WITHOUT REGARD TO THE METHODOLOGICAL ISSUES PREVIOUSLY DISCUSSED, DID YOU NOTE ANY OTHER ERRORS WITH HIS CALCULATIONS?

A. Yes. First, it is important to note that I have not been asked to, nor have I validated the data used by Witness Hart in his calculations. I simply took that data at face value, inasmuch as it is very clear that he has simply misapplied the time value of money concept.

That being said, Witness Hart made a number of errors. As a threshold matter, he did not actually calculate the time value of money correctly, but, as he testified to, used a trial and error method to reach an approximation of the actual amount. In addition, he takes costs incurred over a period of time in 2018 and 2019 and treats them as being incurred on a single day, December 31, 2014. Witness Hart then discounts them back to January 1 of each specific year. By treating costs in 2018 and 2019 as occurring in 2014, he completely ignores the time value of money concept. Further, his approach of assuming all costs (hundreds of millions of dollars-worth) occurred on a single day for purposes of his calculation defies reason and normal convention where the costs are incurred and spread out over multiple years. Taking these factors into consideration, even if one were to accept his methodology (which I have explained does not make sense) his calculations are wholly unreliable, not prepared in accordance with normal conventions, and wholly speculative.

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL REBUTTAL TESTIMONY?

A. Yes.

MR. ROBINSON: Thank you.

CHAIR MITCHELL: All right. Any additional procedural matters?

(No response.)

CHAIR MITCHELL: All right. Duke, you may call your witnesses.

MR. JEFFRIES: Chair Mitchell, this is Jim Jeffries on behalf of Duke Energy Carolinas. Myself and Mr. Marzo will be handling Duke's first rebuttal testimony, and calls Mr. David Doss and Mr. John Spanos to the stand.

CHAIR MITCHELL: All right. Thank you, Mr. Jeffries. There's Mr. Spanos, and there's Mr. Doss.

Whereupon,

DAVID L. DOSS, JR. AND JOHN J. SPANOS,

having first been duly affirmed, were examined

and testified as follows:

CHAIR MITCHELL: All right. Mr. Jeffries, Mr. Marzo, you all may proceed.

MR. JEFFRIES: Thank you, Chair Mitchell. I will begin with Mr. Spanos.

DIRECT EXAMINATION BY MR. JEFFRIES:

Q. Mr. Spanos, welcome back for your rebuttal round.

Could you state your name and business address for the record, please?

A. (John J. Spanos) John J. Spanos, 207 Seventh Avenue, Camp Hill, Pennsylvania 17011.

Q. Mr. Spanos, you're the same John Spanos that prefiled rebuttal testimony in this proceeding on March 4, 2020, consisting of 39 pages; is that correct?

A. That is correct.

Q. And was that testimony prepared by you or under your direction?

A. Yes, it was.

Q. Do you have any corrections to that testimony as filed?

A. I do not.

Q. Mr. Spanos, if I asked you the same questions that are set forth in your prefiled rebuttal testimony while you were on the stand today, would your answers be the same?

A. Yes, they would.

Q. And, Mr. Spanos, have you also prepared a summary of your rebuttal testimony?

A. Yes, I have.

MR. JEFFRIES: And, Chair Mitchell, I

will note for the record that that summary has been distributed to the parties and filed with the Commission, I believe. Based on Mr. Spanos' answers the last few minutes, we would move that his prefiled rebuttal testimony and summary be entered into the record as if given orally from the stand.

CHAIR MITCHELL: All right. Hearing no objection to your motion, Mr. Spanos' prefiled rebuttal testimony and his rebuttal testimony summary will be copied into the record as if given orally from the stand.

(Whereupon, the prefiled rebuttal testimony and summary of testimony of John J. Spanos was copied into the record as if given orally from the stand.)

I. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John J. Spanos and my business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Gannett Fleming Valuation and Rate Consultants, LLC as President.

Q. ARE YOU THE SAME JOHN J. SPANOS THAT PREVIOUSLY PROVIDED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My rebuttal testimony addresses the testimonies of Commission Public Staff witnesses Roxie McCullar and Michelle M. Boswell regarding Public Staff's proposed adjustments to the depreciation rates submitted by Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company") in this case. I also respond to Public Staff witness Maness' testimony around the issue of whether prior depreciation studies included costs for the closure of coal ash facilities in net salvage percentages.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. My testimony responds to the depreciation related proposals of the Public Staff witnesses mentioned above. In some instances, Ms. McCullar's proposals are not consistent with the concepts decided by the Commission in Docket No. E-7, Sub 1146. Specifically, Ms. McCullar's proposals for net salvage are not established in a manner that will recover the full amount of future net salvage costs. Additionally, Ms. McCullar proposed to extend the life of AMI Meters, despite the fact that none of the factors affecting the life of these assets have changed since the Commission accepted a 15-year average service life in Docket No. E-7, Sub 1146.

Additionally, Public Staff has failed to incorporate new information and data to update the estimates for certain accounts in the Company's current rate case from those adopted by the Commission the Company's last rate case. In these instances – specifically the interim net salvage for production plant accounts and the life spans of Allen and Cliffside Unit 6 – additional data and information since the last study provides support for changes to the currently approved depreciation parameters. Thus, unlike many of the changes proposed by Ms. McCullar in which she proposes to change depreciation concepts, the changes I have recommended are based on additional data – not a change in concepts.

In addition to the issues I address in my testimony, the Depreciation Study incorporates the full decommissioning cost values established by Mr. Kopp, Burns and McDonnell, from the last rate case which justifies the most appropriate contingency component in the decommissioning estimates for the Company's power plants.[1] Therefore, the full decommissioning estimate in the Depreciation Study in this case incorporates the 20% contingency component.

III. NET SALVAGE

A. Introduction

Q. WHAT IS NET SALVAGE?

A. Net salvage, as used in depreciation, is defined as gross salvage less cost of removal. When an asset is retired it may have scrap or reuse value, which is gross salvage. There is also a cost to retire the asset. For example, the retirement of a distribution pole typically requires a multiple person crew and heavy equipment to remove the pole from the ground and cut the pole for disposal. There also may be disposal costs for the pole. If the costs to remove the equipment from service are greater than the salvage value of the asset, then the net salvage is referred to as negative net salvage.

Q. SHOULD NET SALVAGE BE DETERMINED AS AN ESTIMATE OF THE COST TO RETIRE AN ASSET TODAY OR AS THE FUTURE COST TO RETIRE AN ASSET AT THE TIME OF ITS EXPECTED RETIREMENT?

A. Net salvage is estimated as the cost to retire an asset, net of any gross salvage, at the time the asset is expected to be retired. Net salvage is not estimated as today's cost to retire an asset. The reason for this is that if today's costs were estimated,

[1] See *Rebuttal Testimony of Jeffrey T. Kopp for Duke Energy Carolinas*, Docket No. E-7, Sub 1146, pp. 11-15 (February 6, 2018).

then the application of straight-line depreciation would typically fail to recover the full cost to retire the asset because costs tend to increase over time.

Q. DID THE COMMISSION RULE ON THIS CONCEPT IN DOCKET NO. 7, SUB 1146?

A. Yes. In that docket, Ms. McCullar challenged the inclusion of the full future net salvage cost in depreciation and instead proposed to only include estimates of net salvage costs at current cost levels. The Commission determined that the full future net salvage cost should be included, stating that:

> Considering all the evidence, the Commission finds and concludes that the escalation of terminal net salvage cost and the use of the straight-line method of depreciation in determining escalation as performed in the DEC Decommissioning Study is just and reasonable, appropriate for use in this case, and is adopted.[2]

The Commission also concluded that estimating net salvage as the future costs to retire an asset is consistent with authoritative texts and depreciation practices:

> The testimony and evidence presented in this case demonstrates that authoritative texts and sound depreciation practices support escalating terminal net salvage costs to the date that the costs are expected to be incurred.[3]

As an example, the Commission cited to the National Association of Regulatory Utility Commissioners' ("NARUC") *Public Utility Depreciation Practices:*

> Under presently accepted concepts, the amount of depreciation to be accrued over the life of an asset is its original cost less net salvage. <u>Net salvage is the difference between gross salvage that</u>

[2] Sub 1146 Order at p. 175.
[3] Sub 1146 Order at p. 174

> <u>will be realized when the asset is disposed of and the costs of retiring it.</u>[4]

Q. ARE STAFF'S NET SALVAGE PROPOSALS IN THE INSTANT CASE CONSISTENT WITH THE COMMISSION'S ORDER IN DOCKET NO. E-7, SUB 1146?

A. Yes and no. Staff's proposed net salvage estimates for decommissioning the Company's power plants are escalated to the date of retirement, consistent with Commission order.[5] However, her actual proposal notwithstanding, Ms. McCullar again discusses this concept in her testimony and appears to argue instead for only escalating costs to the year 2023.[6] As I have discussed, the Commission has already reviewed this concept in DE Carolinas' previous case, did not find Ms. McCullar's arguments persuasive, and found that the Company's approach is appropriate.

While Ms. McCullar's actual proposed depreciation rates incorporate the escalation concept consistent with the Commission's Decision, she does make one proposal for net salvage for distribution plant that is not consistent with the Commission's decision in Docket No. E.7 Sub 1146. Ms. McCullar proposes a less negative net salvage estimate for Account 366, Underground Conduit. While overall her proposal for this account does not have as significant an impact as her proposals for other accounts, she does not provide any statistical basis for her

[4] Sub 1146 Order at p. 174, citing NARUC at p. 18. (Emphasis added in Commission order)
[5] McCullar at 15:1-7.
[6] McCullar at 20-21.

proposal other than to compare her results to the Company's recently recorded costs. Additionally, she supports her proposal in testimony by arguing against including future inflation in net salvage estimates. As I have discussed, the Commission has already decided against Ms. McCullar's opinion on this concept and has found that the Company's approach is widely supported.

Q. HAS THE COMMISSION PREVIOUSLY RECOGNIZED PROBLEMS WITH MS. MCCULLAR'S APPROACH TO ESTIMATING NET SALVAGE?

A. Yes. In addition to recognizing that the Company's approach is widely accepted and consistent with authoritative texts and depreciation practices, the Commission observed that Ms. McCullar's approach has previously found to be deficient:

> [O]ther state utility commissions have rejected witness McCullar's alternative approach as unsupported. For example, in a recent case before the Washington Utilities and Transportation Commission (WTC), witness McCullar advanced similar arguments against the escalation of terminal net salvage costs along with other recommendation related to depreciation. In rejecting the recommendation, the WTC noted that Public Counsel and witness McCullar provided no response to the critique that witness McCullar's approaches were not supported by authoritative accounting literature. The WTC found witness McCullar's net salvage proposal "[v]ague in its methodology, not supported by authoritative accounting literature, and supported by unwarranted assumptions."[7]

Q. HOW IS NET SALVAGE ESTIMATED IN A DEPRECIATION STUDY?

A. Net salvage estimates are expressed as a percentage of the original cost retired. For example, if an account has a net salvage estimate of negative 50%, then a

[7] Order at 175. Footnotes omitted.

$1,000 asset would be expected to, on average, cost $500 to retire, net of any gross salvage. The method of determining the estimated net salvage percent depends on the type of property. For power plants, the estimate is typically based on a decommissioning study, with additional net salvage incorporated for interim retirements (i.e., those that occur prior to the final retirement of the plant). These costs are typically estimates of the cost to retire a facility today, and therefore need to be adjusted to estimate the cost that will be incurred in the future when the plant is actually retired.

For mass property accounts such as those for transmission and distribution plant, net salvage estimates are based in part on statistical analyses of historical net salvage data. In this analysis, net salvage (as well as its components of gross salvage and cost of removal) are expressed as a percentage of retirements. This approach, which is widely accepted in the industry and supported by depreciation textbooks, is referred to as the traditional method.

B. The Company's Approach for Net Salvage is Consistent with Commission Precedent and Depreciation Authorities

Q. ON PAGES 30 AND 31 OF HER TESTIMONY MS. MCCULLAR CITES TO DECISIONS FROM FOUR STATE COMMISSIONS AND THE DISTRICT OF COLUMBIA THAT SHE CLAIMS "ADOPTED FUTURE NET SALVAGE PERCENT THAT RECOGNIZES THE TIME VALUE OF COST OF REMOVAL DUE TO INFLATION." DO THE ORDERS CITED BY MS. MCCULLAR SUPPORT THAT HER PROPOSED APPROACH IS WIDELY ACCEPTED?

A. No. The existence of a handful of instances in which different approaches were used does not disprove that the Company's approach for net salvage is used by the vast majority of jurisdictions. Additionally, two of the state jurisdictions cited by Ms. McCullar do not use the type of approach claimed by Ms. McCullar. Rather than adopting future net salvage estimates that "recognize the time value of cost of removal due to inflation," New Jersey and Pennsylvania do not include future net salvage estimates in depreciation.[8] Instead, in these jurisdictions net salvage is recovered either as it is incurred or after the costs are incurred.

[8] That this is the case can be seen in the plain language of the citations to New Jersey and Pennsylvania on pages 30 and 31 of Ms. McCullar's testimony.

Q. ON PAGES 21 AND 22 OF HER TESTIMONY, MS. MCCULLAR ALSO CITES TO FOUR CASES THAT SHE CLAIMS "REMOVED THE ESCALATION OF ESTIMATED FUTURE TERMINAL NET SALVAGE COSTS." DO THESE ORDERS PROVIDE JUSTIFICATION FOR THE COMMISSION REVERSING ITS DECISION IN DOCKET NO. E-7, SUB 1146?

A. No. None of these cases change that the Commission has already decided this issue in the Company's previous case. Additionally, of the four cases Ms. McCullar cites, one is a settlement agreement and two are from more than a decade ago (one is from 2005 and one is from 2007). Since that time, a number of power plants have been retired and decommissioned – many prior to being fully depreciated and without full recovery of terminal net salvage. This has supported the need to properly incorporate future net salvage costs in depreciation rates for generation facilities. Accordingly, the cases Ms. McCullar cites are not particularly relevant to the instant case, in particular because the Commission has already found the Company's approach to be appropriate.

Q. HAS THE COMMISSION ALSO FOUND THAT THE COMPANY'S APPROACH TO NET SALVAGE IS USED BY THE VAST MAJORITY OF REGULATORY JURISDICTIONS?

A. Yes. In the Decision in Docket No. E-7 Sub 1146, which was issued in June of 2018, the Commission recognized that:

> The fact is the vast majority of jurisdictions use a method for net salvage in which future net salvage is estimated at its future cost and recovered through straight-line depreciation (also known as the traditional method). Approximately 46 out of 50 jurisdictions recover future costs using the straight-line depreciation method.[9]

While Ms. McCullar cites to a handful of cases she claims to support her approach to net salvage, these are in the minority and the vast majority of jurisdictions use the Company's approach.

Q. IS RECOVERING THE FUTURE COST OF NET SALVAGE CONSISTENT WITH THE UNIFORM SYSTEM OF ACCOUNTS?

A. Yes. The Uniform System of Accounts ("USOA") specifically defines net salvage as follows:

> 19. Net salvage value means the salvage value of property retired less the cost of removal.

Cost of removal is defined as:

> 10. Cost of removal means the cost of demolishing, dismantling, tearing down or otherwise removing electric plant, including the cost of transportation and handling incidental thereto. It does not include the cost of removal activities associated with asset retirement obligations that are capitalized as part of the tangible long-lived assets that give rise to the obligation. (See General Instruction 25).

Finally, cost is defined as (emphasis added):

> 9. Cost means the <u>amount of money actually paid</u> for property or services. When the consideration given is other

[9] Order at 175

> than cash in a purchase and sale transaction, as distinguished from a transaction involving the issuance of common stock in a merger or a pooling of interest, the value of such consideration shall be determined on a cash basis.

Read together, these definitions make clear that the USOA specifies that cost of removal, which as part of net salvage must be recovered through depreciation expense, is the actual amount that is paid at the time of the transaction. Because net salvage will occur in the future, it is an estimate of the future cost that must be included in depreciation rates.

Q. HAS FERC CONFIRMED THAT THE ESTIMATED FUTURE NET SALVAGE COST SHOULD BE INCLUDED IN DEPRECIATION?

A. Yes. FERC has clarified that not only should future net salvage estimates include future inflation (which are recovered on a straight-line basis rather than a present value basis), but that failing to include future inflation results in intergenerational inequity:

> We affirm the Presiding Judge's finding that Entergy has demonstrated that the decommissioning cost estimate should be escalated three percent annually to the retirement dates estimated for Entergy Arkansas' steam production units. Based on the record before us, we agree with the Presiding Judge that it is reasonable for the current decommissioning costs to be inflated to reflect future costs of decommissioning at the time of retirement in order to avoid intergenerational inequities between current and future ratepayers.[10]

Q. ON PAGES 27 AND 28 OF HER TESTIMONY, MS. MCCULLAR CITES TO NARUC's *PUBLIC UTILITY DEPRECIATION PRACTICES* AND

[10] 142 FERC ¶ 61,022 at P 175. (Emphasis added)

WOLF AND FITCH'S *DEPRECIATION SYSTEMS*. DO THESE TEXTS SUPPORT HER APPROACH FOR NET SALVAGE?

A. No. As discussed previously, the Commission found in DEC's previous rate case that NARUC supported the Company's approach for net salvage. Ms. McCullar's citations do not dispute this point and a more comprehensive review demonstrates that neither text supports the type of analysis she performed. Further, her discussion of these texts does not put the quotes that she cites in the proper context. For example, Ms. McCullar presents a quote that, without context, may give the appearance that NARUC believes the inclusion of future net salvage costs is problematic due to the impact of inflation. The portion she cites reads:

> The sensitivity of salvage and cost of retirement to the age of the property retired is also troublesome. Due to inflation and other factors, there is a tendency for costs of retirement, typically labor, to increase more rapidly than material prices.[11]

However, the very next sentences on page 19 of NARUC make clear that the future costs, including the impact of inflation, should be included in depreciation:

> In an increasing number of instances, the average net salvage is estimated to be a large negative number when expressed as a percentage of original cost, sometimes in excess of negative 100%. This may look unrealistic but is appropriate and necessary so that the required cost allocation occurs.[12]

[11] McCullar at 28:8-12, citing *Public Utility Depreciation Practices* at 19.
[12] *Public Utility Depreciation Practices* at 19.

Q. PLEASE EXPLAIN FURTHER THAT NARUC AND WOLF AND FITCH SUPPORT THAT THE NET SALVAGE INCLUDED IN DEPRECIATION SHOULD REPRESENT FUTURE, NOT CURRENT, COSTS.

A. In the passage cited by the Commission in Docket No. E-7, Sub 1146, NARUC explains the following:

> [U]nder presently accepted concepts, the amount of depreciation to be accrued over the life of an asset is its original cost less net salvage. <u>Net salvage is difference between the gross salvage that will be realized when the asset is disposed of and the cost of retiring it</u>.[13] (Emphasis added)

Wolf and Fitch also explain that net salvage should be included in depreciation and that it should be recognized as a future cost:

> The matching principle specifies that all cost incurred to produce a service should be matched against the revenue produced. Estimated future costs of retiring an asset currently in service must be accrued and allocated as part of the current expenses.[14]

In the same paragraph, the authors are clear that inflation is part of the future cost of net salvage, stating that:

> Negative salvage is a common occurrence. With inflation, the cost of retiring long-lived property, such as a water main, may exceed the original installed cost.[15]

Wolf and Fitch then address intergenerational equity, stating:

> The accounting treatment of these future costs is clear. They are part of the current cost of using the asset and must be

[13] NARUC Manual, p. 18.
[14] Wolf and Fitch, p. 7.
[15] Ibid, p. 8.

> matched against revenue. While the current consumers would say they should not pay for future costs, it would be unfair to the future users if these costs were postponed.[16]

Finally, Wolf and Fitch argue against a present value or current value concept. The authors note that:

> Some say that although the current consumers should pay for the future costs, the future value of the payments, calculated at some reasonable interest rate, should equal the retirement cost. Studies show that the salvage is often "more negative" than forecasters had predicted.[17]

They also state that:

> In the accounting framework, depreciation is defined as an allocation process, *not* a valuation process.[18] (Emphasis in original)

Q. DO NARUC AND WOLF AND FITCH EXPLAIN HOW NET SALVAGE IS ESTIMATED FOR MASS PROPERTY ACCOUNTS?

A. Yes. NARUC states that "net salvage is expressed as a percentage of plant retired by dividing the dollars of net salvage by the dollars of original cost of plant retired."[19] This is the method of analysis used in the Company's depreciation study.

Wolf and Fitch also explain that net salvage is expressed as a percentage of the original cost of plant retired, noting "the SR [Salvage Ratio] is the salvage

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[16] Ibid, p. 8.
[17] Ibid, p. 4.
[18] Ibid, p. 4.
[9] NARUC Manual, p. 18.

divided by the original cost of the retirements and usually is expressed as a percentage."[20]

Q. WHAT ANALYTICAL METHOD DOES MS. MCCULLAR PROVIDE TO SUPPORT HER ESTIMATE FOR ACCOUNT 366, UNDERGROUND CONDUIT?

A. The only analysis Ms. McCullar provides in support of her proposal is a comparison of the net salvage costs included in the proposed depreciation rates to the amount of net salvage the Company has incurred, on average, over the past five years.[21]

Q. DOES THE TYPE OF ANALYSIS PROVIDED BY MS. MCCULLAR PROVIDE A REASONABLE BASIS TO ESTIMATE FUTURE NET SALVAGE?

A. No. The premise of the type of analysis performed by Ms. McCullar is that depreciation accruals for net salvage should be similar to, if not the same as, the net salvage occurred each year. This premise is inconsistent with the goal of depreciation of recovering capital costs, including net salvage, over the service life

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[10] Wolf and Fitch, p. 261. Note that, in this context, Wolf and Fitch use the term "salvage" to mean "net salvage." In addition to describing the traditional method, Wolf and Fitch also present more detailed analysis of net salvage by age. The intent of this more detailed analysis is to recognize the impact of age and inflation on the traditional method of net salvage analysis. In the aged net salvage analysis described by Wolf and Fitch, net salvage is first converted to constant dollars. Then, the level of inflation that will occur over the full service life of each asset is calculated (which is often longer than the age of retirements in the historical net salvage data). The result of this more detailed analysis is typically more negative net salvage estimates than would occur from the traditional method.

[21] McCullar at 33.

of the related assets. Because net salvage costs are future costs, the recovery of these costs through depreciation will occur prior to net salvage costs being incurred and, as a result, depreciation accruals for net salvage will often exceed incurred net salvage.

It is also important to understand that net salvage recorded in a given year is a function of the amount of property retired. For example, it would cost more to retire 1,000 poles in a given year than to retire 100 poles. By expressing historical net salvage as a percentage of historical retirements, the method of net salvage analysis I have used to estimate net salvage in the depreciation study, which is the industry standard method for estimating future net salvage, recognizes this relationship between net salvage and retirements. Ms. McCullar's analysis does not recognize this important relationship.

Q. DO ANY AUTHORITATIVE DEPRECIATION TEXTS SUPPORT MS. MCCULLAR'S ANALYSIS?

A. No. I am not familiar with any, and Ms. McCullar has not provided any citations that support comparing the dollar level of net salvage included in depreciation rates to the dollar level of net salvage incurred.

C. Public Staff's Interim Net Salvage Proposal for Other Production Plants

Q. WHAT HAVE YOU PROPOSED AS AN INTERIM NET SALVAGE ESTIMATE FOR OTHER PRODUCTION ACCOUNTS?

A. In the depreciation study, I have recommended an interim net salvage percent of negative six percent for other production accounts, with the exception of rotable parts at combined cycle plants.

Q. THE COMMISSION ADOPTED AN ESTIMATE OF ZERO PERCENT FOR THESE ACCOUNTS IN THE COMPANY'S PREVIOUS RATE CASE. DOES THE DATA SINCE THAT CASE SUPPORT A NEGATIVE NET SALVAGE ESTIMATE?

A. Yes. The data since that study indicates a negative net salvage estimate. I also note that in DE Carolina's previous case, the Commission indicated that the estimates for these accounts can be revisited. In Docket No. E-7 Sub 1146, the Commission found that:

> Based on the evidence discussed above and the entire record in this case, the Commission finds that the Public Staff's proposal to set an interim net salvage percentage of 0 for Accounts 342, 343, 344, 345, and 346 is reasonable. Historical data show that using a negative value, as was previously set, has resulted in DEC overcollecting its costs. It would be inequitable to charge customers for costs that the utility is unlikely to incur. As discussed previously, the Company has stated publicly that it plans to file multiple rate cases between 2019 and 2023, and therefore, this issue can be reexamined in the next base rate case.[22]

[22] Sub 1146 Order at p. 177.

In the two years since the previous case, the net salvage for each of these accounts has been negative. As a result, the use of a net salvage estimate of zero has resulted in DEC under-collecting these costs.

Q. DOES THE RECENT DATA PROVIDE ADDITIONAL SUPPORT FOR A NEGATIVE NET SALVAGE ESTIMATE FOR THESE ACCOUNTS?

A. Yes. In the previous case I explained that, while there had been positive net salvage in previous years in the aggregate for these other production accounts, this was likely primarily due to positive net salvage for rotable parts. The other accounts in the other production functions should be expected to experience negative net salvage, as is typically the case for other utilities for these accounts.

Data since the last rate case supports this concept. In the two years since the previous study, 2017 and 2018, the Company has incurred $1,450,843 in cost of removal and received $45,163 in gross salvage. Thus, the data since the last study supports a negative net salvage estimate for these accounts, since cost of removal has exceeded gross salvage. Additionally, because interim net salvage has been zero for these accounts, these costs were not recovered over their service lives.

The recent data supports the concept that negative net salvage should be expected for these accounts. Based on the types of assets in these accounts, I expect that net salvage will, on average, continue to be negative going forward.

Q. PLEASE EXPLAIN FURTHER WHY YOU EXPECT NEGATIVE NET SALVAGE FOR THESE ACCOUNTS.

A. Modern combined cycle generating plants are comprised of one or more combustion turbines and a steam turbine that uses heat from the combustion turbine process to generate additional electricity. The combustion turbines are highly efficient modern machines that require the regular replacement and refurbishment of various components, including assets such as turbine blades and transition nozzles. In DEC's previous depreciation study, these parts were grouped into a separate subaccount for "rotable parts." Because these components of the plants are regularly refurbished, they typically experience positive net salvage.

However, the net salvage for rotable parts differs significantly from other components of a combined cycle plant, which typically experience negative net salvage. When replacing assets such as pumps, piping and structural components, utilities typically incur a cost to retire the assets that exceeds any scrap, as these assets cannot be refurbished and reused like rotable parts. As a result, these components of combined cycle plants typically experience negative net salvage.

Q. IN THE PREVIOUS DEPRECIATION STUDY, WAS THE POSITIVE NET SALVAGE FOR ROTABLE PARTS ABLE TO BE SEPARATELY IDENTIFIED?

A. Yes and no. While the previous depreciation study did provide a separate net salvage analysis for rotable parts, these parts had not been accounted separately from the balance of Account 343, Prime Movers. As a result, the specific demarcation between rotable parts and other components in the historical data was not as clear as will be the case going forward. In the time since the previous study, during which time Duke has begun to account for rotable parts in a separate subaccount, the non-rotable parts accounts have experienced negative net salvage, which is typical for these types of assets and should be expected going forward.

IV. <u>SERVICE LIFE OF AMI METERS</u>

Q. HAVE ANY PARTIES MADE ANY RECOMMENDATIONS RELATED TO THE COMPANY'S AMI METER DEPLOYMENT?

A. Yes. Ms. McCullar recommends a different average service life for the new AMI meters than the 15-year average service life approved in Docket No. E-7, Sub 1146.

Q. WHAT AVERAGE SERVICE LIFE WAS USED FOR METERS IN THE COMPANY'S PREVIOUS DEPRECIATION STUDY?

A. A 15-year average service life was used, which is the same as used in the depreciation study filed in the instant case.

Q. WAS THE 15-YEAR AVERAGE SERVICE LIFE ADOPTED BY THE COMMISSION?

A. Yes. While Ms. McCullar proposed a 17-year average service life in Docket No. E-7, Sub 1146, the Commission adopted the 15-year average service life proposed by the Company. On page 178 of the order in that docket, the Commission stated that the depreciation rates proposed by the Company were adopted, with the exception of certain depreciation rates discussed in the decision. Because the 15-

year average service life for AMI meters was not specifically identified and modified in the Commission's decision, the 15-year average service life for AMI meters was adopted by the Commission. Additionally, the Company's cost-benefit analysis in that case for AMI meters was based on a 15-year life and the Commission had specifically requested that such analysis included the "cost of replacing AMI meters at the end of their 15-year useful life."[23]

Q. WHAT HAVE YOU RECOMMENDED FOR AMI METERS IN THE INSTANT CASE?

A. I have recommended to continue to use the 15-S2.5 survivor curve currently approved for DE Carolinas. This estimate is consistent with the manufacturer recommendation for the physical life of AMI meters, but also considers that meters are retired for other reasons, such as damage or obsolescence.

Q. WHAT HAS PUBLIC STAFF PROPOSED?

A. Public Staff has proposed an average service life of 17 years. Public Staff references that in discovery that DE Carolina stated that the manufacturers of the meters estimate a life of 15 to 20 years and Ms. McCullar recommends an estimate in the middle of this range.

Q. DO YOU AGREE WITH PUBLIC STAFF'S ESTIMATE?

A. No. Ms. McCullar has not provided any new information in the instant case that supports changing the Commission-approved 15-year life. Indeed, Ms. McCullar's arguments are substantially similar to those she presented in the

[23] Sub 1146 Order at p. 117.

previous case that were not adopted by the Commission. Manufacturers' estimates are typically based only on the possible physical life of the assets. However, other factors can cause meters to retire. For example, meters can retire due to obsolescence. The 15-year life continues to be most appropriate for AMI meters.

V. LIFE SPANS OF CLIFFSIDE UNIT 5 AND ALLEN

Q. WHAT HAS THE COMPANY PROPOSED FOR CLIFFSIDE UNIT 5 AND THE ALLEN POWER STATION?

A. The Company plans to retire Units 4 and 5 at Allen in 2024 and Unit 5 at Cliffside in 2026. For both facilities, these are earlier dates than was anticipated in the previous depreciation study. I have incorporated these plans into the depreciation study and have recommended depreciation rates using these retirement dates.

Q. IS THERE A REQUIREMENT THAT ASSETS BE DEPRECIATED OVER THEIR SERVICE LIVES, RATHER THAN OVER A LONGER PERIOD OF TIME?

A. Yes. General Instruction 22A of the electric USOA states that:

> Utilities must use a method of depreciation that allocates in a systematic and rational manner the service value of depreciable property over the service life of the property.

Thus, the USOA requires that depreciation recover the costs of an asset (including net salvage) over its service life. Failing to recover costs over an asset's life will result in intergenerational inequity because it will result in costs for the asset to be recovered after the asset is retired. The result would be that future customers, who will not receive service from the retired asset, will have to pay the costs for an asset that is already retired.

Q. WHAT DOES STAFF PROPOSE?

A. Staff proposes to recover these costs of Allen and Cliffside Unit 5 over a longer period of time than the service lives of these plants. Staff's testimony on this issue is not entirely clear regarding the specifics of their proposal, although it does appear that Staff calculated new depreciation rates using the retirement dates from the prior study. Staff witness Boswell claims that she has "recommended that Public Staff witness McCullar restore the depreciation rate of these units to the depreciation rate approved in the Company's last general rate case in Docket No. E-7, Sub 1146."[24] However, Ms. McCullar states that she has "used the current approved final retirement year for Cliffside Unit 5 and Allen in the calculation of the Public Staff proposed depreciation rates,"[25] rather than using the current approved depreciation rates. Based on Ms. McCullar's exhibits, it appears that Staff proposes to use the currently approved retirement dates, with updated calculations of depreciation rates, rather than the current depreciation rates for these generating facilities.

[24] Boswell at 14:12-15.
[25] McCullar at 35:7-9.

Q. WILL STAFF'S PROPOSAL RESULT IN INTERGENERATIONAL EQUITY?

A. No. Public Staff's proposal will result in recovering a portion of the costs of these plants after they are retired, which will result in intergenerational inequity.

Q. WHAT JUSTIFICATION DOES STAFF PROVIDE FOR ITS PROPOSAL TO NOT RECOVER THE FULL COSTS OF THESE FACILITIES OVER THEIR SERVICE LIVES?

A. Public Staff witness Boswell provides two reasons for Public Staff's proposal. First, she claims that "although the Company has stated in its testimony that it intends to retire these plants, it has not presently done so."[26] This does not provide a justification to ignore Company plans and to fail to depreciate the costs of these facilities over their expected service lives. For the purposes of determining depreciation, one cannot wait until an asset is retired to determine its service life, because the costs need to be recovered over the asset's life (*i.e.*, before the asset is retired). As a matter of principle, the concept Ms. Boswell sets forth does not comport with the USOA or with generally accepted depreciation principles.

The second reason set forth by Ms. Boswell is that "the Public Staff has consistently recommended leaving the depreciation rates set at the original retirement date of the plant, and, at the date of actual physical retirement, any remaining net book value be placed in a regulatory asset account and amortized

[26] Boswell at 14:16-18.

over an appropriate period, to be determined in a future general rate case."[27] While Staff may have taken this position in the past, it is inequitable by definition. Any of the costs that would be placed in a regulatory asset account and amortized over a given period will be recovered after a facility is retired. Staff's proposal will, by design, result in intergenerational inequity.

I do recognize that there are some instances in which the date of retirement of a power plant is close to the date of a filed rate case (and that there can even be instances in which a plant is retired before a depreciation study is performed), which may necessitate the use of a regulatory asset. However, the expected retirement dates of Cliffside Unit 5 and Allen are four years or more from the test year in the depreciation study. As a result, there is still time to recover the costs of these plants over their service lives and the use of a longer period, as proposed by Staff, is unnecessary and will result in intergenerational inequity.

VI. ASH POND COSTS

Q. HAVE YOU REVIEWED THE JOINT TESTIMONY OF PUBLIC STAFF WITNESSES MANESS AND LUCAS ("JOINT TESTIMONY") REGARDING DEPRECIATION AND DECOMMISSIONING OF COAL PLANTS?

A. Yes.

[27] Boswell at 14:18-23.

Q HAVE YOU ALSO REVIEWED THE COMMISSION'S ORDER IN DOCKET NO. E-22, SUB 562, ISSUED ON FEBRUARY 24, 2020, AS IT RELATES TO ASH POND COSTS AND THE DECOMMISSIONING OF COAL PLANTS?

A. Yes. I am also aware that the Commission cited to my testimony in a case in South Dakota for Black Hills Power Company, which discussed the inclusion of terminal net salvage in depreciation.

Q. TO PROVIDE CONTEXT FOR THE RECOVERY OF DE CAROLINA'S COSTS AND YOUR TESTIMONY IN THE BLACK HILLS POWER CASE, PLEASE DISCUSS HOW DECOMMISSIONING COSTS HAVE BEEN ADDRESSED BY UTILITIES.

A. In the context of DE Carolinas' filing and the Commission's Order in Docket No. E-22, Sub 562, I think it is important to understand the background of the recovery of terminal net salvage costs in general – and coal ash costs in particular – throughout the utility industry. In discussing this history, it is important to recognize that there have been two distinct, though related issues with this concept. The first is the conceptual issue as to whether net salvage, and especially terminal net salvage, should be included in depreciation rates at all. The second is the issue of how to estimate these future costs. It is important to recognize that, historically, utilities have faced resistance – at times strong resistance – to both of these issues. Thus, not only has there been the challenge of estimating future net salvage costs, including the uncertainty what would be included for these future costs, but there has also been resistance to the basic concept of recovering terminal net salvage through depreciation.

I also want to make clear that throughout my career I have supported the idea that terminal net salvage should be included in depreciation rates. As I discuss in more detail below, this has been true for many years in previous studies for DE Carolinas. I have tried to consistently apply these concepts, both for DE Carolinas and other utilities both with respect to the potential retirements of coal plant facilities and generally. However, what has changed in the recent past is the degree of precision of estimating terminal net salvage for coal-fired generation facilities, which has improved as more information has become available and as the types of required decommissioning activities have become more certain.

Q. PLEASE EXPLAIN IN MORE DETAIL THE BACKGROUND OF THE RECOVERY OF TERMINAL NET SALVAGE COSTS IN THE INDUSTRY.

A. Throughout my career, the inclusion and estimation of terminal net salvage has been one of the more contentious issues in rate cases (as has the somewhat related issue of estimating the life spans of power plants). It is only relatively recently that a wider consensus has emerged on required decommissioning activities. Prior to recent years, many intervenors, commission staffs and commission orders had argued that terminal net salvage costs were not likely to be incurred. The arguments why this would be the case and the proposals varied, but generally many argued that companies' coal-fired power plants were likely to operate indefinitely, that decommissioning costs were unlikely because the site could be reused, that decommissioning costs were too speculative, or that these costs should simply be recovered once they were incurred. Even to the extent that decommissioning costs were included in depreciation studies, the costs were often challenged and reduced.

Indeed, this was the context of the testimony I provided in South Dakota that the Commission cited in its recent order. A consultant hired by an industrial intervenor group in that case had proposed that terminal net salvage be excluded from depreciation altogether. To be clear, this consultant's proposal was not just to exclude ash pond costs, but to exclude all terminal net salvage costs. As a result, my rebuttal testimony not only had to support the estimated terminal net salvage, but also had to explain why terminal net salvage should be included in depreciation at all.

Unfortunately, the view of the consultant in that case has been more pervasive than I would hope. While a stronger consensus has emerged for the inclusion of terminal net salvage in depreciation, it is unfortunately not universally agreed upon. Indeed, Public Staff's consultant in the instant case not only indicates a preference to reduce terminal net salvage below the expected future costs, but to support her position she cites to two commissions (Missouri and West Virginia) that have not included terminal net salvage in depreciation at all. This appears to be a continuation of the argument that has been espoused by some that terminal net salvage costs may not be incurred and therefore should be excluded from depreciation. I have also attended a presentation made by Staff's consultant in which she argued that removal costs for power plants (i.e., terminal net salvage) may not be incurred, which was at a minimum an implicit argument against recovering terminal net salvage in depreciation. I also note that in the instant case, as discussed in Section V of my rebuttal, Public Staff has not espoused the matching principle the Commission discusses in the order in Docket No. E-22, Sub 562. By proposing to depreciate Allen and Cliffside Unit 5 over a period longer than they will be in service, Public Staff's proposal will fail to match the costs of these plants with revenues and defer recovery to future ratepayers.

I believe that it is against this overall context that the Commission should judge past recoveries of coal ash costs. One must keep in mind that, at least with regard to coal-fired power plants, it is a very different world today than it was in the first decade of the 2000s. Over the last ten years or so, the combination of cheap natural gas and environmental regulations has resulted in significant retirements of coal-fired generation across the industry. However, in the earlier period, gas was more expensive, there were fewer regulations on coal-fired generation, and the newer technologies that have replaced them were less developed. The outlook for these types of assets was very different than it is today. With the benefit of hindsight, many of the arguments made in the earlier period for long life spans for coal plants and excluding decommissioning costs have proven to be incorrect. However, in the context of that period they were more convincing to many people. Again, at the time I argued for shorter life spans and the inclusion of decommissioning, but in the context of the times these were more difficult arguments to make and they were not readily accepted.

Q. PRIOR TO DOCKET NO. E-7, SUB 1146, WERE NET SALVAGE COSTS INCLUDED IN THE DEPRECIATION RATES FOR DE CAROLINAS?

A. Yes. In the depreciation studies I performed as of 2003, 2007 and 2011, net salvage was estimated for most production plant accounts. That is, the depreciation studies for DE Carolinas have consistently included net salvage and the estimates for production facilities have included terminal net salvage. The issue is not that the Company has not included net salvage in its depreciation rates, but rather that the information we have today shows that the costs will be higher than anticipated. In addition to the background discussed above, this is a function of the challenge in estimating future costs, which the Commission has recognized in noting that even though DE Progress included coal ash costs in its decommissioning studies, these estimates were too low compared to actual costs.[28]

Q. DID THE NET SALVAGE ESTIMATES IN PRIOR DE CAROLINAS STUDIES INCLUDE TERMINAL NET SALVAGE?

A. Yes. However, the terminal net salvage costs were not based on a decommissioning study as has been the case in the last two depreciation studies (i.e., Docket No. E-7, Sub 1146 and the instant case). Due to factors such as the uncertainty of decommissioning costs, the tasks involved in decommissioning, and the timing of these costs the Company did not have similar decommissioning studies performed for the 2011 depreciation study and earlier studies. Instead, the estimates in those studies were based on the analysis of historical net salvage and

[28] Order in Docket No. No. E-22, SUB 562 at 141.

retirements for production plant accounts. Because these estimates were implied to the entire account (rather than just the portion to be retired as interim retirements), they implicitly included a terminal net salvage component. Thus, although the specific cost elements were not defined, DE Carolinas has been recovering terminal net salvage costs since at least 2003. In Docket No. E-7, Sub 1146, the specific decommissioning costs were more certain and, therefore, could be included at a greater level of detail.

Q. ON PAGE 142 OF THE COMMISSION'S ORDER IN DOCKET NO. E-22, SUB 562, THE COMMISSION NOTED THAT IN YOUR TESTIMONY FOR BLACK HILLS POWER YOU OBSERVED THAT DUKE ENERGY PLANNED TO DECOMMISSION A NUMBER OF SITES IN THE CAROLINAS, INCLUDING THE CLOSURE OF ASH PONDS. WAS THE TESTIMONY FOR BLACK HILLS PRIOR TO DE CAROLINA'S 2011 DEPRECIATION STUDY?

A. No. My testimony in the Black Hills Power case was filed in 2015. At that point, it was known that DE Carolinas would decommission a number of facilities. This differs from the 2011 depreciation study for DE Carolinas. At the point I prepared that study there was more uncertainty about future net salvage costs.

Q. THE JOINT TESTIMONY OF PUBLIC STAFF REFERS TO A DATA REQUEST (DR NO. 158) SERVED UPON THE COMPANY BY THE PUBLIC STAFF, RESPONSES TO WHICH ARE SET OUT IN LUCAS AND MANESS EXHIBIT 1. DID YOU PARTICIPATE IN PROVIDING THE RESPONSES TO THIS DATA REQUEST?

A. Yes, and in particular with respect to subparts 1-4 of DR 158.

Q. ON PAGE 11 OF THE JOINT TESTIMONY, AT LINES 12-13, WITNESSES LUCAS AND MANESS RECOMMEND THAT THE COMPANY ADDRESS AN ISSUE DISCUSSED IN THEIR TESTIMONY, NAMELY WHETHER ANY "PORTION OF THE PREVIOUSLY UTILIZED SALVAGE PERCENTAGES ARE ALLOCABLE TO IMPOUNDMENT RETIREMENT OR CLOSURE COSTS." PLEASE COMMENT.

A. As to "retirement or closure costs," I assume that the Joint Testimony is referring to decommissioning costs associated with the closure of coal ash basins, such as excavating the ash and/or capping it in place, dealing with environmental issues, *et cetera*. Alluding to the depreciation studies submitted in connection with three DE Carolinas rate cases prior to 2017 (Docket Nos. E-7, Sub 783; E-7, Sub 909; and E-7, Sub 1026), the response to DR 158-1 states clearly and unequivocally that *none* of the "net salvage percentages include or account for anticipated costs of coal ash removal or remediation, or retirement/decommissioning of coal ash impoundments or storage facilities." The referenced depreciation studies, which were dated as of December 31, 2003 (E-7, Sub 783), December 31, 2008 (E-7, Sub

909), and December 31, 2011 (E-7, Sub 1026) were all prepared under my direction.

Q. DO THE RESPONSES TO DR 158 DETAIL WHY THIS IS THE CASE?

A. Yes. The Joint Testimony quotes in part from the response to DR 158-3 at page 10, lines 3-12. The response in full, which is included in Lucas and Maness Exhibit 1, is as follows:

> Prior to approximately the mid-2010s, and particularly in connection with the promulgation of the US Environmental Protection Agency's final rule on coal combustion residuals ("CCR Rule"), it was not standard industry practice to include anticipated costs of coal ash impoundment closure in net salvage portion of depreciation expense for several reasons. In the early part of the period specified in DR 1 above, it was not common to have decommissioning studies performed that included coal burning facilities because the prevailing presumption by electric companies at that time was that such facilities would continue to provide power in same function [sic, should read "some fashion"] well into the future. Moreover, ash basins would continue serving their function of holding CCRs and would in that connection continue to be managed and permitted. Without a definite plan to decommission these plants, or the specific manner at which the facility will be decommissioned, it was not appropriate to include decommissioning costs related to coal ash basin closures in the calculation of depreciation rates. Further, as a general matter, pre-CCR Rule coal ash basin closures ordinarily were planned and carried out in conjunction with the relevant environmental authorities. While DEC began assessing the requirements for and anticipated costs of coal ash basin closure in the years immediately prior to the promulgation of the CCR Rule and enactment of North Carolina's Coal Ash Management Act (CAMA), as evidenced, for example, by AGO Fountain Direct Cross Ex. 6 and AGO Late Filed Ex. 1(L) in Docket E-7, Sub 1146, there was no clarity from federal or North Carolina environmental authorities as to how closure would be accomplished, rendering any cost estimations

> speculative. Further, following the enactment of CAMA and promulgation of the CCR Rule, which were the triggering events for the establishment of coal ash basin closure AROs, the applicable accounting rules shifted to ARO accounting rather than recovery of net salvage costs through depreciation expense. See also response to DR 158-1.

Company witness Doss discusses in his testimony the accounting rules in connection with the establishment and treatment of AROs.

Q. IN ITS PARTIAL QUOTATION OF THIS RESPONSE, THE JOINT TESTIMONY INSERTS "EARLY 2000S" IN AN ATTEMPT TO FURTHER DATE THE "EARLY PART OF THE PERIOD" COVERED BY THE RESPONSE. IS THIS AN ACCURATE REPRESENTATION?

A. It is an incomplete representation, at least with respect to the Company. The reference to the "early part of the period" must be read in the context, which refers to "coal burning facilities" – i.e., coal-fired power plants as a whole, not just coal ash basins. In the case of the Company, it was not until the early 2010s that closure and retirement of coal-fired plants became a reality, due to the combination of tighter environmental regulation coupled with the falling price of natural gas. In summary, with tighter environmental regulation requiring plant upgrades to existing plants, and the falling price of natural gas rendering the cost of those upgrades untenable in light of gas-powered alternative supply, the Company along with many other utilities opted to shut down and retire some coal-fired plants rather than retrofit them. Accordingly, a more complete representation of the response would be that for the Company the initial period referred to extends through the first decade of the 2000s.

Q. DID YOU HAVE DISCUSSIONS WITH THE COMPANY REGARDING WHETHER COAL ASH BASIN CLOSURE COSTS SHOULD BE INCLUDED IN NET SALVAGE AND, AS A CONSEQUENCE, IN DEPRECIATION EXPENSE?

A. Yes. This is alluded to in response to DR 158-4. Specifically, this was a topic of discussion in the Fall of 2011, in connection with my preparation of the depreciation study dated December 31, 2011, which was ultimately used in Docket No. E-7, Sub 1026.[29] The discussion included, as the Joint Testimony indicates (*see* page 10, lines 16-17), a PowerPoint presentation of a high level decommissioning evaluation. That PowerPoint presentation was produced in response to DR 158-4 and is included in Lucas and Maness Exhibit 1.

Q. WHAT WAS THE RESULT OF THESE DISCUSSIONS?

A. The PowerPoint presentation indicates an estimate of ash basin closure costs in an amount in excess of $1 Billion, related to all of the Company's ash basins. As Slide 7 indicates, these cost estimates were based upon the assumption that coal ash would not be classified as a hazardous waste when the CCR Rule (which was then in only a proposed state) was finalized, and that the closure method would be

[29] At that time, it was anticipated that the Company would file a rate case in 2012. Ultimately this did not happen. It is my understanding that the filing was delayed by the July 2, 2012 merger of Duke Energy Corporation and Progress Energy, Inc. Shortly after the merger, the operating utility now known as Duke Energy Progress, LLC ("DE Progress," then known as Progress Energy Carolinas, Inc.) filed a rate case (Docket No. E-2, Sub 1023), and the DE Carolinas rate case was filed in early 2013.

to cap the ash in place with a synthetic cap. The consensus we came to at the time was that these estimates were too speculative and would not support rigorous scrutiny from the Public Staff and/or the Commission. In addition, as Slide 7 also notes, there was an expectation that the CCR Rule would be finalized some time in 2012 (at least, "at the earliest"). Assuming the final Rule included a legal requirement to close coal ash basins, the Company advised that this new requirement would trigger the establishment of an Asset Retirement Obligation ("ARO") related to such closure.

Q. YOU REFER IN YOUR ANSWER TO A PREVIOUS QUESTION TO THE 2012 RATE CASE FILED BY DE PROGRESS. ARE YOU AWARE THAT IN THAT CASE DE PROGRESS DID INCLUDE ASH BASIN CLOSURE COSTS IN NET SALVAGE?

A. Yes. I am aware that Burns & McDonnell prepared two decommissioning studies, dated as of January 2012, for DE Progress (then Progress Energy Carolinas, a subsidiary of Progress Energy, Inc.) – one with respect to "near term" units to be decommissioned, and the other with respect to "future" units to be decommissioned. These studies did present decommissioning cost estimates for coal-fired power plants, including their associated coal ash basins. I am also aware that these studies were then utilized in connection with the calculation of net salvage value in a depreciation study, and in the calculation of depreciation expense to be included in cost of service.

Q. WAS DE PROGRESS WRONG TO TAKE THIS APPROACH?

A. No. While this was not as common of an approach at the time, DE Progress was not wrong to take it, particularly as it was based upon estimates of decommissioning cost prepared by an independent third party. The Public Staff and the Commission both accepted this approach in Docket No. E-2, Sub 1023, and they also accepted the approach followed by DE Carolinas in Docket No. E-7, Sub 1026. Neither approach is "wrong"; rather, they were at the time both different but acceptable methods of calculating depreciation expense based on the information available and each company's judgment regarding the uncertainty of coal ash costs. The approach taken by DE Carolinas was simply more conservative than that of DE Progress.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Duke Energy Carolinas, LLC
Summary of Rebuttal Testimony of John Spanos
Docket No. E-7, Sub 1214

My rebuttal testimony addresses two primary topics. The first is a response to criticisms or proposed changes to my depreciation study performed for DEC in this proceeding. The second is to address certain net salvage related testimony of Public Staff witness Maness concerning CCR impoundment facility closure costs.

On the first topic, my rebuttal testimony rejects several proposals by Public Staff witness McCullar to modify my net salvage calculations and addresses the proper service life for AMI meters. In general, each of my net salvage calculations and the use of a 15-year service life for AMI meter depreciation are consistent with accepted depreciation practices and the prior decisions of this Commission. The only exception to the prior Commission decision is my use of a 20% contingency factor for calculating net salvage based on the decommissioning study, which is higher than the currently approved percentage, but which is justified based on recent experience in the industry.

On the second topic, I begin my discussion of the issue of including terminal net salvage costs in depreciation studies by noting that including such costs in depreciation expense for state regulatory ratemaking purposes has been controversial and there is little consensus as to how to calculate terminal net salvage costs for coal ash impoundment facilities. While I have been a consistent advocate for including terminal net salvage in depreciation expense in the studies I have performed, it is only very recently that a prevailing consensus has emerged supporting this approach on an industry-wide basis.

DEC has included some net salvage costs for all plant in service in its depreciation studies since at least 2003, even though prior to 2011 the specific cost elements were not defined as those depreciation studies were not based upon decommissioning studies. Further, none of DEC's depreciation studies prior to 2017 included specific costs of coal ash impoundment facility closure or remediation. This was the case because DEC did not consider it appropriate as a matter of depreciation standards to include those costs in DEC's depreciation rates without definitive closure plans for such facilities.

At the time CAMA was enacted and the federal CCR Rule was promulgated, DEC determined to establish AROs to address requirements associated with the retirement and remediation of coal ash impoundment facilities. That decision, along with the establishment of the corresponding AROs, removed CCR impoundment closure costs from consideration in calculating DEC's depreciation rates. Based on my experience, this sequence of events was not in any way abnormal within the electric industry in the United States or otherwise out of the range of reasonable responses to the initial uncertainty and then growing clarity that developed around liabilities associated with the closure of coal ash impoundment facilities during the period 2000 through 2015 and thereafter.

This concludes the summary of my rebuttal testimony.

MR. JEFFRIES: And just as a point of clarification, Chair Mitchell, I believe that Mr. Spanos' direct testimony and exhibits were identified in the consolidated portion of this hearing and were moved into evidence at the beginning of the DEC-specific, but that's my belief anyway. And with that, I will turn this over to Mr. Marzo to introduce Mr. Doss.

CHAIR MITCHELL: All right. Mr. Marzo.

MR. MARZO: Thank you, Chair Mitchell.

DIRECT EXAMINATION BY MR. MARZO:

Q. Mr. Doss, would you please state your name and business address for the record?

A. (David L. Doss, Jr.) My name is David Doss, and my business address is 550 South Tryon Street, Charlotte, North Carolina 28202.

Q. And by whom are you employed and in what capacity?

A. I'm employed by Duke Energy Business Services as the director of asset accounting.

Q. Thank you, Mr. Doss. Mr. Doss, did you cause to be prefiled in this docket, rebuttal testimony consisting of 25 pages?

A. Yes.

Q. Do you have any changes or corrections to your prefiled rebuttal testimony?
A. No, I don't.
Q. If I were to ask you the same questions today, would your answers be the same?
A. Yes, they would.
Q. Did you also cause to be prefiled, Doss Rebuttal Exhibit 1 to your rebuttal testimony?
A. Yes.
Q. Do you have any changes or corrections to your prefiled rebuttal exhibit?
A. No.
MR. MARZO: Chair Mitchell, at this time I would ask that Mr. Doss' prefiled rebuttal testimony be entered into the record as if given orally from the stand, and that Doss Rebuttal Exhibit 1 to his rebuttal testimony be marked for identification.
CHAIR MITCHELL: All right. Mr. Doss' rebuttal testimony would be copied into the record as if given orally from the stand, and the exhibit to that testimony will be marked as it was when prefiled.
MR. MARZO: Thank you, Chair Mitchell.

(Doss Rebuttal Exhibit 1 was identified as it was marked when prefiled.)

(Whereupon, the prefiled rebuttal testimony of David L. Doss, Jr. was copied into the record as if given orally from the stand.)

I. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David L. Doss Jr., and my business address is 550 South Tryon Street, Charlotte, North Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Business Services, LLC, a service company affiliate of Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company"), as Director of Asset Accounting. DE Carolinas is a subsidiary of Duke Energy Corporation (together with its subsidiaries "Duke Energy").

Q. DID YOU OFFER ANY DIRECT TESTIMONY IN THIS PROCEEDING?

A. No.

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony will address certain comments and recommendations submitted by Public Staff witness Michael C. Maness with respect to the Company's Asset Retirement Obligation ("ARO") accounting for coal ash basin closure cost. In addition, I will address Public Staff witness Dustin R. Metz's recommendation to disallow Belews Creek Dual Fuel Operation ("DFO") projects based on his conclusion that the project is not commercially operational. Specifically, I will explain the accounting that the Company followed in determining when to place the Belews Creek DFO project in service.

III. ARO ACCOUNTING FOR COAL ASH BASIN CLOSURE COSTS

Q. DO YOU AGREE WITH PUBLIC STAFF WITNESS MANESS' CONCLUSION THAT THE DEFERRED COAL ASH BASIN CLOSURE COSTS PROPOSED BY DE CAROLINAS IN THIS CASE FALL INTO THE CATEGORY OF A DEFERRED EXPENSE?

A. I do not. I believe Mr. Maness incorrectly characterizes the facts upon which the Company's ARO accounting is based. On page 30 of his testimony, Mr. Maness, as he did in Docket No E-7, Sub 1146 asserts once again that "The Company has itself chosen to request a regulatory accounting and ratemaking method that does not explicitly account for any coal ash compliance costs, either in the past or in the future, as the capitalized costs of property, but instead accounts for them as ongoing expenses, with a proposed regulatory asset intended to provide for the recovery of expenses incurred in the past, expenses that but for the Commission's approval of the deferral request, would be immediately written off." This is simply incorrect. Rather than "choosing" a particular path, the Company was required to (and did) adhere to and apply the accounting guidance under GAAP and Federal Energy Regulatory Commission ("FERC") Code of Federal Regulations ("CFR"), as well as Orders of this Commission.

Q. **PLEASE EXPLAIN WHAT TRIGGERED THE GAAP AND FERC GUIDANCE THAT THE COMPANY IS REQUIRED TO FOLLOW WITH RESPECT TO ITS COAL ASH BASINS.**

A. The Company evaluated GAAP and FERC guidance in light of the legal obligations imposed upon it by North Carolina's Coal Ash Management Act ("CAMA"), which was originally enacted in 2014, and the Environmental Protection Agency's ("EPA") Coal Combustion Residuals Rule ("CCR Rule"), which was promulgated in 2015. The Company determined that the coal ash basins it operated at its coal-fired generating facilities needed to be closed as a result of the passage of CAMA and/or the CCR Rule. The closure obligation triggered ARO accounting requirements.

Q. WHAT GAAP REQUIREMENTS MUST DE CAROLINAS FOLLOW IN CONNECTION WITH COAL ASH BASIN CLOSURE?

A. Statement of Financial Accounting Standard ("SFAS") No. 143 (now codified as ASC 410) was effective for and implemented by the Company in 2003 for financial reporting purposes. This guidance requires recognition of liabilities for the expected cost of retiring tangible long-lived assets for which a legal retirement obligation exists. GAAP (in ASC 410-20-20) refers to these costs as an "Asset Retirement Obligation" or an ARO, and defines a "legal obligation" as an "obligation that a party is required to settle as a result of an existing *or enacted* law …." (Emphasis added). Each of CAMA and the CCR Rule qualify as an "enacted law" under this guidance.

A copy of the relevant GAAP guidance is attached to my testimony as Doss Rebuttal Exhibit 1. Based on the guidance in my Rebuttal Exhibit 1, DE Carolinas evaluated the retirement requirements of CAMA and the CCR Rule and concluded that DE Carolinas should record an ARO for the closure of its coal ash basins. The key concepts and their related GAAP provisions are as follows.

First, it is important to understand the scope of the ARO guidance. This is the subject of ASC 410-20-15. Subtopic 15-2 indicates that the guidance applies to the following transactions and activities:

a) Legal obligations associated with the retirement of a tangible long-lived asset that result from the acquisition, construction, or development and (or) the normal operation of a long-lived asset, including any legal obligations that require disposal of a replaced part that is a component of a tangible long-lived asset.

b) An environmental remediation liability that results from the normal operation of a long-lived asset and that is associated with the retirement of that asset. The fact that partial settlement of an obligation is required or performed before full retirement of an asset does not remove that obligation from the scope of this Subtopic. If environmental contamination is incurred in the normal operation of a long-lived asset and is associated with the retirement of that asset, then this Subtopic will apply (and Subtopic 410-30 will not apply) if the entity is legally obligated to treat the contamination.

c) A conditional obligation to perform a retirement activity. Uncertainty about the timing of settlement of the asset retirement obligation does not remove that obligation from the scope of this Subtopic but will affect the measurement of a liability for that obligation (see paragraph 410-20-25-10).

Here, the coal ash basins being retired are tangible long-lived assets, and so Subtopic 15-2(a) applies. In addition, to the extent that retirement involves any environmental remediation, that remediation is the result of the normal operation of the basins, which is the subject of Subtopic 15-2(b). As noted in Company witness Kerin's testimony in Docket No. E-7, Sub 1146 and witness Bednarcik in this case, the use of ash impoundments as a storage location for coal ash and other CCR was in accordance with industry standards and then-applicable regulations. Finally, under Subtopic 15-2(c), the retirement requirements are a conditional obligation to perform a retirement activity as the nature, timing and extent of the closure depends on various determinations. In CAMA, those determinations revolve around the legislative or the North Carolina Department of Environmental Quality assessed risk rankings. Under the CCR rule, those determinations revolve around the evaluation of certain criteria by specific deadlines.

Second, it is important to distinguish the activities captured in the coal ash basin closure ARO with other environmental remediation activities. Subtopic 15-3 indicates that certain transactions and activities are not permitted to be included in the ARO. Specifically, as set out in Subtopic 15-3(b):

b) An environmental remediation liability that results from the improper operation of a long-lived asset (see Subtopic 410-30). Obligations resulting from improper operations do not represent costs that are an integral part of the tangible long-lived asset and therefore should not be accounted for as part of the cost basis of the asset. For example, a certain amount of spillage may be inherent in the normal operations of a fuel storage facility, but a catastrophic accident caused by noncompliance with an entity's safety procedures is not. The obligation to clean up the spillage resulting from the normal operation of the fuel storage facility is within the scope of this Subtopic. The obligation to clean up after the catastrophic accident results from the improper use of the facility and is not within the scope of this Subtopic.

Costs associated with the Company’s Dan River spill, for example, are covered by Subtopic 15-3(b), and, therefore, are not included in the coal ash basin closure ARO. DE Carolinas concluded that based on the guidance noted above that the retirement requirements relating to the closure of the ash impoundments under CAMA and the CCR Rule were Asset Retirement

Obligations. Therefore, the accounting for costs as it relates to the retirement of the coal ash impoundments must follow ARO accounting under GAAP.

Q. DOES DE CAROLINAS HAVE INTERNAL CONTROLS TO DETERMINE WHAT TYPES OF COSTS ARE CONSIDERED ARO?

A. Yes. DE Carolinas has internal controls to ensure transactions related to these costs are properly evaluated for accounting treatment. As I explained in Docket No E-7, Sub 1146, DE Carolinas has implemented a Coal Ash ARO Charging Committee whose purpose is to evaluate costs to be incurred for determination as to whether they qualify for ARO accounting treatment. The Committee utilizes the guidance in ASC 410, other GAAP, FERC and Commission guidance and Duke Energy Corporation accounting policies to make these determinations. Specifically, for example, the Committee utilizes ASC 410-20-55-13 to determine the extent of costs to include in the ARO. Decisions of the Coal Ash ARO Charging Committee are summarized in a charging guidelines document.

Q. ARE THE DECISIONS OF THE COMMITTEE REVIEWED?

A. Yes. The Committee's decisions are reported back to the Coal Combustion Products ("CCP") group to ensure that 1) all relevant facts were appropriately communicated by CCP and understood by the Committee, and 2) that the CCP group understands the decisions to properly categorize actual project costs.

Q. ARE THERE AUDITS PERFORMED ON THE ACCOUNTING AND FINANCIAL REPORTING IN CONNECTION WITH THE COAL ASH ARO?

A. Yes. The Company's auditors, Deloitte & Touche LLP, perform the annual audit of the Company's financial statements. Deloitte & Touche has issued its opinion that the financial statements are presented fairly, in all material respects, in conformity with U.S. GAAP standards. Deloitte & Touche also performs a review of the FERC Form 1 and issues its opinion that the regulatory basis financial statements are presented fairly, in all material respects, in conformity with the FERC Uniform System of Accounts. Finally, Deloitte & Touche also issues an opinion on internal controls that states that Duke Energy Corporation maintained, in all material respects, effective internal control over financial reporting.

Q. IN ADDITION TO THE ACCOUNTING REQUIREMENTS UNDER GAAP, ARE THERE FERC ACCOUNTING REQUIREMENTS THAT DE CAROLINAS MUST FOLLOW?

A. Yes. In addition to being required to follow GAAP, DE Carolinas is regulated by FERC which requires the use of the FERC Uniform System of Accounts, which states:

> (A) An asset retirement obligation represents a liability for the legal obligation associated with the retirement of a tangible long-lived asset that a company is required to settle as a result of an existing or enacted law,

> statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel. An asset retirement cost represents the amount capitalized when the liability is recognized for the long-lived asset that gives rise to the legal obligation. The amount recognized for the liability and an associated asset retirement cost shall be stated at the fair value of the asset retirement obligation in the period in which the obligation is incurred.

The FERC Uniform System of Accounts General Instruction No. 25 also requires that "a utility initially record a liability for an ARO in Account 230 — Asset Retirement Obligations, and charge the associated asset retirement costs to the electric utility plant that gave rise to the legal obligation in Account 101- Electric Plant in Service. The asset retirement cost is to be depreciated over the useful life of the related asset that gives rise to the obligation by recording a debit to Account 403.1- Depreciation Expense for Asset Retirement Costs and a credit to Account 108 Accumulated Provision for Depreciation of Electric Utility Plant. In periods subsequent to the initial recording of the ARO, the utility shall recognize the period-to-period changes of the ARO that result from the passage of time due to the accretion of the liability by recording a debit to Account 411.10 — Accretion Expense, and a credit to Account 230."

Q. IN ADDITION TO THE ACCOUNTING REQUIRED BY GAAP AND FERC AS STATED ABOVE, WHAT ARE THE REQUIREMENTS ISSUED BY THE COMMISSION?

A. While both GAAP and the FERC Uniform System of Accounts require the recognition in the income statement of depreciation expense and accretion expense, the Commission has required these amounts to be deferred into regulatory assets. In 2003, after the ARO accounting guidance was required to be implemented by the Financial Accounting Standards Board, the Commission ruled in Docket No. E-7, Sub 723 "That the implementation of SFAS 143 for financial reporting purposes and the deferrals allowed in this docket shall have no impact on the ultimate amount of costs recovered from the North Carolina retail ratepayers for nuclear decommissioning or other AROs, subject to future orders of the Commission." Those deferrals allowed in the docket related to the depreciation and accretion expenses required by GAAP and FERC noted in my testimony.

The Company's deferral request of costs incurred and the recovery request in this rate case are in accordance with the deferral Order the Commission issued in Docket No. E-7, Sub 723.

Q. HAVE YOU PROVIDED TESTIMONY PREVIOUSLY ON THE GAAP, FERC, AND DEFERRAL DIRECTIVES THAT GOVERN THE MANNER IN WHICH THE COMPANY ESTABLISHED THE ARO FOR COAL ASH BASINS?

A. Yes, I provided testimony in Docket E-7, Sub 1146 fully explaining the GAAP, FERC and deferral requirements that governed DE Carolinas' establishment of the ARO for the coal ash basin closure costs. In the Commission's Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction in that case the Commission expressly credited my explanation and testimony regarding GAAP, FERC and deferral directives and found my testimony to be un-contradicted in that case. (E-7, Sub 1146 Rate Order, p. 148.)

Q. DO YOU AGREE WITH WITNESS MANESS' ASSERTION THAT "THE COMPANY HAS USED AN ACCOUNTING AND RATEMAKING MODEL THAT ACCOUNTS FOR AND RECOVERS THE ARO-RELATED COAL ASH CLEANUP COSTS AS EXPENSES ON AN "AS-SPENT" OR "AS-ACCRUED" BASIS?

A. No. I believe that Mr. Maness has mischaracterized the accounting treatment the Company is applying to the coal ash related costs. The cash outflows to which he refers are not recorded as an expense on the books of DE Carolinas. In accordance with GAAP and FERC rules, these costs were accrued previously as a capital cost in electric utility plant as part of the Asset

Retirement Cost (ARC) related to the ARO, and the Company has already recognized depreciation expense through the life of the ARC and accretion expense over the period of expected settlement of the ARO. *See* ASC 410-20-25-5. However, in the case of DE Carolinas and pursuant to the Commission's Orders in Docket No. E-7, Sub 723, the depreciation and accretion expenses were deferred. The amount spent related to the coal ash basin closure ARO is effectively the portion of the depreciation and accretion expenses that were previously deferred in accordance with Commission orders and which has now been incurred as the Company has expended cash to settle its ARO. Although for ratemaking purposes the Company is seeking recovery of these cash costs on an "as-spent" or "as-incurred" basis, Mr. Maness' claim that the Company has used an accounting model that accounts for these cash outflows as expenses is incorrect. In the Company's financial statements, these cash outflows are reflected as a reduction to cash and a reduction to the ARO; an ARO which, when it was established, was charged as an ARC to the electric utility plant that gave rise to the legal obligation, in accordance with GAAP and FERC rules.

Q. DO YOU AGREE WITH WITNESS MANESS' ASSERTION THAT THE COMPANY IS NOT UTILIZING ARO ACCOUNTING AS PRESCRIBED BY FASB?

A. No, I do not. Mr. Maness seems to imply that the Company's accounting related to its coal ash AROs is not in compliance with Generally Accepted

Accounting Principles ("GAAP") as promulgated by FASB. This simply is not true. As explained earlier in my testimony, the Company has accounted for its coal ash AROs in accordance with the GAAP requirements that govern ARO accounting as found in ASC 410-20. In addition, as a regulated utility, DE Carolinas must comply with FASB ASC 980 "Regulated Operations" which requires cost-based, rate-regulated enterprises, such as DE Carolinas, to reflect the impacts of decisions of its regulators in their financial statements. Pursuant to this requirement and as noted earlier in my testimony, DE Carolinas has reflected in its financial statements the impacts of the Commission's directives regarding the deferral of coal ash ARO related costs.

Q. COULD THE COMPANY HAVE CHOSEN TO FOLLLOW THE GAAP METHODOLOGY FOR NONREGULATED COMPANIES AS SUGGESTED BY WITNESS MANESS?

A. No. Although it is not clear, Mr. Maness seems to suggest on page 30 of his testimony that the Company could have chosen not to apply the GAAP provisions of ASC 980, and instead accounted for its ARO-related coal ash compliance costs as if it were an enterprise that is not subject to regulation for rates and other matters by the Commission. However, DE Carolinas is subject to regulation by the Commission, and therefore it meets the definition of a rate-regulated enterprise under ASC 980 and must comply with the requirements of ASC 980; it is not a choice as Mr. Maness seems to suggest.

Q. **HAS THE COMPANY "CHOSEN" A TOTALLY DIFFERENT APPROACH THAN THE ONE TYPICALLY FOLLOWED FOR UTILITY PROPERTY AS WITNESS MANESS SUGGESTS?**

A. No. The Company has simply accounted for these costs as required under GAAP and the FERC Uniform System of Accounts. Further, as it was authorized to do by the Commission, the Company deferred the impacts of ARO accounting, and now seeks an order from the Commission with regards to recovery.

Q. **WHAT OTHER ARGUMENT DOES WITNESS MANESS MAKE TO SUPPORT HIS CLAIM THAT THE COAL ASH RELATED ARO COST SHOULD BE TREATED AS AN EXPENSE?**

A. Witness Maness also states that "the ARO related cost proposed for deferral and amortization themselves are not in any manner costs related to present or future operations; instead they are costs that but for Commission approval of the deferral and amortization will be immediately written off as expenses related to the past." Once again, Witness Maness ignores the fundamental nature of ARO accounting and the requirements adhered to by the Company to reach a conclusion that the Commission should classify these costs as "deferred expenses."

As I previously testified, the Company is required to account for Asset Retirement Obligations in accordance with GAAP and FERC guidance. Under both GAAP and FERC guidance the asset created when a Company initially recognizes an ARO is considered part of the property, plant and equipment for the assets which must be eventually retired.

GAAP states, in ASC 410-20-25-5, with regards to recognition of the asset related to the recognition of the ARO that:

> Upon initial recognition of a liability for an asset retirement obligation, an entity shall capitalize an asset retirement cost by increasing the carrying amount of the related long-lived asset by the same amount as the liability.

Similarly, the FERC guidance regarding Asset Retirement Costs in General Instruction Number 25 for asset retirement obligations states that: "The utility shall initially record a liability for an asset retirement obligation in account 230, Asset retirement obligations, and charge the associated asset retirement costs to electric utility plant and nonutility plant, as appropriate, related to the plant that gives rise to the legal obligation."

By characterizing coal ash ARO related costs as expenses, witness Maness ignores the fact that both the FASB and FERC have ruled that asset retirement costs are an integral part of the plant asset that gives rise to the ARO, and therefore must be capitalized as part of such asset. Although plant assets are eventually expensed over time through charges to depreciation expense, it does not change the fact that the FASB and FERC have ruled that ARO related costs are capital in nature and in origin.

Q. HAS THE COMMISSION PREVIOUSLY CONSIDERED THE ARGUMENT THAT THE COAL ASH ARO COST SHOULD BE CLASSIFIED AS DEFERRED EXPENSES?

A. Yes. In Docket No. E-7, Sub 1146, which was the Company's last rate case, Witness Maness made similar arguments for the classification of coal ash ARO related cost as "deferred expenses" ("2018 Rate Order").[1] In the 2018 Rate Order, the Commission acknowledged that DE Carolinas has accounted for these costs as required under GAAP and FERC Uniform System of Accounts. The Commission further found that, under GAAP, the costs (no matter what their classification), are capitalized pursuant to ASC 410-20-25-5. Under FERC accounting, they are capitalized as well. Accordingly, 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. Thus, as the Commission concluded in its Order in DE Carolinas' last rate case, "witness Maness' classification of these costs as "deferred expenses" is not persuasive, not supported by authority and not determinative, given the nature of deferral," and "[i]t is also incorrect as a matter of accounting." The Commission further concluded that "the nomenclature

[1] *See Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction*, Docket No E-7, Sub 1146 (June 22, 2018) ("2018 Rate Order").

relied upon in GAAP and FERC is costs, assets, and liabilities, not expenses."[2]

Q. WAS THE ACCOUNTING FOR THE COAL ASH BASIN CLOSURE COSTS FULLY UNDERSTOOD BY PUBLIC STAFF AND OTHER INTERESTED PARTIES?

A. Yes. As early as December 21, 2015, the Company, through its then Chief Accounting Officer, notified the Commission through a letter of the manner in which it was required to account for coal ash basin closure costs. The letter explained GAAP and FERC accounting requirements regarding AROs. The letter described the triggering events for creation of the ARO, noting the promulgation of the CCR Rule and the passage of CAMA; it indicated that an ARO related to the closure of coal ash basins was recorded on the Company's balance sheet; it indicates further that a corresponding asset was recorded "as part of the associated coal plant in the property, plant and equipment (PP&E) accounts, or if associated with a retired coal plant, recorded in regulatory assets." Finally, the letter noted that "[c]onsistent with the requirements of the Commission's Order dated August 8, 2003 in Docket No. E-7, Sub 723 all income statement impacts relating to the AROs ultimately reside in regulatory asset accounts."

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[2] *Id.* at 289.

Q. WHAT ACTIONS WERE TAKEN IN RESPONSE TO THE LETTER?

A. The Commission established Docket No. E-7, Sub 1110 on March 28, 2016 and placed the Letter, referred to as the Savoy Letter, in that docket. In its Order in Docket No. E-7, Sub 1146, the Commission explains that Docket No. E-7, Sub 1110 was opened "so as to acknowledge the letter and allow parties with interest to be made aware of it." The Commission went on to explain that "no filings were made in response to the letter as of the time the Docket was established, and indeed, no substantive filings were made thereafter until the Company filed its petition for Accounting Order on December 30, 2016, formally seeking deferral of coal ash basin closure costs." This all supports the conclusion that the Company's required treatment of these costs was well understood from the outset. Specifically, the Commission stated in its Order the following:

> No party takes issue with the Company's accounting of coal ash basin closure costs in an ARO, as detailed in the Savoy Letter. Certainly, the Public Staff does not – witness Maness' testimony does not challenge the basis for or the propriety of the accounting treatment, he comes to a different conclusion regarding the effect of such treatment upon the Company's entitlement versus its eligibility to earn a return on the unamortized balance of those costs. As noted previously, Interveners have a burden of production when challenging the Company's costs. This principle equally applies to the accounting costs. The Commission determines that the Company has met this burden. The Public Staff challenge makes the issue ripe for the Commission to address the issue on the merits. The Company has met its burden of showing that the costs it seeks to recover are not only reasonably and prudently incurred, but also appropriately accounted for in ARO accounting, and the Commission agrees that based on its

> determinations on the merits that recovery is appropriate except as addressed below.
>
> Several consequences flow from this determination. First, deferred costs are costs "that have been paid for by the …[utility] but have yet to be included for ratemaking purposes …"Lesser & Giacchino, p 52. Through the Savoy Letter, the Company told the Commission and the Public Staff, and the Commission told all interested parties, exactly how the Company's coal ash basin closure costs were being accounted for, and explicitly indicated that the costs were being deferred pursuant to the Commission's orders in Docket No. E-7, Sub 723. Neither the Public Staff nor anyone else, including the AGO, raised objection.
>
> Nor did the Public Staff or AGO raise any objection when the Company made its formal deferral request in 2016. TR. Vol. 9, p.126. The Public Staff however asserts that deferral for regulatory accounting purposes is appropriate, given the magnitude of the costs and their potential impact upon the authorized rate of return. The nature of the deferral is such that all costs, no matter how classified, related to the Company's coal ash basin closure obligations are accounted for in the ARO. Id. P.125. The ARO was established for this purpose, as the Savoy Letter makes clear. As such, the Commission determines that even were it necessary to resolve this issue, witness Maness' classification of these costs as "deferred expenses" is not persuasive, not supported by authority and not determinative, given the nature of deferral.[3]

Q. DO YOU AGREE WITH MR. MANESS' CONCLUSION THAT THE COAL ASH DISPOSAL COSTS THAT DE CAROLINAS IS SEEKING TO RECOVER IN THIS CASE ARE NOT CHARACTERISTIC OF ASSETS RECORDED AS USED AND USEFUL PROPERTY?

A. No, I do not. I believe the costs incurred (relating to the deferred depreciation and accretion) are used and useful as those costs are reasonable and prudently

[3] *Id.*

incurred and are intended to provide utility service in the present or in the future through achieving their intended purpose: environmental compliance, the retirement of the ash impoundments and the final storage location for the residuals from the generation of electricity. The achievement of those three purposes is used and useful as the utility has the obligation to comply with CAMA and the CCR Rule. DE Carolinas Witness Jane McManeus further discusses in her rebuttal testimony that the deferred coal ash costs were funded with investor supplied funds which is the characteristic which makes the inclusion of this cost in rate base legitimate as the Commission previously found in the 2018 Rate Order.

IV. RESPONSE TO PUBLIC STAFF WITNESS METZ

Q. PLEASE DISCUSS WITNESS METZ'S CONCERN WITH PLACING BELEWS CREEK UNIT 1 DFO INTO RATE BASE.

A. Witness Metz recommends the Belews Creek Unit 1 DFO project costs be disallowed in this case because the project is "not commercially operational and is unlikely to be prior to the close of the hearing in this case, and is not used and useful in providing utility service to customers."[4] In coming to his conclusion that the unit should not be placed in service and included in rate base, witness Metz places particular emphasis on the timing for commercial dispatch of the Belew's Creek Unit 1 DFO Project.

[4] Testimony of Dustin Metz at 8-12.

Q. WHY DID DE CAROLINAS PLACE THE BELEWS CREEK UNIT 1 DFO PROJECT IN SERVICE?

A. As discussed in the rebuttal testimony of Company witness Steve Immel, the Belews Creek Unit 1 DFO project was functionally tested in December 2019 and determined to be ready for service on January 10, 2020, when the unit was brought on line using a combination of gas and coal. At that time, the operations team notified the Finance team and the project was moved to Electric Plant in Service.

Q. CAN YOU PLEASE ELABORATE ON THE ACCOUNTING GUIDELINES THAT SUPPORT THE PLACEMENT OF THE BELEWS CREEK UNIT 1 DFO PROJECT IN SERVICE?

A. Yes. In determining when an asset is to be placed in service, DE Carolinas relies on the FERC guidance regarding when a company is to discontinue the accruing of Allowance for Funds Used During Construction ("AFUDC"). The applicable FERC guidance, outlined in 18 C.F.R., Part 101, Instruction 17, provides, in applicable part, that:

> When a part only of a plant or project is placed in operation or is completed and ready for service but the construction work as a whole is incomplete, that part of the cost of the property placed in operation or ready for service, shall be treated as Electric Plant in Service and allowance for funds used during construction thereon as a charge to construction shall cease.[5]

In accordance with the guidelines above, the Belews Creek Unit 1 DFO project was moved to Electric Plant in Service on January 10, 2020, which is

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[5] *See* 18 C.F.R. Pt. 101 Electric Plant Instruction No.3(A)(17)(2019).

the date that it was deemed to be ready for service and placed in operation by the project team. The emphasis being that the DFO project was in operation and Belews Creek Unit 1 was able to, and in fact did, generate on natural gas.

Q. IS THERE OTHER GUIDANCE THAT THE COMPANY CONSIDERED IN MAKING THE DETERMINATION TO PLACE THE BELEWS CREEK UNIT 1 DFO PROJECT IN SERVICE?

A. Yes. In addition to the guidance above, DE Carolinas followed FERC guidance pertaining to the treatment of assets common to multiple units at the same site. 18 C.F.R. § 35.25, in applicable part, provides that:

> Work orders shall be cleared from this account as soon as practicable after completion of the job. Further, if a project, such as a hydroelectric project, a steam station or a transmission line, is designed to consist of two or more units or circuits which may be placed in-service at different dates, <u>any expenditures which are common to and which will be used in the operation of the project as a whole shall be included in electric plant in-service upon the completion and the readiness for service of the first unit.</u> Any expenditures which are identified exclusively with units of property not yet in-service shall be included in this account. (emphasis added).

Based on this guidance, the common assets that will support both Unit 1 and Unit 2 were placed in service at the same time as the Belews Creek Unit 1 project.

Q. DOES THE FACT THAT TESTING IS ONGOING EFFECT THE DESIGNATION OF EQUIPMENT AS IN SERVICE FOR FERC ACCOUNTING PURPOSES?

A. Mr. Metz seems to suggest in his testimony that because testing was ongoing with the Belews Creek Unit 1 DFO project that such is determinative of whether the equipment itself is in service. Mr. Metz's perspective is not supported by the FERC Accounting guidance that specifically anticipates that testing will continue even after equipment in placed in FERC accounts 101 or 106. Specifically, 18 C.F.R. Part 101 provides, in applicable part, the following:

> The cost of efficiency or other tests made subsequent to the date equipment becomes available for service shall be charged to the appropriate expense accounts, except that <u>tests to determine whether equipment meets the specifications and requirements as to efficiency, performance, etc., guaranteed by manufacturers, made after operations have commenced and within the period specified in the agreement or contract of purchase may be charged to the appropriate electric plant account</u>. (emphasis added).

As provided above, testing occurring after equipment has been moved to FERC Account 101 or 106 does occur and is accounted for in the appropriate electric plant accounts. I am not providing testimony on the type or manner of testing being performed: I will defer to DE Carolinas witness Steve Immel on all aspects of testing and related development activity for the Belews Creek Unit 1 DFO Project.

Q DOES THE CONCEPT OF COMMERCIAL OPERATION AND ECONOMIC DISPATCHABILITY FACTOR INTO THE DETERMINATION OF IN SERVICE DATE ?

A. Commercial operation and thereby dispatchability can be a factor when DE Carolinas is placing a new generating unit into service for the first time. Regarding the Belews Creek Unit 1 DFO Project, Belews Creek Unit 1 is already in service. The additions being made in this case are for the additional equipment necessary to co-fire the unit on natural gas. The requirements for placing that equipment in service are prescribed by the FERC guidance I discussed previously and were properly followed by DE Carolinas regarding the Belews Creek Unit 1 DFO project.

Q WAS THIS SAME GUIDANCE APPLIED TO DE CAROLINAS' OTHER DFO PROJECT AT CLIFFSIDE?

A. Yes.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Q. Mr. Doss, did you also cause to be prefiled in this docket, supplemental testimony consisting of eight pages?

A. Yes.

Q. Do you have any changes or corrections to your supplemental testimony?

A. No, I do not.

Q. If I asked you the same questions today, would your answers be the same?

A. Yes.

Q. Did you also cause to be prefiled, Doss Supplemental Exhibit 1 to your supplemental testimony?

A. Yes.

Q. Do you have any changes or corrections that you need to make to your prefiled Supplemental Exhibit 1?

A. No, I do not.

MR. MARZO: Chair Mitchell, at this time I would ask that Mr. Doss' prefiled supplemental testimony as well as his prefiled supplemental -- I'm sorry, his prefiled supplemental testimony as well as his prefiled Supplemental Exhibit 1 be marked for -- well, his prefiled supplemental testimony be read as if it was given orally here today, and Supplemental Exhibit 1 be marked for identification.

CHAIR MITCHELL: All right. Mr. Doss' supplemental testimony will be copied into the record as if given orally from the stand. The exhibit to that testimony will be marked for identification as it was when prefiled.

MR. MARZO: Thank you, Chair Mitchell.

(Doss Supplemental Exhibit 1 was identified as it was marked when prefiled.)

(Whereupon, the prefiled supplemental testimony of David L. Doss, Jr. was copied into the record as if given orally from the stand.)

I. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David L. Doss Jr., and my business address is 550 South Tryon Street, Charlotte, North Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy Business Services, LLC, a service company affiliate of Duke Energy Carolinas, LLC ("DE Carolinas" or the "Company"), as Director of Asset Accounting. DE Carolinas is a subsidiary of Duke Energy Corporation (together with its subsidiaries "Duke Energy").

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed rebuttal testimony and one exhibit on March 4, 2020.

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony is in response to the July 23, 2020 order issued by the Commission requiring that DE Carolinas and Duke Energy Progress, LLC ("DE Progress") file additional testimony in their currently pending rate cases responding to the Commission's request for information on coal combustion residual costs. *See Order Requiring Duke Energy Carolinas, LLC and Duke Energy Progress, LLC to File Additional Testimony on Grid Improvement Plans and Coal Combustion Residual Costs* (the "Order"). My testimony provides the Commission with information concerning the manner in which the Company classifies costs incurred or to be incurred in connection with the Company's ongoing legal obligations, imposed by federal and North Carolina law, to close ash basins at its coal-fired generating plants. Among other uses, these basins either are (in the case of currently operating plants) or were (in the case of recently closed plants) used to store coal ash generated as a byproduct of the combustion of coal. Coal combustion was (or, in the case of currently operating plants, is) the process used at these plants to generate electricity for the Company's customers.

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR REBUTTAL TESTIMONY?

A. Yes. I am sponsoring one exhibit, which was prepared at my direction and under my supervision.

III. <u>RESPONSE TO THE ORDER</u>

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR TESTIMONY.

A. As I describe in detail in my Rebuttal Testimony, the costs incurred in connection with coal ash basin closure activities undergo rigorous evaluation to ensure they are properly classified under accounting rules. Specifically, my Rebuttal Testimony notes:

> DE Carolinas has … implemented a Coal Ash ARO charging committee whose purpose is to evaluate costs to be incurred for determination as to whether they qualify for ARO accounting treatment. The Committee utilizes the guidance in ASC 410, other GAAP, FERC and Commission guidance and Duke Energy Corporation accounting policies to make these determinations. Specifically, for example, the

> Committee utilizes ASC 410-20-55-13 to determine the extent of costs to include in the ARO. Decisions of the Coal Ash ARO charging committee are summarized in a charging guidelines document.

(*See* Doss Rebuttal Testimony at 8.) I have reviewed the Supplemental Testimony of Jessica Bednarcik, including Supplemental Exhibit 1 to that testimony. Witness Bednarcik's Supplemental Testimony notes that the activities identified in Supplemental Exhibit 1 were charged to "ARO," meaning that under the charging guidelines they were classified as Asset Retirement Obligations ("ARO"). As such, the costs incurred in connection with the activites I reviewed would properly be capitalized costs. As I explained in my Rebuttal Testimony, under Financial Accounting Stanadrds Board ("FASB") and Federal Energy Regulatory Commission ("FERC") guidance, ARO costs are an integral part of the plant asset that gives rise to the ARO, and therefore must be capitalized as part of such asset when the ARO liability is recognized.

Q. HAS THE COMMISSION SPOKEN TO THIS ISSUE AS WELL?

A. Yes. In the *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction* entered on June 22, 2018 in Docket No. E-7, Sub 1146, which was DE Carolinas' 2017 rate case ("DE Carolinas 2018 Rate Order"), the Commission acknowledged that both GAAP and FERC accounting guidance required the Company to recognize an ARO upon becoming subject to the legal obligation to retire its ash basins. *Id.* at 288. The Commission further acknowledged that "recognition of the liability carries with it recognition of a corresponding asset – the capitalized cost of settling the liability, which under both GAAP and FERC rules is considered part of the property, plant and equipment for the assets that must be retired." *Id.*.

Q. ARE THERE SOME ACTIVITIES THAT ARE UNDERTAKEN TO SUPPORT COAL ASH BASIN CLOSURE THAT ARE NOT CAPITALIZED AS PART OF THE ARO?

A. Yes. The charging guidelines provide a list of the activities undertaken to close DE Carolinas' ash basins along with the designated charging categories determined by the ARO charging committee. The guidelines identify, for charging purposes, activities as ARO, Non-ARO capital, operations and maintenance ("O&M") costs or some combination. Doss DEC Supplemental Exhibit 1 provides an example of costs evaluated by the Coal Ash charging committee and the associated accounting determination. This information was also provided as an attachment in response to Public Staff data request 159-2.

Q. PLEASE EXPLAIN MORE ABOUT THE CHARGING COMMITTEE'S ROLE IN DESIGNATING THE APPRORIATE CATEGORY FOR COAL ASH REMEDIATION ACTIVITIES.

A. As I discuss in my rebuttal, the Coal Ash ARO charging committee's purpose is to evaluate costs to be incurred to determine whether they qualify for ARO accounting treatment. The charging committee utilizes the guidance in ASC 410, other GAAP, FERC and Commission guidance and Duke Energy

Corporation accounting policies to make these determinations. In the *DE Carolinas 2018 Rate Order*, the Commission discussed these processes as follows:

> DEC has implemented a Coal Ash ARO charging committee whose purpose is to evaluate costs to be incurred for determination as to whether they qualify for ARO accounting treatment..[and that decisions] of the Coal Ash ARO charging Committee are summarized in a charging guidelines document document. Id. at 66-67. These decisions are reviewed internally by the Company's Coal Combustion Products (CCP) group to ensure that 1) all relevant facts were appropriately communicated by CCP and understood by the Committee, and 2) that the CCP group understands the decisions to properly categorize actual project costs." *Id.* at 286.

Q. FOR ACTIVITES THAT ARE DESIGNATED AS AROs IS THERE ANY SUBDESIGNATION OF THOSE ACTIVITIES AS CAPITAL OR O&M?

A. No. The charging committee evaluates expenditures based on the current accounting guidance and policies in place, and under current GAAP and FERC ARO accounting guidance the costs associated with activities that are designated as AROs are capitalized as part of the property, plant, and equipment for the assets which must be eventually retired. As with any other costs that are capitalized as part of property, plant, and equipment, there is no GAAP or FERC requirement to subdesignate the ARO costs to reflect how they would have been accounted for had they not been capitalized. Therefore, the Company's accounting systems and processes are not designed to facilitate such subdesignations or produce financial statement data under an alternative accounting model that is not reflective of current GAAP and FERC rules. As I discuss in my rebuttal testimony, in the *DE Carolinas 2018 Rate Order*, the Commission addressed this issue and found that, under GAAP, the costs (no matter what their classification), are capitalized pursuant to ASC 410-20-25-5. Under FERC accounting, they are capitalized as well. Accordingly, 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. The Commission further concluded that "The nomenclature relied upon in GAAP and FERC is costs, assets, and liabilities, not expenses."

Q. **CAN YOU ELABORATE ON HOW CATEGORIZING THE NATURE OF THE ACTIVITY CANNOT BE SEPARATED FROM GUIDANCE UNDER GAAP, FERC, COMMISSION REQUIREMENTS AND DE CAROLINAS' OWN ACCOUNTING POLICIES?**

A. Yes. The classification of an expenditure is explicitly dependent upon the purpose of the activity, the existing GAAP and FERC guidance, and existing Commission rulings at the time that determination is being made. For example, current GAAP and FERC ARO guidance recognizes that a legal obligation was created and that an ARO liability and offsetting ARO asset needed to be recorded to the Company's books when the CCR Rule and CAMA went into effect. In the absence of GAAP and FERC ARO accounting requirements, there would have been no legal obligation to record when these regulations were enacted. Instead, the costs would have been recorded as they were incurred, and assessed for the proper accounting classification based on the particular activity and the accounting guidance and Commission rulings that would have been in place at the time, in the absence of ARO accounting rules. It is difficult to speculate how accounting rules and Commission guidance may have evolved in the absence of the ARO accounting model. Thus, not only is DE Carolinas' accounting system incapable of facilitating a retroactive removal of accounting guidance, a retroactive assessment of what designation other than ARO might be appropriate for a particular activity would be pure speculation.

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL TESTIMONY?

A. Yes.

Q. Mr. Doss, did you prepare a summary of your testimony?

A. Yes, I did.

MR. MARZO: Okay. Chair Mitchell, I would ask that the summary that has been provided to the Commission and the parties to these dockets, as required by the Commission's order, that that summary be entered into the record as if it was given orally.

CHAIR MITCHELL: All right. Hearing no arbitration to that motion, Mr. Marzo, it's allowed.

(Whereupon, the prefiled summary of testimony of David L. Doss, Jr. was copied into the record as if given orally from the stand.)

Duke Energy Carolinas, LLC
Summary of Rebuttal Testimony of David L. Doss Jr.
Docket No. E-7, Sub 1214

My rebuttal testimony responds to Public Staff witnesses Michael C. Maness. and Dustin R. Metz. Since the filing of my testimony, the issue raised by Mr. Metz regarding the Belews Creek DFO project in service date has been resolved. Regarding Mr. Maness, he asserts that the Company has "chosen" to request a regulatory accounting and ratemaking method that accounts for coal ash compliance costs as ongoing expenses, with a proposed regulatory asset intended to provide for the recovery of expenses incurred in the past that would ordinarily be immediately written off. However, Mr. Maness incorrectly characterizes the facts upon which the Company's Asset Retirement Obligation ("ARO") accounting is based.

As I explain in my rebuttal, the Company was required to adhere to and apply the accounting guidance under the Financial Accounting Standards Board's ("FASB"), Generally Accepted Accounting Principles ("GAAP"), and the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts, as well as Orders of this Commission. The Company evaluated GAAP and FERC guidance in light of the legal obligations imposed upon it by North Carolina's Coal Ash Management Act ("CAMA"), and the Environmental Protection Agency's ("EPA") Coal Combustion Residuals Rule ("CCR Rule"), which was promulgated in 2015. The Company determined that the coal ash basins it operated at its coal-fired generating facilities needed to be closed as a result of the passage of CAMA and the CCR Rule. The closure obligation triggered ARO accounting requirements. In addition, the Commission's Order entered in the Company's E-7, Sub 723 Docket has required the ARO accounting impacts to be deferred into regulatory assets.

By characterizing coal ash ARO related costs as expenses, witness Maness ignores the fact that both the FASB and FERC have ruled that asset retirement costs are an integral part of the plant asset that gives rise to the ARO, and therefore must be capitalized as part of such asset. Mr.

Duke Energy Carolinas, LLC
Summary of Rebuttal Testimony of David L. Doss Jr.
Docket No. E-7, Sub 1214

Maness made similar arguments in the Company's last rate case and the Commission found that under GAAP, the costs (no matter what their classification), are capitalized pursuant to ASC 410-20-25-5. Under FERC accounting, they are capitalized as well. Accordingly, 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. Thus, as the Commission concluded in its Order in DE Carolinas' last rate case, "witness Maness' classification of these costs as "deferred expenses" is not persuasive, not supported by authority and not determinative, given the nature of deferral," and "[i]t is also incorrect as a matter of accounting."

Additionally, I explain that the deferral of coal ash ARO related costs was not a choice. The Company simply accounted for these costs as required under GAAP and FERC Uniform System of Accounts. Further, as it was authorized to do by the Commission, the Company deferred the impacts of ARO accounting, and now seeks an order from the Commission with regards to recovery.

Finally Commissioners, I respond to Mr. Maness's assertion that coal ash ARO costs are not characteristic of assets recorded as used and useful property. I explain in my rebuttal that the costs incurred (relating to the deferred depreciation and accretion) are used and useful as those costs are reasonable and prudently incurred and are intended to provide utility service in the present or in the future through achieving their intended purpose: environmental compliance, the retirement of the ash impoundments and the final storage location for the residuals from the generation of electricity.

MR. MARZO: Thank you, Chair Mitchell. Chair Mitchell, Mr. Doss is available for cross examination.

CHAIR MITCHELL: All right. Public Staff, you may proceed.

MR. DODGE: Good afternoon, Chair Mitchell. This is Tim Dodge with the Public Staff. Before we begin with our cross examination of this panel, I wanted to note, in the witness list and attorney cross examining list for this panel, we had requested three attorneys be provided the opportunity to cross examine two witnesses, to cross examine Mr. Spanos and Mr. Doss.

And the Public Staff discussed this issue with Duke's attorneys and explained that, due to Mr. Doss responding to multiple Public Staff witnesses, and the issues in his rebuttal testimony that had been handled by different Public Staff attorneys, that we agreed that my cross examination today would be related only to Mr. Spanos' rebuttal of the depreciation issues raised by Public Staff witness McCullar, and Ms. Holt will discuss the issues raised in Public Staff witness Boswell and Maness' testimony with Mr. Spanos, if that's acceptable.

CHAIR MITCHELL: All right. It is acceptable, Mr. Dodge. You-all may proceed.

MR. DODGE: All right. And Mr. Grantmyre's questions, I believe, are directed to Mr. Doss primarily.

CROSS EXAMINATION BY MR. DODGE:

Q. Good afternoon, Mr. Spanos, how are you?

A. (John J. Spanos) Good afternoon. Thank you, very good.

Q. I'd like to talk to you first today about the contingency component included in the decommissioning estimates for DEC's power plants.

In the 2018 rate case that I'll refer to as the Sub 1146 proceeding, the Commission approved a 10 percent contingency in that proceeding as opposed to the 20 percent that was recommended by DEC in that case; is that correct?

A. That is correct.

Q. Okay. And can you turn to page 5 of your rebuttal testimony.

A. I am there.

Q. All right. And at the top of the page, you indicate that you were again recommending a 20 percent contingency component; is that correct?

A. Yes. I recommended the -- back to the 20 percent contingency component because, based on what we have learned since that last time in other scenarios where contingencies are -- have been included, we've seen that 20 percent contingency has become more appropriate than the 10 percent. So -- and utilized in my depreciation study, we went back to the 20 percent, because it was more appropriate given the additional information we have in the industry.

Q. Now, in the footnote 1 that's also right there at the top of page 5, you cite back, however, to the rebuttal testimony of Duke witness Kopp from the Sub 1146 proceeding; do you not?

A. That's correct.

Q. And his use of the decommissioning cost estimate study in that proceeding?

A. Yes. He prepared that study, and I utilized it in my depreciation study, that's correct.

Q. Right. And do you have Public Staff witness McCullar's testimony with you today?

A. I do.

Q. All right. I'm going to ask you briefly about the confidential Exhibit RMM-2; however, I just note for the record, the contents of this data response were confidential. I just want to confirm that the study that's referred to in that data response is not confidential. But -- or the title of the study is not confidential. I'm not going to be getting into any of the confidential details in that study.

But would you agree that the confidential Exhibit RMM-2 included in Public Staff witness McCullar's testimony is that same 2016 study that was prepared by Mr. Kopp in the 2018 DEC rate case?

A. Sorry, just one minute, I'm making sure I'm getting to the right spot.

Q. Sure. Yeah, sorry. Let me know when you're there.

A. Yes. I am here with that particular document. And from what I can see in the document, RMM-2 represents the April 19, 2017, decommissioning study that was performed by Burns & McDonnell for Duke Energy Carolinas.

Q. All right. And so while you mentioned just a few moments ago, and I note in your summary today you also note recent experience in the industry supporting this 20 percent contingency, you didn't cite any other sources in your rebuttal testimony or in discovery provide additional support for returning to the 20 percent contingency, did you?

A. No. The comment that I made was that, based on what we have found over the two years since this particular study was performed and what we incorporated in the depreciation study in this particular case for Duke Carolina, we've learned in those two years that contingency estimates have been understated.

So there isn't any specific breakdown of costs that -- that I supplied in my rebuttal testimony. That's just experience from seeing others in the industry as to the overall costs that have been incurred once estimates have actually become more factual, because we have more and more facilities that have been decommissioned over the last couple of years.

Q. All right. Thank you. So let's move on to future net salvage recommendations that you make in your testimony. And first in the context of mass property accounts. Can you turn to page 9 of your rebuttal testimony?

A. I am there.

Q. All right. Now, starting on line 9, you state the following, and I'll just read this:

"For mass property accounts such as those for transmission and distribution plan, net salvage estimates are based in part on statistical analysis of historical net salvage data. In this analysis, net salvage, as well as its components of gross salvage and cost of removal, are expressed as a percentage of retirements. This approach, which is widely accepted in the industry and supported by depreciation textbooks, is referred to as the traditional method."

Did I read that correctly?

A. You did read that correctly, yes.

Q. So other than the part that's based on statistical analysis of historic net salvage data, on what are the information are the net salvage estimates based?

A. Well, as I discuss in part 4 of my depreciation study, all the factors that are in play when properly following the guidelines of developing net salvage percents, things such as industry expectations, specific plans and estimates that the Company will do for each of the asset classes as far as removal of their assets, or a better statement of cost of retiring of their assets, what potential gross salvage they may receive from any specific assets, and then obviously what the current estimate in place has been as to what was agreed upon in the past. So those are some of the factors that come into play along with the statistical analysis.

Now, in part 8 of the depreciation study, we show the statistical analysis so that we have our support. But all of the factors that I just mentioned, which are discussed in part 4 of my depreciation study, and what follows the guidelines in authoritative text, are what is the basis for the net salvage percent for each account. And that's mass property accounts as well as the interim net salvage component for production accounts.

Q. All right. Thank you. And so with regard to the statistical analysis, should it focus on the entire historic net salvage data available, or should weight be given to the more recent analysis?

A. Well, again, informed judgment, which is the component outside the statistical analysis, you need to extrapolate the information based on what you learned from conducting studies. So the overall analysis is part of what you consider, the five-year or more recent analysis should be considered, as well as the rolling three-year averages that we've presented in the depreciation study.

I think once thing that we must incorporate when using our judgment is are all costs recorded at the same exact time. There are at times costs to retire and gross salvage that are not recorded the same exact year that the retirement occurs because of how things are booked. So you have to consider those things instead of just blindly looking at the statistical analysis, whether it be the overall period or those rolling averages.

So in each category, depending on the assets and what you learned from the Company and doing studies within the industry, you're able to come up with the most appropriate net salvage percent that would incorporate not only the overall but also the most recent, as well as what's expected in the future. Because the net salvage percent that you determine is what we expect to happen going forward, so we can't just focus on just the past.

Q. All right. Thank you. Let's go ahead and turn back to page 7 of your testimony briefly.

A. I am there.

Q. All right. So on line 17, you describe Public Staff witness McCullar's recommendation for a less negative net salvage estimate for account 366, underground conduit, in which you say, and I'm reading again from -- now from line 20 on page 7 through line 2 on page 8 that:

"Witness McCullar does not provide any statistical basis for her proposal, other than to compare her results to the Company's recently recorded costs."

Would you agree that Ms. McCullar recommended a net salvage -- excuse me, a net salvage percent for account 366 of negative 10 percent as opposed to the negative 15 percent recommendation, and again, assuming the study on which your recommendation is based?

A. Ms. McCullar has recommended negative 10 for this particular account, and I have recommended minus 15 for this account, which is consistent with the current estimate that was approved in the 2016 study.

Q. All right. And this is discussed in your testimony as well.

Would you agree that the summary of the book salvage in the Gannett and Fleming -- or Gannett Fleming study, excuse me, found a negative 21 percent net salvage percentage for the period 2003 to 2018; but then over a five-year average, negative 9 percent for the period 2014 to 2018?

A. The statistical numbers that you laid out are accurate based on, again, what we've presented in the study. And this is exactly why I emphasize that we need to incorporate informed judgment. And the fact that, as I mentioned in my testimony, that there were some recent gross salvage amounts that were not considered to be commonly occurring for all retirements going forward.

And so when you look at the most recent period of time, cost of removal has gone from minus 30 to minus 40, and the gross salvage that we don't anticipate being as consistent in the last few years is that plus 30 percent, but it's -- without that being a consistent factor, that most recent time period is not necessarily as appropriate for the overall future expectation for conduit.

Conduit is an asset that generally does not get pulled out of the ground. So the salvage value of that will not continue to occur. Which is why, when incorporating informed judgment with the statistics, that minus 21 over the long period of time is more representative as compared to the most recent five-year period of time. However, minus 15 was considered to not ignore the fact that there was salvage value, and to incorporate the overall facts that costs to retire are continuing to go up.

So you can't necessarily reduce the net salvage percent from its currently approved minus 15 to minus 10 when not completely understanding all of the data that you're reviewing. And that's why minus 15 is the most appropriate in my opinion.

Q. Thank you. Mr. Spanos, do you have a copy of the Public Staff Potential Cross Exhibit Number 36 available? This is the Kansas State Corporation Commission's February 24, 2020, order.

A. Yes, I have that.

Q. All right.

MR. DODGE: Chair Mitchell, I would ask that Public Staff Exhibit Number 36 be marked as Public Staff Spanos -- excuse me, Spanos Cross Exhibit Number 1 in this proceeding.

CHAIR MITCHELL: All right. The document will be marked Public Staff Spanos Cross Examination Exhibit Number 1.

(Public Staff Spanos Cross Examination Exhibit Number 1 was marked for identification.)

Q. Okay. Mr. Spanos, are you familiar with this case?

A. I was not the depreciation witness in the case, but I am familiar with the case, yes.

Q. All right. Could you turn to paragraph number 52, which is located on page 20 of that exhibit.

A. (Witness peruses document.)

Q. Just let me know when you're there.

A. Yes. I'm just moving a little slower, sorry.

Q. No worries.

A. Okay. I am on page 20, item 52.

Q. All right. And it states that:

"Atmos claims it uses the industry standard method for analyzing net salvage" -- excuse me. Let me restart:

"Atmos claims it uses the industry standard method for analyzing net salvage is to express net salvage and its components cost of removal and gross salvage as a percentage of ratio of retirements; whereas curbs and staff's methodologies consider the level of net salvage recorded in recent years not as a percentage of retirements."

And now turning down to paragraph 54 on a kind of bring -- bring this paragraph back together. In paragraph 54, the Commission makes the determination about relying on this historic versus recent -- how much to rely on those recent years of net salvage that's recorded; does it not?

A. Do you have a specific spot that I should be looking at in that paragraph?

Q. Yeah. I apologize. I kind of massacred that question here. So midway through starting the -- on the right side about midway down the paragraph, it reads:

"Both Staff and Atmos agree that the net salvage analysis should estimate appropriate levels of future net salvage, not solely rely on -- strictly on historic expense levels. When deciding between Atmos and the Staff's net salvage analysis, the Commission finds Staff's approach would best balance the interests of Atmos' current versus future ratepayers."

Do you see that statement?

A. I do.

Q. Okay. All right. So, now, let's turn to page 17 of your rebuttal testimony.

A. I am there.

Q. All right. And on page -- excuse me, on lines 13 through 15, you state that:

"No. The premise of the type of analysis performed by Ms. McCullar is the depreciation accruals for net salvage should be similar to if not the same as net salvage occurred each year."

And again, in this section, we're talking about account 366; is that correct?

A. The -- well, the discussion specifically relates to account 366 since that's the only account Ms. McCullar disagrees with my estimates and methodology. So the next -- that paragraph or Q and A that is listed on that page relates to the concepts, but, in this particular case, it only relates to one account where she has differed from my estimates.

Q. Okay. And actually, that's the point I was going to turn to next. If you could refer to witness McCullar's testimony, the Table 3 which is located on page 33 of witness McCullar's testimony.

A. (Witness peruses document.)

Q. Just let me know when you're there.

A. Sorry, you said page 33?

Q. Page 33, yes. It's the Table 3, comparison of actually incurred net salvage and net salvage and proposed depreciation rates.

A. Sorry, I was trying to do it electronically and it's not working, so I'll --

(Witness peruses document.)

I'm on page 33. Are you looking at Table 3; is that what the reference was?

Q. Yes, yes.

A. Okay. I'm there.

Q. All right. And again, you've already noted that account 366 is the only one in which Ms. McCullar makes a recommendation different from yours on this -- these net salvage percentages.

Looking -- looking at that row, row 3 -- or account 366, do you agree that the annual accrual DEC is proposing for net salvage is about 22.4 times the average amount DEC has actually incurred for net salvage over this five-year period?

A. The amount that is incurred and the amount that is accrued for are different. It says 22.4. That appears to be around the right numbers, as far as percentage-wise. But again, the whole concept of net salvage is to not necessarily match what's incurred versus what is accrued, because the accrual amount is taking care of what's going to happen in the future, and you have an account that is growing.

So just like all the other accounts in this analysis for distribution and within the study, you have to establish an accrual amount that will cover what is going to be incurred into the future because cost removal is an end-of-life piece. So the amount of incurred is related to assets that are 50 or 60 years old. So it's not appropriate to make the comparison of what's accrued versus what's incurred. And to single out one account seems to be, you know, not following the same standards for all accounts together. And that's kind of the issue that we have with account 366.

Q. Okay. And if Ms. McCullar had recommended depreciation accrual that was the same as the net salvage that occurred annually over this five-year period, the ratio she would have proposed would have been 1.0; would it have not?

A. I think that's probably pretty reasonable. But again, that would not be following the proper standards of recovery, and that would be trying to match expense, and that's not appropriate. So it may be that number, but that's not a standard that should be kept in depreciation for developing accruals.

Q. And I agree. But, in fact, Ms. McCullar's recommended adjustment, which is shown at the end of that row for account 366, was still 14.3 times the average annual amount DEC had actually recently incurred for net salvage for this account, was it not?

A. It is. Her percentage would produce $231,000, which, again, is -- you know, that's a representation, but it won't cover what the cost would be at the end of life, which is why the minus 15 is the more appropriate net salvage percent for this particular account based on the overall information and the future plans. It's not, again, just trying to match what the most recent five years were and saying, okay, that's the percentage we want to use.

Q. Now let's turn to page 19 of your rebuttal testimony.

A. (Witness peruses document.)

I am there.

Q. And so starting with the subsection C here of your testimony, you respond to the Public Staff's recommendation that DEC continue to apply a zero percent interim net salvage percent for other production account numbers 342 through 346; is that correct?

A. Yeah. And I want to make sure it's clear that this does not include the rotable parts component of account 343, but otherwise, that is the discussion that's in part C of this testimony is relating to the interim net salvage that's applied to all of the other asset groups. Staff utilizes zero percent, and I use a negative component.

Q. And you note on line 7 there on page 19 that the Public Staff's position is consistent with the position that was adopted by the Commission in the Sub 1146 case, correct?

A. Yes. And as I point out at the bottom there, that the idea is that we're going to reexamine this in the next few cases. Well, obviously, this is one that we're in now, and I've elaborated on why the zero percent is not appropriate based on what we've learned on over the last couple of years since that particular study, and supported the fact that a negative component is appropriate for the interim aspect of these accounts.

So that's why I'm revisiting it as I'm following what was described there at the bottom of my footnote as to what the Commission said should be done. And we have facts that show that it's different than it was, you know, in the 2016 case. And why in that case I use judgment to say what I knew was going to happen, and this is just supporting the fact that it's actually happened. So by having a cost removal component that's greater than gross salvage and why that's appropriate. So that's the crux of this discussion on this section.

Q. All right. And the -- but you had noted on line 6 -- sorry, turning to page 20, line 6 -- that in the previous case we had -- when discussing this topic, that there had been positive net salvage in recent years for these other production accounts. You go on to say that this was likely primarily due to the positive net salvage for rotable parts, as you just described.

A. That's correct. And the point that is very important to understand here is, for the rotable parts, we have a positive 40 percent net salvage component. And that's why I made the comment earlier in the previous question that that particular component should have a positive net salvage. The other components should have a negative net salvage for interim purposes because of the data, when you look at the data and understand the data in place.

So that's the key point. And, obviously, on lines 11 through 17, I elaborate on the data that's occurred over the two years since the last study occurred.

Q. And just to be clear on that rotable parts distinction, are you indicating that the positive net salvage was entirely due to the rotable parts or primarily due?

A. Oh, it's primarily due. There are some positive net salvage, but it is not to the extent that you have cost removal. So as you can see in lines 12 and 13, as an example, there's $1.45 million in cost removal and 45,000 in gross salvage which is not related to rotable parts. So that is an example of positive net salvage that occurs for rotable parts, and that's the distinction I'm trying to make here.

Q. And again, that was the two-year period, the 2017 and 2018 data that you just cited there on lines 11 through 13?

A. That's the additional data that had been booked since the last study. So again, showing that I'm following the guidelines of what the Commission ruled in the last case, you have to show examples as to why there should be a change, and that's what I'm doing here.

Q. So to the extent there had been interim net -- positive interim net salvage during those prior years as discussed in the last case, had the Company overcollected the cost of removal for those accounts?

A. I'm not sure I understand the question. Would you mind rephrasing that, please?

Q. Sure. So again, you refer to the interim net salvage being positive there on line 6 through 8. And so as a result of having that -- during that period of time, the value was zero, or the proved salvage rate was zero.

During that time, was the Company -- since it was experiencing a positive net salvage, was it not arguably overcollecting the cost of removal during that period of time?

A. No. The -- again, understanding the fact that we're dealing with an overall time period of when the assets were put into service to when they get retired, the cost of removal and gross of salvage get recorded directly to accumulated depreciation, which is part of the depreciation rate. And in the case of production accounts, you calculate the interim net salvage percent and the terminal net salvage percent in order to come up with the full weighted net salvage component.

So when you put all that together, you have the overall recovery pattern that should happen over the entire lifecycle of each asset class. So there isn't necessarily an over- or under-recovery scenario with that involved. You're just calculating what has occurred and what should be recovered going forward. So that's kind of the process that is going on in a depreciation calculation.

Q. Sure. And now, on lines 15 through 17, still on page 20, you state that, because interim net salvage has been zero for these accounts, these costs were not recovered over their service lives.

But kind of on that same point that you were just making about looking at all of these costs together over the service lives, even to the extent the Company has experienced negative amounts in the last two -- over the last two-year time period, that would not have adversely affected the Company's reserve position, would it?

A. Well, we are deal with group depreciation, so in this particular account, $1.5 million of cost to removal, and $45,000 is just part of the overall account level. So in that particular sentence on 15 through 17, I am isolating the specific assets, themselves. But there are some assets that get recovered sooner because they get retired sooner. Some assets that go longer. It's all part of group

depreciation and the remaining-life basis.
So when doing your calculation, you are, again, trying to systematically and rationally recover all investment over its entire lifecycle. So there are individual assets that may not be recovered exactly as those individual assets lived, but in total, you are matching that recovery systematically and rationally. And that's what we're trying to explain here.
Q. All right. Thank you. Those are all the questions that I had originally planned to cover with you today, Mr. Spanos, but after reading your summary, I did want to clarify one point.
Do you have a copy of your summary with you?
A. (Pause.)
Sorry, it wasn't right in front of me. I'm going to get it electronically.
Q. And I can read the sentence to you if that's helpful too that I wanted to ask you about.
A. It's just opening up now, so that way I can read it while you're reading it to me, if you like. All right. I'm there.
Q. So the second full paragraph, the second sentence of that paragraph, you state that each of your net salvage calculations and the use of the 15-year

service live for AMI meter depreciation, those are consistent with the accepted depreciation practices and the prior decisions of this Commission. The only exception being the 20 percent contingency factor that we've discussed already today.

But I just wanted to note, as we've already also discussed today, you're also recommending an additional adjustment to the interim salvage estimates for accounts 342 through 346; are you not?

A. The discussion here is the methodology, which is the same. The interim net salvage portion was zero, and I recommended why it should go to a negative component. But again, as I mentioned, that is only a piece of the weighted net salvage percent. So the methodology is the same as to how these -- all the numbers are put together. So that, in my view, the only change that I made from the Commission decision in practice was the 20 percent contingency factor. The net salvage percent on an interim basis for other production was different, but again, I explained why we did that differently based on what the Commission had asked for.

Q. All right. Thank you, Mr. Spanos. Ms. Holt will pick up from here.

A. Thank you.

CROSS EXAMINATION BY MS. HOLT:

Q. Good afternoon, Mr. Spanos.

A. Good afternoon.

Q. I'd like to ask you some questions based on your rebuttal testimony regarding depreciation rates of the Cliffside unit 5 and the Allen power stations on pages 24 to 27 of your testimony.

On page -- beginning on page 25 in your discussion of Public Staff witness Boswell's recommendation, on lines 9 through 25, you state that:

"Public Staff witness Boswell recommended that witness McCullar restore the depreciation rates on the Allen and Cliffside units to the depreciation rates approved in the Company's last rate case in Docket E-7, Sub 1146; and to use currently approved retirement dates with updated calculations of depreciation rates rather than current depreciation rates for these generating units," correct?

A. You generally read that section of my testimony.

Q. Okay. And by current depreciation rates, do you mean the depreciation rates that you calculated in the new depreciation study which use rates as if the units were soon to be retired?

A. Yes. The current approved depreciation rates I'm discussing are what is included in my December 31, 2018, depreciation study that incorporates all the new information that we have regarding to plant in service, accumulated depreciation, life characteristics, net salvage characteristics, and probable retirement dates for generating facilities.

Q. Thank you. And on page 26 of your rebuttal -- and I'll just kind of summarize what you said primarily on lines 8 to 10. You note the reasons why Ms. Boswell stated her recommendation that depreciation rates from the last case be used.

First, you note that Ms. Boswell stated the plant has not actually been retired yet. And in response to this, you state on lines 15 through 16:

"As a matter of principle, the concept Ms. Boswell sets forth does not comport with USOA or with generally accepted depreciation principles."

Now, USOA, does that mean Uniform System of Accounts?

A. Yes, that is correct.

Q. Okay. Now, you also note Ms. Boswell's second reason was that this method is consistent with what the Public Staff has consistently done, which is to leave the depreciation rates set until the date of actual physical retirement, and at the date of actual physical retirement, any remaining net book value will be placed in a regulatory asset account and amortized over an appropriate period to be determined in a future rate case, correct?

A. That has been staff's position, but that's not been necessarily what has been approved and is not following the Uniform System of Accounts, which is recovering over the retirement date while the asset is in service so that you're following the matching principle. So that's kind of the differentiation between what staff has proposed and what has been, one, approved and, two, agreed upon in the last case.

Q. Okay. And along those lines on the top of page 27, you state that:

"While the Public Staff has taken this position in the past, it's inequitable by definition, and the Public Staff's proposal will result in intergenerational inequity."

That is your position, right?

A. That is my position, because you will then have costs that will be still to be recovered on assets that aren't in service any longer. So ratepayers that would be in place afterwards, in my opinion, would be paying for something they didn't receive a benefit for. So that's why I don't view the position of delaying those costs to be appropriate. And again, I'm just following depreciation practices.

Q. Okay. Mr. Spanos, for North Carolina retail regulatory accounting and ratemaking purposes, who sets the rules for DEC's North Carolina retail accounting practices?

A. Are you asking -- is that the Commission that you're asking for?

Q. Yes.

A. I believe the Commission does, and their practices have been generally to follow the Uniform System of Accounts. So, under my experience in other cases, again, there are exceptions which I mention in my testimony, but, in general, they follow the same guidelines that I followed all along through my study.

Q. All right. And would the authority that the Commission bases that on be North Carolina General Statute 62-35, which covers systems of accounts?

MR. JEFFRIES: Chair Mitchell, objection. That's a legal question.

Q. Would you accept that, subject to check?

A. Yes. Subject to check, I don't have that particular number memorized.

Q. Okay.

MS. HOLT: Chair Mitchell, I request that the Commission take judicial notice of North Carolina General Statute 62-35.

CHAIR MITCHELL: The Commission will take judicial notice of the statute.

MS. HOLT: Thank you.

Q. Mr. Spanos, would you agree, subject to check, that Commission rule R8-27, as you stated earlier, provides that the FERC uniform system of accounts is a default system for electric utilities as regulated by this Commission?

A. I'm sorry, I missed a couple of the words there. Would you mind repeating that, please?

Q. Okay. I will.

A. Sorry.

Q. The Commission Rule R8-27 currently provides for the FERC US -- Uniform System of Accounts to be the default system of accounts for electric utilities that are regulated by this Commission?

A. Subject to check, I would agree with that.

Q. Okay. And would you also accept, subject to check, that under this rule, R8-27, future orders and practices of the Commission that conflict with the FERC USOA supersedes the provisions of the FERC US system of accounts for North Carolina jurisdictional purposes?

MR. JEFFRIES: Chair Mitchell, same objection. Ms. Holt's just simply asking Mr. Spanos to give legal conclusions about the Commission's rules and statutes, and they're free to cite that in their brief, but it's an inappropriate question.

CHAIR MITCHELL: All right. Ms. Holt, where are you going with these questions?

MS. HOLT: Well, the basis of Mr. Spanos' position is on the Uniform System of Accounts, and I'm just trying to establish the basis for the -- the accounting rules in North Carolina.

CHAIR MITCHELL: All right. I'm going to overrule the objection. I will allow the questions to proceed. We recognize the witness is not an attorney. The witness may answer appropriately.

THE WITNESS: As I have discussed in my

testimony, there are instances where this may happen when there is a retirement date that's shorter, but under my guidelines and following the proper practices that I should follow according to all authoritative text, my depreciation study should attempt to recover all investment over its useful life. And that's kind of the direction that I have conducted in my practice.

Q. You state in your rebuttal that, as a matter of principle, Ms. Boswell does not -- her position does not comport with the Uniform System of Accounts.

Isn't it true that Ms. Boswell's position does not violate the generally accepted accounting principles or the provisions of the FERC Uniform System of Accounts?

A. The -- when I say the matter of principle, I'm focusing on the matching principle which comes right from the Uniform System of Accounts, which is to match the utilization of the asset with the recovery of the asset. So, in this particular scenario, when we're talking about production facilities, the utilization of the asset is up to the probable retirement date or date that they actually retire the asset, and the recovery should match that.

So that's the principle that I'm discussing in that testimony. And if we are trying to defer that recovery pattern to dates after the asset is out of service, then I view that not meeting the matching principle, which is the concept of my statements.

Q. But it's a principle, not a rule, correct?

A. I think that I, again, state it as a principle, and that's kind of what I suggest to be part of depreciation accounting for regulated utilities. That's what I follow as the practice. So yes, it is a principle, and I -- but I believe that's the appropriate way that utilities should do this in order to make sure that they are matching the recovery to their utilization of assets. And that's the concepts that all authoritative texts follow.

Q. Now, you acknowledge that the Public Staff has taken this position before, and the Commission has provided for costs to be recovered from customers after their assets have been retired, haven't they?

A. That has happened. And I acknowledge that on page 27. Again, that's not something that I would present in a depreciation study, as I'm to follow the practices and principles of what I view to be the appropriate group depreciation accounting that should be followed.

Q. Mr. Spanos, I would like to direct your attention to Public Staff Exhibit 81.

MS. HOLT: And, Chair Mitchell, I would ask that this exhibit be marked Public Staff Spanos Rebuttal Cross Examination Exhibit 2 for identification.

MR. JEFFRIES: I'm sorry, what was the -- was it potential Exhibit 81?

MS. HOLT: Yes.

MR. JEFFRIES: Okay.

Q. Are you there, Mr. Spanos?

A. Yes, I am.

Q. Okay. Now, as you can see, this is the direct testimony of Laura Bateman --

CHAIR MITCHELL: All right. Ms. Holt, just for purposes of the record, the document will be marked as Public Staff Spanos Cross Examination Exhibit Number 2.

MS. HOLT: Yes. Thank you.

(Public Staff Spanos Rebuttal Cross Examination Exhibit Number 2 was marked for identification.)

CHAIR MITCHELL: You may proceed.

Q. Mr. Spanos, as you can see from the caption, this is the direct testimony of Ms. Laura Bateman.

A. Yes.

Q. And this is for actually Duke Energy Progress, correct?

A. Yes. That's what it says.

Q. Okay. Now, if you go to page 2 of Ms. Bateman's testimony, she states her credentials. And she states that she's employed by Duke Energy Carolinas and is providing testimony for Duke Energy Progress; is that correct?

A. I'm assuming you're talking about at the top of her testimony there?

Q. Yes.

A. She says she's the director of rates and regulatory planning, employed by Duke Carolina, and she's testifying on behalf of Duke Progress, yes.

Q. Exactly. Now, wouldn't you say that, since Ms. Bateman is also employed by Duke Energy Carolinas, her recommendations regarding certain principles, circumstances being the same, would be consistent as they relate to Duke Energy Carolinas? Would you agree with that?

A. I think, generally speaking, that the two companies, since the merger, are operating in a similar fashion.

Q. Thank you. And I'd like you to go to page 18 of Ms. Bateman's testimony.

A. I am there.

Q. Okay. And could you read lines 17 through 23 on page 18 through -- 1 through 5 on the next page.

A. Would you mind telling me which -- because my lines don't -- may not be exactly the same. Starting with the words "in order"?

Q. Line 17, "originally."

A. Okay.

Q. Through 18.

A. And then I should go through line 5, you said?

Q. Yes.

A. Okay.

"Originally, the depreciation consultant had proposed new depreciation rates that would fully depreciate the Asheville coal plant by its expected retirement date in 2020. In order to mitigate the impact on customers in this case, DE Progress asked the consultant to adjust the rates to reflect the recovery of the remaining net book value of the Asheville coal plant over a 10-year period, similar to the treatment of other coal plants that were retired early in DE Progress' prior depreciation study. Since under this approach, the net book value of the plant will not be fully recovered at the time of retirement, the Company is requesting permission to establish a regulatory asset at the time of the plant's retirement for the remaining net book value and the ability to continue amortizing the costs over the remaining portion of the 10-year period at that time."

Q. Thank you. Would you characterize Ms. Bateman's recommendation, to establish a regulatory asset and use the same depreciation rates for a plant not yet retired, similar if not the same as witness Boswell's recommendation?

A. It's similar but not necessarily the same. And I say that because of the particular scenario with Asheville being closer to the retirement date of the study date or period of time where the two units or two locations that we're dealing with here were further in the future.

So under the criteria that -- and I talk about this in my testimony, that would be the difference, is that Asheville was being closed much sooner than what the time period was for what we have for Allen and Cliffside 5.

Q. Okay. Thank you. I would like to direct your attention to one more exhibit, Public Staff Proposed Exhibit 82.

MS. HOLT: And, Chair Mitchell, I would ask that this exhibit be marked as Public Staff Spanos Rebuttal Cross Examination Exhibit 3 for identification.

CHAIR MITCHELL: All right. The document will be marked Public Staff Spanos Rebuttal Cross Examination Exhibit Number 3.

(Public Staff Spanos Rebuttal Cross Examination Exhibit Number 3 was marked for identification.)

Q. And just as a matter of identification, this is the testimony of James Horde on behalf of the Public Staff in Docket Number E-2, Sub 1023.

A. That's correct.

Q. Do you see that?

A. Yes, I do.

Q. Okay. Now, on pages 11 to 12, if you go down. And I'll summarize. From pages 11, the end of page 11, lines 20 to 22, would you agree that, in this docket, the Public Staff and Duke Energy Progress agree that the cost of the retired Cape Fear, Lee, Robinson, Weatherspoon, and Morehead City plants could be recovered from ratepayers in the years after they were retired?

A. (Witness peruses document.)

Yeah. That's the discussion that is being set forth on that page.

Q. All right. In your testimony, Mr. Spanos, you state that the Public Staff's treatment to use the estimated retirement dates from the previous depreciation studies will cause intergenerational inequity.

Now, the circumstances in this case are that the Company has determined that the useful lives of the plants in question need to be -- need to be shortened from what they've been in the past, correct?

A. There are some units that need to be shortened from what they've been in the past. Some are the same. So depending on which particular units that you're referencing, that's an accurate statement.

Q. The Cliffside and the Allen units that we're talking about.

A. There are -- yeah, some of the Cliffside 5 and the Allen units, two of the Allen units that are expected to be retired earlier than the probable retirement date that was in place as of the last study.

Q. That's what I'm referring to. Thank you. Now, does that mean -- doesn't that mean that, if the Company's position is adopted by the Commission in this case, customers in the next few years, before the plants are actually retired, will be charged more for depreciation of these plants than customers in the past years have been?

A. They -- again, depreciation studies are based on estimates of knowledge that you have at the time the study is performed. So there was a probable retirement date that was later in time. So under that criteria, again, when doing a systematic and rational recovery pattern and dealing with the remaining life basis, when you change estimates, whether they be longer or shorter, there will be, at that point in time, a difference from past ratepayers. But again, you were trying to recover it systematically from what's left to be recovered.

So under that criteria, if we're just looking at probable retirement dates for those particular two units, then they will be recovered for those -- again, for those specific units at a time that is -- or those ratepayers in the next few years will pay more than what was done in the past. However, again, there are other factors that develop a depreciation rate such as the interim survivor curve, the net salvage percent, and the decommissioning components. All those factors come into play as to what the final amount is to be recovered.

So I think you're missing the concept of intergenerational inequity as to what I'm trying to reference when it's just one component that we're focusing on. There's more to it as to why we divert or defer the costs related to one component on two units versus all of the assets in the account class.

CHAIR MITCHELL: All right. We have come to the end of our day. We will go off the record. We will be in recess until 9:00 tomorrow morning.

(The hearing was adjourned at 4:33 p.m. and set to reconvene at 9:00 a.m. on Tuesday, September 15, 2020.)

CERTIFICATE OF REPORTER

STATE OF NORTH CAROLINA)
COUNTY OF WAKE)

I, Joann Bunze, RPR, the officer before whom the foregoing hearing was taken, do hereby certify that the witnesses whose testimony appear in the foregoing hearing were duly affirmed; that the testimony of said witnesses were taken by me to the best of my ability and thereafter reduced to typewriting under my direction; that I am neither counsel for, related to, nor employed by any of the parties to the action in which this hearing was taken, and further that I am not a relative or employee of any attorney or counsel employed by the parties thereto, nor financially or otherwise interested in the outcome of the action.

This the 16th day of September, 2020.

JOANN BUNZE, RPR
Notary Public #200707300112