PLACE: Held via Videoconference REDACTED

DATE: Wednesday, September 30, 2020

TIME: 9:00 A.M. - 12:30 P.M.

DOCKET NO.: E-2, Sub 1219

E-2, Sub 1193

BEFORE: Commissioner Daniel G. Clodfelter, Presiding

Chair Charlotte A. Mitchell

Commissioner ToNola D. Brown-Bland

Commissioner Lyons Gray

Commissioner Kimberly W. Duffley

Commissioner Jeffrey A. Hughes

Commissioner Floyd B. McKissick, Jr.

IN THE MATTER OF:

DOCKET NO. E-2, SUB 1219

Application by Duke Energy Progress, LLC,

for Adjustment of Rates and Charges Applicable to

Electric Utility Service in North Carolina

and

DOCKET NO. E-2, SUB 1193

Application of Duke Energy Progress, LLC for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego

VOLUME 13

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P R O C E E D I N G S

COMMISSIONER CLODFELTER: Good morning, everyone. We are still on the record, and we have Ms. Bednarcik under oath, and cross examination by Ms. Townsend. Before, Ms. Townsend, you began, I want to revisit again the procedures that we worked out on the fly, as it were, about our numbering convention for exhibits in the case. By and large -- and I thank you all for helping me through that novel experience yesterday. By and large, we got it the way we agreed to do it. We had one glitch, so I want to walk through it again. And that will also help everyone understand what the glitch was, and then we'll get that corrected.

This applies, of course, only to witnesses or panels in this case who also appeared as witnesses or panels in the Duke Energy Carolinas proceeding and whose live testimony in that proceeding is subject to a stipulation concerning use in this case. So it only applies to that group of witnesses or panels who are common to both cases where there is a stipulation concerning the use of their testimony in the Duke Carolinas case in this record.

As we agreed yesterday -- and again, thank you all for following this -- if any exhibits that were used in the Duke Carolinas case for such a witness or such a panel are to be designated and moved into the record in this case, they should retain the same designation that was used in the Duke Carolinas case. Example, Public Staff Exhibit Number -- Cross Examination Exhibit from Ms. Bednarcik Number 1 in the Carolinas case, if it were used in this case by the Public Staff, would be Public Staff Bednarcik Cross Examination Exhibit Number 1, maintaining the same designation.

Now, here's where we get into a little bit of the glitch. An examining party may not use all of the exhibits that it used with such a witness in the Duke Carolinas case. For example, again, let's suppose that, in examining Ms. Bednarcik, the Public Staff had Exhibits 1 through 10 in the Duke Carolinas case, but they intend in this case to mark and use only Exhibits 3 and 7. Those exhibits would be marked and designated in this case as Exhibits 3 and 7 without any prefixes. Again, we cleared up the prefixes issue yesterday. But, of course, the Public Staff would not then be using in this case what were marked and designated Exhibits 1, 2, 4, 5, 6, 8, 9, and 10.

Here's where we need to be careful. If the Public Staff, for example -- I'm not picking on you, Ms. Downey, I'm just using you as an example because you're in the center of my screen. If, for example, in this case with Ms. Bednarcik, the Public Staff now wishes to use a new exhibit that was not previously used in the Duke Carolinas case, the next number in this case would be Public Staff Bednarcik Cross Examination Exhibit 11, 11. So you need to pick up with the last exhibit number that was designated in the Duke Carolinas case regardless of whether it then is used in this case or not, and the first new exhibit in this case bears the next number in sequence.

I think we got that right in all instances yesterday. For example, Mr. Neal, thank you, I think you -- we got it right with you. We got it wrong, Ms. Downey, unfortunately, in one instance with you. And I need your help with this, parties, because I don't have here in front of me the exhibit numbers from the Duke Carolinas case.

And I don't know the last number that was used in this case as I sit here during these proceedings. So I need you to get this right for me.

So in the Duke Carolinas case, with the Hager/Pirro/Huber panel, the Public Staff identified five exhibits.

MS. DOWNEY: Right. That's correct.

COMMISSIONER CLODFELTER: In this case, during the examination of that panel, Hager/Pirro/Huber, the Public Staff designated and moved to admit into the record only Exhibit Number 1 from the prior case.

MS. DOWNEY: That's correct.

COMMISSIONER CLODFELTER: The Public Staff then used a new exhibit with that same panel in this case that had not previously been marked or used in the Duke Carolinas case. That exhibit should have been designated and marked in this case as Hager/Pirro/Huber Public Staff Cross Examination Exhibit 6.

MS. DOWNEY: That's correct, Commissioner Clodfelter. Apologies.

COMMISSIONER CLODFELTER: No, no, no. No one owes apologies to anyone on this. As I say, this is a novel process. We have not done this before. We are going to have to practice it a good bit just to get it so that it is second nature. We are all learning as we go in this exercise.

So, unfortunately, that exhibit got marked as Number 2. And so without objection from the parties, unless there is objection from the parties, we will take that exhibit that was previously marked yesterday as Hager/Pirro/Huber Public Staff Cross Examination Exhibit 2, and it will be redesignated as Number 6. Without objection, we'll do that.

(Hager/Pirro/Huber Public Staff Cross Examination Exhibit 2 was renamed Hager/Pirro/Huber Public Staff Cross Examination Exhibit 6.)

COMMISSIONER CLODFELTER: Now, do we all understand where we are? And, again, as I say, with only one exception on the first day out on the first try, we otherwise got it right, and I thank you all for that. But again, I need you to keep me straight on that, because I don't know which was your last number from the last case. All right?

MS. DOWNEY: Thank you,

Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Thank you all. And with that, I'm sorry for the interruption, Ms. Townsend, Ms. Bednarcik, you two are back at it.

MS. TOWNSEND: Thank you, Commissioner Clodfelter, and good morning, Ms. Bednarcik and everyone else.

Whereupon,

JESSICA L. BEDNARCIK,

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

CONTINUED CROSS EXAMINATION BY MS. TOWNSEND:

Q. We will start with Weatherspoon. That was the other facility that we discussed yesterday that was -- that failed to meet the surface impoundment standard for unstable areas or seismic impact zones, correct?

A. So it was. And just to make sure it's clear what those location standards were. Those were new regulations that were passed in the CCR rule in 2010. So it was a new regulation and new evaluation that needed to be done as part of the CCR rule. They did not indicate anything related to the operations of the basins, itself. So those -- those location restrictions, the only -- the purpose for those was to determine, as part of the CCR rule, whether or not you were to trigger closure underneath the 2015 CCR rule. So that was the purpose of those designations and that was the purpose of doing the evaluations underneath the 2015 rule.

Q. Okay. They were also safety concerns, were they not?

A. So again, they were location restriction designations that were done in order to determine whether or not closure needed to be triggered. Of course, under dam safety rules in North Carolina, there was safety evaluations that were done, and there were evaluations that were also done prior to the federal CCR rule. But specifically when you talk about those designations as part of the CCR rule, I just wanted to make sure that it was clear that the purpose for those was to -- as per CCR, to determine if or not closure was triggered.

Q. Understood, thank you. If you would, go to Hart Exhibit 58, which we have designated as Bednarcik Direct AGO Cross Examination Exhibit Number 14.

A. (Witness peruses document.)

I have that in front of me now.

Q. Thank you. If you would turn to page 1-11.

A. (Witness complies.)

I'm on that page.

Q. Okay. And that is where the CAM reports about the specific issues related to Weatherspoon under the unstable areas or seismic impact zones.

Can you read that for us -- read that and explain to us what the specific issues were at Weatherspoon?

A. Just to clarify, to read it to myself and then --

Q. Yes.

A. Okay. Thank you.

Q. Thank you.

A. (Witness peruses document.)

So I have reviewed that section.

Q. Okay. And what parts of the facility were of concern?

A. So as we had discussed before, the CAMA report does show what the Company already had put out on our public with website and already determined to give it to the -- publish as part of the CCR rule on the public site as well as given to DEQ. It does discuss that the -- the -- the dams associated with the 1978 basin did not meet the initial factor of safety for a seismic event, and also discusses those regulations -- or those location restrictions in the CCR rule.

So it just confirms what I just said, is that we didn't meet those requirements of the new CCR rule, and therefore, we had to initiate closure, which we were doing at that time. And that's -- actually, it also states that that's how we are addressing those issues, is doing closure at the basins.

Q. Okay. But my reading also shows that there is evidently some concern regarding the foundation abutments of the 1979 ash basin that wouldn't be stable during a seismic event; is that also what it says?

A. It does. As part of the CCR rule, when we had to do those evaluations, we -- new rule, new evaluations. We went back and looked at it in order to follow those rules. Came up with a determination that -- basic civil engineers looked at it and said this is why we now are triggering closure and have to move forward.

Q. Okay. So there were the foundation abutments of the 1979 ash basin, and the dikes were constructed of soils that are susceptible to liquefaction, which we discussed yesterday with Sutton; is that right?

A. So that -- when they did the evaluation, and after the 2015 rule, that's what they determined. But again, those basins were constructed and operated under the permit prior to this, so they -- the new evaluation, new rule determined this is just why we went forward in our initiating closure, and actually excavating material out of the Weatherspoon basin.

Q. Okay. If we also look at page 1-3 in the CAM report, it references, again, the 1979 ash basin. And it says that DEP has completed six upgrades to that ash basin over the last five years.

Can you tell us why those upgrades were completed?

A. Ms. Townsend, can you give me the page again? I want to make sure I'm reading the right thing.

Q. Absolutely. It should be 1-3, if I recorded it right. Yes. If you look in the second -- under ash management activities, the second paragraph talks about the fact that they have completed several upgrades to the 1979 ash basin over the last five years, and then it talks about what those upgrades were; do you see that paragraph?

A. Yes, I do see that paragraph.
Q. Okay. And again, can you tell us why those upgrades were completed?
A. So I believe that that paragraph actually describes why those upgrades were completed. Some of it is -- generally. Some of it was to make sure that we had enough room in the basin as we are generating the electricity and generating the product, so to make sure that we had enough drainage in the area. So it talks about having an alternative outflow discharge area within basins when constructing a reverse filter.
So the paragraph that you referenced actually describes what those upgrades were. And later on it says it's either in -- done voluntary by Duke Energy or in accordance with directives from the State of North Carolina to increase the integrity of the 1979 basin.
Q. Okay.
A. So they were necessary upgrades either to maintain operation, to make sure that we had enough room in the basin to continue generating electricity, or as we were doing evaluations of the dams over the years, if we saw things that needed to be fixed working with NCDEQ, we fixed them.

Q. Okay. And again, these were done to increase the integrity of that ash basin, correct?

A. No. Some of them. It does mention that there was some -- that last sentence says there was some that -- integrity, but not all of them. A number of them were to maintain operations. I would have to go back and look at each and every one of them to determine what was what. But I think it's clear that some of the operations, some of the things that were done was to make sure we continue to operate. Some were based upon evaluations of dam safety and modifications that needed to be done.

Q. Okay. It appears, based on the CAM's comment at the very last sentence, that it was to increase the integrity of the 1979 ash basin, that he was maybe misinformed by DEP regarding that?

A. So no, Ms. Townsend, you missed the word "or." There is the word "or" in there. So we either did it voluntarily or because -- or in accordance with directives from the state to increase the integrity of the basin. So when I -- and knowing what those actions are, they're not all for integrity.

Q. Okay. Now let's discuss them. One was reshaping and regrading the slopes on the north end of the basin. What was the purpose of doing that?

A. So, Ms. Townsend, I'd have to go and look at the actual reports of when we did that to see exactly why -- why it was done and whether it was done as part of ensuring that proper operations or related to an evaluation of the dam, itself.

Q. Okay. And you also can't inform us what the approximate cost to each of these upgrades were, can you?

A. No, ma'am. They were done, of course, many years over -- many years ago, and would have been addressed in past rate cases, of course.

Q. Okay. Well, it says over the last five years. So it's certainly -- some of those things occurred during this time period for which we are here, is it not -- were they not?

A. So, Ms. Townsend, thank you for bringing that up. If they were within the last five years -- so right after CAMA was passed, there was a number of upgrades that were done to the basins. Because that was one of the things that we had to do underneath CAMA, was to do a reevaluation of all of our basins. And we did do some dam modifications in response to that. That was all covered in the last rate case, and

Mr. Kerin talked about those extensively. But those costs are not included in the -- in what we are asking as part of this case.

Q. Okay. So none of these upgrades would be in this case; is that correct?

A. I would have to go through each and every one of them. Any type of significant upgrades were done prior to the -- prior to this case. I would have -- there may have been some modifications. We have had some animal borrows that we had to fix, things like that that would be included in this case. But anything that was of any cost was -- one of the first things we did after CAMA was to those projects.

Q. Okay. Going to another subject matter. Are you aware that DEP prepared a significance scoring matrix in 2012 to evaluate the priority of plant environmental impacts based upon the likelihood of occurrence and the consequences?

A. Ms. Townsend, I'm aware of something like that. If you could show me what it is, I would appreciate it.

Q. Absolutely. If you will go to Hart 38.

A. (Witness peruses document.)

I have it open now.

Q. Thank you.

MS. TOWNSEND: Commissioner Clodfelter, we would ask that this be marked as Bednarcik Direct AGO Cross Examination Exhibit Number 28, please.

COMMISSIONER CLODFELTER: It will be so marked.

MS. TOWNSEND: Thank you.

COMMISSIONER CLODFELTER: Spacebar is not working today. Sorry, guys.

MS. TOWNSEND: Understood.

(Bednarcik Direct AGO Cross Examination Exhibit Number 28 was marked for identification.)

MS. TOWNSEND: All right. Again, this is marked confidential; however, we have communicated with Duke, and we are informed by Mr. Mehta that this is no longer considered confidential.

COMMISSIONER CLODFELTER: Mr. Marzo, Mr. Mehta, either one of you just confirm for the record, please.

MR. MARZO: I confirm that, Chair.

COMMISSIONER CLODFELTER: Proceed,

Ms. Townsend.

MS. TOWNSEND: Thank you.

Q. All right. If you can go to the Asheville tab. Do you have that? There's a tab for each of the facilities, obviously.

A. If you get -- the hard copy I have just has all of them put together, so if you give me a moment I will try to pull it up electronically so I can find that tab.

Q. Okay. Thank you.

A. (Witness peruses document.)

Q. And it's the first page of the Asheville tab.

A. It's going to take me a minute. I did not have -- like I said, sorry, it's going to take me a minute to find it electronically. The hard copy I have doesn't show tabs on it, so if you give me just one moment, please.

Q. Sure.

A. (Witness peruses document.)

So, unfortunately, Ms. Townsend, my computer is saying that the file is corrupted. Let me -- if you tell me what the first, maybe secondary activity is in the aspect, I may be able to find it.

Q. Right. Each of the documents that I have that are printed out indicate Asheville plant, and then it talks primary activity, secondary activity, aspect, potential impact, significance ratings, and then comments; do you see that?

A. I do see that. If you give me maybe what the first one is, and then maybe I can find it in this stack here.

Q. Okay. I'm sorry. I didn't mean to interrupt. The first one for Asheville under power plant operations and secondary activities control equipment, aspect has an ESP operations number. And then the potential impact there was positive reduction of error impacts; do you see that?

A. I am hoping I'm looking at the right one that has that on there, so.

Q. All right. The line we're going to talk about is line 3, so if line 3 -- do you see where in the potential impact it says groundwater impact?

A. Yes.

Q. Okay. And as we read across going to the total, the total significant score was 21 for Asheville for groundwater impact, correct?

A. Yes, that's what it says. But I would also say that I'm not as familiar with the evaluation that was done by DEQ. If I had the document that really described how they came up with the likelihood, the exposure, toxicity cost, all of that, that gives some context. So just looking at it right here, I mean, the document says what the document says. Without all that background information, I cannot opine as to how they came up with it and what it might mean, other than what's in the document.

MR. MARZO: Ms. Townsend, you are on mute. We can't hear you.

Q. Sorry. It is a DEP document, not a DEQ document.

A. Okay. I'm sorry. Again, I would -- but whether it's DEP or DEC, I don't have the background. I would have to look in order to describe what was going on here, understanding what the background and how we evaluated this.

Q. Okay.

A. You know, I do -- I have not looked at the document as to how these numbers were put together.

Q. Okay.

MR. MARZO: Ms. Townsend, I might also just interject, not so much an objection, but to notice again, as we discussed yesterday, Mr. Wells is testifying later in this case and can talk about, in detail, some of the groundwater issues that I believe you're raising here.

MS. TOWNSEND: I'm just going through this one document, Mr. Marzo. I'm not going to take a lot of time. I just want to explore what this internal document has to say about the environmental impacts, whether it be groundwater or anything else.

Q. So there is a table which shows us what the various priorities are. Do you see that table? 1 to 7 is lowest priority; 8 to 9, low priority; 10 to 13, moderate priority; and 14 to 25, high priority. Do you see that?

A. (Witness peruses document.)

Ms. Townsend, as I'm flipping through, I don't see it. And like I said, when I tried to pull up the electronic, it told me the file was corrupted, it won't open, so, unfortunately, I can't see that.

Q. We'll do that subject to check. But do you have the key to the significance rating? Can you find that document?

A. (Witness peruses document.)

Ms. Townsend, I do not, I'm sorry. I can't find it in the one that's printed out. And like I said, the file is corrupt. I cannot locate the key.

Q. All right. If I may just for the record, subject to check, indicate just for Asheville --

MR. MARZO: Mr. Chairman, I would just interject here that it's unnecessarily due, the subject to check here. As I mentioned before and several times yesterday, both Ms. Bednarcik and Mr. Wells are testifying in rebuttal. And to the extent we need to make sure this document is available at that point in time, if it's not so for available to Mr. Wells, this question can be asked in a manner that's not subject to check when the Commission can be provided the best information and not simply read the document subject to check.

COMMISSIONER CLODFELTER: Ms. Townsend, Mr. Marzo is offering to bring Ms. Bednarcik back on rebuttal along with Mr. Wells, at which point in time I presume she will have available to her an uncorrupted copy of the document. What say you?

MS. TOWNSEND: I say that's absolutely fine, Commissioner Clodfelter, I have no objection to that.

COMMISSIONER CLODFELTER: All right.

Thank you. And Mr. Marzo, we'll leave it to you to work on getting Ms. Bednarcik a good copy of the document Ms. Townsend is asking about.

MS. TOWNSEND: Thank you.

MR. MARZO: Thank you, Chair Clodfelter. I will make sure that occurs.

COMMISSIONER CLODFELTER: Thank you.

MS. TOWNSEND: And with that, no further questions, Commission Clodfelter. Thank you, Ms. Bednarcik, for your time.

COMMISSIONER CLODFELTER: Okay. Ms. Cralle Jones, I have you next in the batting order; am I correct?

MS. CRALLE JONES: You are. Thank you. Good morning.

CROSS EXAMINATION BY MS. CRALLE JONES:

Q. Good morning, Ms. Bednarcik. I'm Cathy Cralle Jones representing the Sierra Club. It's good to see you again. And just a few questions this morning. We talked in more detail the previous hearing regarding your background, but just to confirm one key date.

It was after the merger with Progress Energy that you became the manager of the remediation and decommissioning group at Duke Energy; correct?

A. Yes.

Q. And so prior to 2013, you would have had no experience with or knowledge of any of the Duke Energy Progress plants; is that correct?

A. I believe that the merger date was in 2012, so although I did take that new role. But I'm going off of memory, I believe the merger was in 2012. I did have some knowledge of the plants. There was some peer groups where I had discussions with members of employees of Duke Energy Progress, but my detailed knowledge was after the merger.

Q. Okay. And -- but prior to 2013, you didn't have any firsthand experience of coal ash management issues at any of the DEP plants; is that correct?

A. I did not have firsthand, but, of course, I -- as I was getting ready for this, I did discuss with people who did have firsthand experience.

Q. Beginning on page 14 through 17 of your direct testimony, you describe the closure activities and related costs at the Mayo and Roxboro plants; is that correct? That full section.

A. (Witness peruses document.)

Can you give me the page number again? I just want to make sure.

Q. Sure. Page 14. Starting at page 14.

A. (Witness peruses document.)

Yes, that is the section where I'm describing the closure activities between September 1, 2017, and February 29, 2020, for Roxboro and Mayo.

Q. Okay. And some of the costs you describe there are related to providing permanent water supplies; is that correct?

A. Yes.

Q. And you were the special assignment leader who managed that project provision of permanent water supplies to resident neighbors; isn't that correct?

A. Yes.

Q. On page 16, line 3, you state that at Mayo and Roxboro, the Company incurred costs to, quote, plan, design, and install permanent water supplies to neighboring residents. And then on line 5, permanent water supply included the planning, design, and installation of municipal water mains and/or service lines; did I read that correctly?

A. Yes. Ms. Cralle Jones, this was -- overall, we did an evaluation for whether we could do a service line or water treatment systems at the Roxboro and Mayo plants. We only moved forward with the installation of water filtration, water treatment systems because the municipality could not move forward and said that, because of a number of reasons, we could not put in a municipal line to those residents.

Q. Okay. But your testimony there points to the design and installation of municipal water mains and service lines, but the Company did not install any municipal mains or water lines in either Mayo or Roxboro, correct?

A. That is correct. And there was no specific costs related to the installation of those lines because they weren't installed and they were not designed.

Q. Okay. On page 26, you offered your opinion that the costs that DEP incurred to close coal ash ponds were reasonably and prudent, and you listed the factors you considered when forming that opinion.

You've got whether the activities performed and to be performed are necessary, whether the cost for the necessary activities are appropriate, and whether the closure projects are meeting Company and regulatory deadlines, correct?

A. Yes.

Q. Other than those three considerations, did you consider any other factors relating to DEP's costs to close coal ash ponds?

A. So, Ms. Cralle Jones, it's a very open-ended question. These are the factors when I was doing the review and getting prepared. These are the main factors. As I sit here today, I don't know if I could rattle off any others, but these are the main ones in order to ensure that what we were asking as part of this case were both prudently incurred and reasonably incurred.

Q. And when forming your opinions about reasonableness and prudence of the DEP expenditures as presented in your direct testimony here, were you looking only at documents post 2018?

A. So the costs that are being incurred and that we are asking for recovery cover for the DEP, specifically the September 1, 2017, through February 29, 2020. So the execution of that work that resulted in the costs that we're asking for recovery. So prior to 2018, yes, anything that was we were asking for cost of recovery, I evaluated those documents.

Q. Did you consult any Company records regarding operation of coal ash plants from before 2018?

A. So I think I just answered that that yes, prior to 2018, I did consult documents for the execution of the work that we are asking for recovery in this rate case.

Q. Okay. Did you or anyone else at the Company ever attempt to evaluate whether current costs would be lower if the Company had switched to dry ash handling earlier at any of the DEP sites?

A. No, ma'am, we did not, because, again, change in regulation, change in rule, new requirements that we had to move forward. The operation of the basins, as we have testified in the DEC case, in the 2017 case, operations of those were done under the rules and regulations at the time that they were constructed and operated.

So the evaluation that I did for the recovery of the costs in this case were based upon how those costs were executed, and addressed, and implemented.

Q. So that would confirm that you did not look at whether or not current costs would be lower if the Company had implemented dry ash handling at the Asheville plant in lieu of constructing that 1982 ash pond?

A. So, Ms. Cralle Jones, of course, what we are to do is to try to evaluate the decisions that are made at the time with the information known at the time. It is impossible to go back and do a hypothetical evaluation of lots of what-ifs. What if we would have done something at some undetermined time in some undetermined area? That is an evaluation that is unfruitful and really doesn't have any -- I would look at it and say no merit, because we moved forward and we executed the work that we needed to execute based upon what we knew at the time that we knew it.

So moving forward with, again, costs that we are asking as part of this case, change in law, change in regulation, new requirements in the Company, we made that determination of what needs to happen, and we're moving forward to execute that work appropriately.

Q. But you could determine the cost related to excavation and closure of the 1982 ash pond, correct?

A. Based upon what the -- what we have today and what we know what the costs are to excavate, we have a cost for it today. What we don't have is -- there's lots of factors, unknown factors that we have to try to take into account looking back so many years. You don't know what the price of steel was, you don't know what the price of labor, you don't know what new regulations would have come through at that time. It is impossible to do a hindsight review and do an evaluation of lots of what-ifs because it's not just a change in one item and looking back in time.

You don't know what -- you don't know what would have happened and what other consequences might have been if we did go to dry ash handling in 19 -- just pick a date. It's impossible to do that type of hindsight review. We did evaluate, when I looked at the information and looking at what I saw what a utility engineer would have known at the time, we executed, we worked, we operated the basins within the rules and regulations at the time. And now, of course, we are new rules, new regulations addressing those appropriately.

Q. And at H.F. Lee plant, there was a 1982 active ash basin constructed. And so I'm assuming there was no evaluation of whether or not current costs would be lower if the Company had implemented dry ash handling at the H.F. Lee plant in lieu of constructing that 1982 ash basin?

A. So no, ma'am, I would say it's the same exact response I just gave you for all of them is, based upon the information we knew at the time, we made the best decisions to move forward to make sure we can provide reliable electricity to our customers. And as you know, the '82 basin, we had a permit to construct that basin from NCDEQ, so, of course, we -- that shows we have always been working with our regulators to make sure we move forward underneath the regulations at the time.

Q. And the same answer I expect would apply for the 1983 ash basin construction at the Mayo plant; is that correct?

MR. MARZO: Mr. Chair, I think that's asked and answered by Ms. Bednarcik.

MS. CRALLE JONES: I'm just asking for each of these plants and the dates. The 1983 Mayo construction, that would be the same response.

COMMISSIONER CLODFELTER: Unless I misunderstand, I think this is a question about a different basin, so I'll allow the question.

MS. CRALLE JONES: My apologies. I jumped ahead.

Q. Can you answer -- would you answer that question? Is that correct, that it would be the same answer?

A. For all of our plants, the construction of the basins and the time periods in which they were constructed, the decisions that were made were based on the information at the time that those decisions were made, so yes.

Q. And then also for the Robinson, South Carolina plant, the 2002 expansion, no evaluation was done of how costs might be different today if that had not been expanded at that time?

A. Ms. Cralle Jones, as I just said, for every one of our operations at every one of our plants, we made decisions based upon the information that was known at the time that those decisions were made.

Q. Yesterday when you were talking with Ms. Townsend regarding the CAM report for Mayo, which identified exceedances of several contaminants -- I believe, boron, chloride, cobalt, and TDS were some of them -- I believe you testified that there were no exceedance beyond the compliance boundary; is that correct?

A. Yes. And I'm glad you brought those up, because I looked at those a little more in depth last night. And the constituents that were brought up and named in all the CAM reports for all the basins, those were not necessarily chemicals or constituents that were beyond the compliance boundary, or show the trend, or show the plume where there was a concern; they would have been -- in some cases, some of those constituents in all the CAM audits were -- may have been one hit -- may have been a background wells.

So it's good to look at them across the board and really understand, instead of just listing out constituents where they're at in the environment and look across the entire site.

But for Mayo specifically, as I mentioned yesterday, the DEQ April 1st order to excavate did say that we have constituents beyond the compliance boundary, but we did not. And that was one of the things that we included in our appeal to the Office of Administrative Hearing.

Q. So is it the Company's position that there were never any groundwater exceedances beyond the Mayo compliance boundary?

A. Mr. Wells would probably be a better person to ask about the history of our groundwater activities at all of our sites. What I do know is that we do not have any impacts beyond the compliance boundary at Mayo, and we are not -- we are not required to implement any type of groundwater corrective action at

Mayo because of that fact.

Q. Okay. And that's as to groundwater.

Is it the Company's position that there were never any unpermitted impacts to Crutchfield Branch?

A. I think that would be a better question for Mr. Wells. He, again, has the history of our groundwater compliance, or our compliance at those areas. I do know at Crutchfield Branch, we did sample Crutchfield Branch -- excuse me, Crutchfield Branch as part of our NPDES outfalls, and there was surface water samples that were taken in other areas. And Mr. Wells may be able to go into a lot of more detail on that.

Q. Okay. All right. I have no further questions. Thank you.

COMMISSIONER CLODFELTER: Thank you. I do not have in my notes that any other party has requested to reserve right of cross examination on Ms. Bednarcik, but for the sake of being sure about that, let me ask.

Are there any other intervenors that have questions for Ms. Bednarcik on cross examination?

(No response.)

COMMISSIONER CLODFELTER: All right.

Hearing none, Mr. Marzo, any redirect?

MR. MARZO: Yes, Commissioner Clodfelter.

REDIRECT EXAMINATION BY MR. MARZO:

Q. Just starting off probably with Ms. Cralle Jones's last question, but you were also asked similar questions related to CAM studies by Ms. Townsend on cross yesterday. And you accepted a number of the information subject to check at that time, and I think you mentioned a moment ago, Ms. Bednarcik, that you had some time last night, I know it's very limited time, to look back at some of those reports. I know Sutton was one of those reports.

Is there any additional information you want to provide the Commission related to what you were able to review?

A. Yes. Specifically for Sutton, the CAM report mentioned constituents such as chrome 6 and chromium were two. Those were actually in background wells off site, and that later on the DEQ determined that those were naturally occurring constituents in the PD area and not impacted by any operations of Sutton. Also, that really, in our groundwater corrective action program, were only carried forward boron, arsenic, and selenium as part of the groundwater corrective action. So all those other constituents were either anomalies, one-time hits.

That's why I mentioned you really need to look at not just listing out constituents, but looking at where those impacts were. Were they in background wells, side gradients? Were they one-time exceedance but not a sign of a trend? So you really need to put things into context.

Q. Thank you, Ms. Bednarcik. Now, you were also asked by Ms. Townsend a series of questions about, I believe it's Hart Exhibit 67, that dealt with the lay of the land area at Sutton. And in particular, the Company's interaction with the interactive hazardous waste division; do you recall those?

A. Yes, I recall that conversation.

Q. Now, is there anything remarkable about the series of correspondence that Ms. Townsend asked you about?

A. No. So again, I've been working on remediation for many years and have had lots of interactions with regulatory agencies. North Carolina, South Carolina, other states with USEPA. What I saw in those documents is normal, is that you work back and forth with the regulator on what the next steps are going to be. If you need to do additional investigations of soil, groundwater, it's an iterative process working back and forth with the EPA, with the state EPAs, with our state regulators.

So when I read through those documents, I really looked at them and said, well, this is normal. This is how we interact with the agencies going back in order to make sure that whatever is the final remedy that goes in is an appropriate one. One that's approved that we feel comfortable with moving forward with, having that certainty to move forward with, that we're within the regulations. So that -- when I read through those documents, I really looked and said, yeah, this shows how we work with our agencies.

Q. Thank you, Ms. Bednarcik. Now, you were also asked some questions by Ms. Townsend regarding, I believe it's Hart Exhibit 68, which is the Department of Environmental and Natural Resources' initial findings and decision assessment of civil penalties related to Sutton; do you recall that?

A. I do.

Q. Okay. And Ms. Townsend chose to question you about the initial penalty assessment, which was issued in March of 2015. But that assessment doesn't tell the whole story; does it, Ms. Bednarcik?

A. It does not. When DEQ in this -- sent in that assessment and penalties, that was in direct violation of a 2011 policy document that DEQ had. So that is why the Company did contest that NOV, went to the Office of Administrative Hearing in order to contest it. We were prepared to fully litigate it, because we were following the guidelines that had been given to us by DEQ relating to groundwater. And the issuance of that NOV was in contrast to those guidelines that we were working under with the state.

Q. In regards to those guidelines that you just mentioned, do you have Hart Exhibit 12 available to you from DEP?

A. Give me one moment, please.

Q. Sure.

MR. MARZO: And while Ms. Bednarcik is looking for that, Chair -- Commissioner Clodfelter, for the record, this is the June 17, 2011, letter from NCDENR titled "Policy for compliance of long-term permitted facilities with no prior groundwater monitoring requirements," and I would ask that it be marked as DEP Bednarcik Redirect

Exhibit Number 1.

COMMISSIONER CLODFELTER: Okay. It will be so marked as Bednarcik DEP Redirect Exhibit Number 1.

MR. MARZO: Thank you, Commissioner Clodfelter.

(Bednarcik DEP Redirect Exhibit Number 1 was marked for identification.)

Q. And you just let me know when you're able to find that, Ms. Bednarcik.

A. I have it in front of me now.

Q. Now, does this letter describe the policy that DEQ had in place?

A. Yes, it does.

Q. And can you tell me your understanding of that policy, as laid out in this letter and the flow chart that's attached to this letter?

A. So the policy, in general, what it lays out and it shows really well in this flow chart, it starts off with use sampling to determine its groundwater quality in established compliance boundary. And if the groundwater concentration is greater than 2L, and it has been reported to the division, results are greater than naturally occurring concentrations, it really just shows that, if we are reporting to the agency and working with the agencies in order to address the impacts, then a fine or a penalty may not be necessary.

Actually, the last full paragraph on the previous page talks about that. It states that:

"However, as long as the permittee is cooperating with the division and taking all necessary steps to bring the facility into compliance, a notice of violation may not be necessary. The overall determination of whether or not a notice of violation is necessary will largely be based on the overall compliance history of the facility and the potential for impacts to human health and the environment."

So we were working underneath this policy, which is why when we received that NOV on Sutton, we were fully prepared to litigate it, because we were working under this guidance document with the agencies in order to address the groundwater.

Q. Now, you mentioned you were prepared to litigate it, but did the -- did that ultimately result in a settlement agreement in 2015?

A. Yes, it did. And what I just described about the 2011 policy and the fact that we were working under it is one of the reasons why we ended up; A, going into litigation, extensive discovery, and -- well, I said going into litigation, but we appealed it to the Office of Administrative Hearing, went into the extensive discovery, and it came clear that, yes, the Company was working underneath this policy, and it was a policy that was in effect at the time that the NOV was issued.

Q. And just for clarity, could you please refer to Duke Energy Progress' Cross Exhibit Number 20.

MR. MARZO: And for the record, Commissioner Clodfelter, this is the September 2015 settlement agreement between DEP and DEQ. I would ask to also that this be marked as Bednarcik DEP Redirect Exhibit Number 2.

COMMISSIONER CLODFELTER: It will be so marked.

MR. MARZO: Thank you, sir.

(Bednarcik DEP Redirect Exhibit Number 2 was marked for identification.)

MR. MEHTA: Chair -- Commissioner Clodfelter, this is Kiran Mehta, and I hate to interrupt the examination of my colleague, but yesterday we were calling exhibits that were referenced -- that are being referenced in

Ms. Bednarcik's direct testimony, Bednarcik Direct Cross Or Redirect.

COMMISSIONER CLODFELTER: That is correct.

MR. MEHTA: Would you -- would we be remiss in trying to number these exhibits in the same way? So this one would be Bednarcik Direct DEP Redirect Exhibit 2, and the previous one would be Bednarcik Direct DEP Redirect Exhibit Number 1.

COMMISSIONER CLODFELTER: Mr. Mehta, I'm going to put you on as an assistant to the Commission here. You are correct. Ms. Bednarcik will appear later in rebuttal, so we need to be able to differentiate redirect exhibits in her direct testimony from redirect exhibits in her rebuttal testimony, and I'm sure Mr. Marzo will agree with you. And so both his prior Exhibit Number 1 and this exhibit will be prefaced prior to the number as Bednarcik Direct DEP Redirect Exhibit Number 1 and Number 2.

(Bednarcik DEP Redirect Exhibit Numbers 1 and 2 were remarked as Bednarcik Direct DEP Redirect Exhibit Numbers 1 and 2.)

MR. MEHTA: Thank you, Commissioner Clodfelter. And just to paraphrase General Sherman, if somebody's going to give me that job; i.e., staff to make sure the exhibits are right, if nominated, I will not run; if elected, I will not serve.

COMMISSIONER CLODFELTER: Mr. Mehta, I should have added that it's a nonpaying job in any event. Let's understand it's a nonpaying job in any event.

MR. MEHTA: Thank you, sir.

COMMISSIONER CLODFELTER: All right. Mr. Marzo, with that bit of levity from your colleague, are you ready to proceed?

MR. MARZO: I am, Commissioner Clodfelter, thank you. And I appreciate that correction.

Q. Have you reviewed this document previously, Ms. Bednarcik?

A. Yes.

Q. And we've been discussing Sutton. But looking at page 1 of the settlement, it covers more facilities than just Sutton; is that -- is that accurate?

A. Yes. It covers all of the plant properties that have coal ash basins that are being addressed in North Carolina, so both for Duke Energy Carolinas and Duke Energy Progress, each and every one of those plants.

Q. So when Ms. Townsend referred to the $7 million amount that was agreed to in the settlement, that agreement included all current, prior, and future claims related to all of these facilities; is that a correct understanding of it?

A. Yes.

Q. Okay. Now, when I look at page 4 of the settlement agreement, does it specifically acknowledge the 2011 policy we were discussing previously?

A. Yes, it does. And that "whereas" where it talked about the 2011 policy was a current policy that was in effect, and that the 2011 policy applies to each one of the facilities that had been listed in it. Again, all the facilities in North Carolina.

Q. And does the settlement agreement's reliance on the 2011 DEQ policy acknowledge the Company's longstanding effort to work with the environmental regulator?

A. Yes, it does.

Q. Did the settlement allow the Company to implement CAMA more efficiently, from a regulatory perspective?

A. Yes, it does. It added clarity, understanding that we would -- both the Company and DEQ would be able to execute the groundwater work underneath the requirements of CAMA. And Mr. Wells can talk a lot more about groundwater, but that is included in this settlement agreement.

Q. Thank you. Now, Ms. Townsend referred you to Hart Exhibit 40 as well, which I believe is AGO's Exhibit 16 in this case. That document was titled "Ash basin closure strategy" developed I think in the 2013 time frame; do you recall those questions?

A. Yes. If I recall, that was a Duke Energy document, yes.

Q. Okay. And I believe you were asked some questions about the Company's evaluation of closure options at Weatherspoon in that time frame; do you recall that?

A. Yes, I do.

Q. And on page 2 of the document, in referring to Weatherspoon, it states that this design will be submitted to NCDENR in May 2013 expecting final approval in July of 2013.

Was final approval ever received?

A. No, it was not. So during that time period, DEQ also tried to finalize their guidance or their policy related to ash basin closure. So I mentioned yesterday that we were also waiting for the federal CCR rule to come out. DEQ was still grappling with what their closure policy would look like during that time period as well.

Q. And in that regard, can you tell me why it's important to have the full buy-in of the regulator before moving forward with the closure strategy?

A. It's important because what you don't want to do is to choose a closure strategy and move forward with executing that work without the buy-in because then that the agency may come back and say no, that's not what we want you to do, we want you to do something else. And those costs that would have been executed, or those costs that would have been gone to execute that work that hadn't been approved by the agency, some -- including some probably as part of this hearing, would have said that that was imprudent to do.

So we want to make sure that in order for us to initiate work and that moves forward in a way that is prudent, that we have buy-in from our regulators, especially on things that the regulators have direct oversight on.

Q. And did DEP try to get certainty from its state regulators around closure?

A. Yes. So we were working with the state regulators asking them questions. I believe I mentioned that in my discussion with Ms. Townsend, that we had discussions with DEQ using the Weatherspoon as kind of our template going forward. And so we were asking them questions as to what do we need to do, where do we need to go, so we were not working a vacuum.

Q. Are you familiar with witness Jim wells' rebuttal Exhibit Number 4 in this case?

A. Yes. But if you give me a moment, I'll open it up.

MR. MARZO: And for the record, Commissioner Clodfelter, this is the Progress Energy memo titled "Progress Energy, Duke Energy, and DENR meeting on July 2009." Would I would mark it for purposes of my redirect examination here as -- I believe we said it's Bednarcik Direct --

COMMISSIONER CLODFELTER: DEP Redirect

Examination Exhibit Number 3.

MR. MARZO: Thank you, sir, I'm trying to not get in trouble with Mr. Mehta.

COMMISSIONER CLODFELTER: It will be so marked.

MR. MARZO: Thank you.

(Bednarcik Direct DEP Redirect Exhibit Number 3 was marked for identification.)

THE WITNESS: I now have Wells' Exhibit Number 4 in front of me.

Q. Okay. So on page 2 of the memo, there is a paragraph number 3. And it's titled, "How does DEQ plan to address inactive sites that are not permitted and not operating: Give over to DWM, leave alone, monitor, and if sites are permitted and receiving waste, what are the closure requirements?"

Do you see that?

A. Yes, that's certainly what question number 3 asks.

Q. Now, would you read the second paragraph? And I want to ask you some questions about that.

A. "DEQ had on-site lagoon closure requirements, but admit they are light on specifics and open to a wide interpretation. These interpretations would be made by the appropriate regions on site-by-site basis. Both APS," which is the aquifer protection system -- section, aquifer protection section underneath DEQ. "So both APS and NPDES said they would get together internally to discuss closure requirements for ash ponds. They did not state by when they would issue closure requirements for ash ponds."

Q. Now, does this memo represent the fact that Duke Energy Progress was seeking guidance from its state regulator in this time frame?

A. Yes.

Q. And did Duke Energy Progress continue to try to work with the regulator to gain certainty around what closures would be permitted and what the requirements would be?

A. Yes, they did.

Q. Okay. And can I refer you to Duke Energy Progress Exhibit 8? It's amongst the potential cross exhibits.

MR. MARZO: And for the record, Chairman Clod- -- Commissioner Clodfelter, this is the March 26, 2013, email from Debra Watts with NCDENR to Mr. Stowe Allen (phonetic spelling) titled "Ash pond closure draft," and I would like to have that marked as Bednarcik Direct DEP Redirect 4; is that the right --

COMMISSIONER CLODFELTER: That would be correct, and it will be so marked.

MR. MARZO: Thank you, sir.

(Bednarcik Direct DEP Redirect Exhibit Number 4 was marked for identification.)

THE WITNESS: Mr. Marzo, I have that in front of me now.

Q. Now, are you familiar with this document?

A. Yes, I am.

Q. Now, does this email attachment refer to a draft ash pond closure plan requirement being developed by NCDENR?

A. Yes.

Q. And does the email indicate the Company provided comments and inputs to NCDENR on the closure guidelines that are presented in this draft?

A. Yes, it does. And it is in the 2013 period, so that shows that 29 -- 2009 memo that we just discussed, the 2013, it's not a -- it wasn't a simple process. It has taken a long time just between those two for DEQ to provide a draft guidance for our comments on.

Q. And were these guidelines, were they ever finalized, Ms. Bednarcik?
A. No, they were not.
Q. Now, have you reviewed Mr. Bonaparte's reports submitted with his testimony in this case?
A. Yes.
Q. And I won't mark this, but can you -- do you have that with you?
A. Yes, I do.
Q. Would you mind turning to page 5 of that report, which is titled "Section 3 results of review." And in that portion of the report, Mr. Bonaparte gives an overview of the basins that he reviewed from Georgia, North Carolina, South Carolina, and Virginia. And you let me know when you get -- do you have that?
A. I do. And it's Exhibit 2 to Mr. Bonaparte's rebuttal testimony.
Q. Okay. Now, he identifies only three impoundments out of the 93 that he reviewed as having any sort of historical closure planning; is that -- am I reading that correctly?
A. Yes. And he has a footnote in there that says historical in this contact refers to the time frame 2009 to 2011 or earlier.

Q. Is that consistent with where you understood the industry to be in terms of any sort of closure planning that -- during that time period?

A. Yes.

Q. And can you tell me your opinion as to whether it would be reasonable to proceed with the closure strategy while your regulator is still trying to determine the rules and requirements for closure?

A. It would not be prudent. As I mentioned earlier, having that certainty, having that clarity as to what we would need to do to have approval for closure ends up taking away any -- anything that we might have executed on that had to be redone or taken back. So having that clarity makes sure that we are executing the work per our rules and regulations.

Q. Now, I just want to ask you a few questions related to some of the cross you received on the CAM reports.

And similar to DEC case, Ms. Townsend asked you a number of questions flipping between the various CAM audits that were included in Mr. Hart's testimony and exhibits from the past case and this case, but the period covered was 2018 and 2019 for the DEP coal plants; do you recall those?

A. Yes.

Q. And did the information that Ms. Townsend read to you from these reports constitute new findings?

A. No, they did not. Very similar to what I testified in the DEC case, that the findings that they had listed in the 2018 CAM audit reports were the same findings that they had in previous years' CAM audit reports related to groundwater. And in all of those, what the Company's response, and it's also in those audit reports, that the Company was -- had -- was working with DEQ and -- in order to determine how to address those impacts.

So it wasn't anything -- it wasn't a new finding. It was a restatement of previous findings that, yes, we did have groundwater exceedances of the 2L standards, and that, yes, we were working the state. That was the extent of the finding.

Q. So would it be fair to classify those as legacy issues?

A. Yes. That's exactly how -- when we were looking at them, evaluating them, they were not new issues. They were not based upon the current operations of the plants, they were legacy issues.

Q. And just for clarity, where does the data

come from that the CAM uses in these reports?
A. The data was from -- was, of course, provided by Duke Energy to the CAM auditors. Same data that's provided to the state regulators.
Q. Okay. And you discuss this a little bit, but I just want to make sure this is clear now.
Ms. Townsend asked you some questions with the CAM reports related to various location restrictions for the surface impoundments. For example, there were several subjects to check.
I think one of the ones that she actually referred you to a page was with H.F. Lee facility, and she asked you whether it met the surface impoundment standards for placement above the uppermost aquifer and whether it met surface impoundment standards for wetlands; do you recall that?
A. I do.
Q. Okay. Is the location restriction for placement above the uppermost aquifer a requirement in the CCR rule?
A. It is specifically called out in the 2015 final CCR rule.
Q. Now, is that a new requirement with the CCR rule? Is that -- the CCR rule is new. Is that a new

requirement?

A. Sorry, having issues with my spacebar again. Yes, it was a requirement -- a new requirement under the CCR rule.

Q. And is the location restriction for wetlands part of the CCR rule as well?

A. Yes.

Q. And is that also a new requirement with the CCR rule?

A. Yes. Those requirements were, again, to initiate, to trigger closure under the CCR rule. That was how the CCR rule -- that the federal CCR rule did the evaluation to say whether or not closure needed to be triggered of those basins.

Q. And when did that rule go into effect?

A. It was in 2015. I can't remember the exact date. But that's why we refer to it as the 2015 rule. But it was sometime in the middle of the year of 2015.

Q. Now, with that in mind, when the Company's various ash impoundments were first developed, were they lawfully permitted at the time they were built?

A. Yes, they were.

Q. Okay. And have they been subject to permit renewals over time?

A. Yes.

Q. And with the passage of the CCR rule and CAMA, is the Company similarly complying with the rules and regulations in effect at this time?

A. Yes. New change, new rule, new regulations. We have to comply with the new rules and regulations, and that is what we are doing.

Q. Now, in your expert opinion, does the fact that an impoundment may not meet the criteria of a newly created location or restriction standard say anything relevant about the historical prudent or reasonable operation of that impoundment?

A. No, it does not.

Q. And are there CCR surface impoundments in other jurisdictions that don't meet newly created restrictions like the location restrictions established in the CCR rule?

A. Yes. This is something that all the utilities across the nation are doing evaluations on, and there are numerous impoundments that do not meet those location restrictions.

Q. And is it your understanding, at least from your peers, that those other utilities are also taking the steps necessary to comply?

A. Yes. So I'm part of a peer group of a number of utilities, and based upon discussions with them, they are complying by the CCR rule and having to move forward with closure.

Q. Now, you got a number of questions about groundwater exceedances and seeps yesterday.

And to begin with, is Mr. Wells testifying later in this case and can further address any open questions regarding groundwater exceedances and seeps, should parties choose to ask him?

A. Yes. He actually covers groundwater and seeps in his rebuttal testimony, and he also did it in the 2017 case. He is well knowledgeable on groundwater and seeps.

Q. And have you reviewed Mr. Wells' testimony in this case?

A. I have.

Q. I'm going to ask you a question regarding his testimony. In his testimony, he states that:

"Impacts to groundwater around basins are not the result of mismanagement. The existence of groundwater exceedances at or beyond the compliance boundaries at these sites is a function of where these sites are on the timeline of groundwater assessment and corrective action under the modern laws that have changed that the way that the unlined basins are viewed. As these views have changed, the Company taken every action required by it DEQ and DHEC to address groundwater impacts as they've been identified?"

Is your view consistent with Mr. Wells' understanding as I just indicated?

A. Yes. As you just indicated, my view is consistent with what is in his testimony.

Q. Similarly, did you review the portion of Mr. Wells' testimony where he explains that DEQ did not consider seeps to be a priority for NPDES permitting?

A. Yes. I'm going off of memory. I believe he ends up quoting a document from DEQ where a -- one of the regulators said that it was not considered a priority.

Q. Are you referring to the deposition of Sergei Chernikov that's referred to in his testimony on page 58?

A. Yes.

Q. Okay. And what is your understanding of when seeps became more of a priority for the environmental regulator?

A. So Mr. Wells can confirm on this, because again, he has the history of seeps way more than I do. But I believe it was in the 2010 time period. I'm going off of memory. And when EPA made that and said we need to start looking at seeps, the Company went to DEQ in order to determine what are the steps that we need to take in order to address this.

Q. And did it take time for DEQ to develop and implement a strategy to accommodate seeps into the NPDES water permits?

A. Yes, it did. And that's actually how we came up with our special orders of consent. Those incorporated the seeps at our plants.

Q. And I think you said this, but I just want to be clear. The Company has worked with DEQ throughout this whole process; is that right?

A. Yes.

Q. Now, you also were asked some questions about the ratings of certain basins.

Do you remember Ms. Townsend asking you about the Asheville 1964 surface impoundment and the Cape Fear getting a poor rating from EPA inspections after the TVA spill?

A. Yes, I do remember that.

Q. Now, would you mind turning to DEP Redirect

Exhibit Number 62?

A. (Witness peruses document.)

MR. MARZO: And this is the -- Commissioner Clodfelter, this is the final CCR rule, page 213115 [sic] of the preamble, and I'm going to ask some questions to Ms. Bednarcik about it. I may just go ahead and mark this just for the purposes of the record. I would like --

COMMISSIONER CLODFELTER: It's, strictly speaking, not necessary. We do take judicial notice of statutes and rules, but if you wish to mark it for purposes of later reference, we'll do that.

MR. MARZO: In light of that, Commissioner Clodfelter, just to be safe for purposes of not having Mr. Mehta scream at me, I will -- I'll go ahead and mark that.

COMMISSIONER CLODFELTER: We'll do it however you wish.

MR. MARZO: If we could mark it Bednarcik Direct DEP Redirect Exhibit --

COMMISSIONER CLODFELTER: 5.

MR. MARZO: -- 5. That's right. Thank you.

COMMISSIONER CLODFELTER: It will be so marked.

(Bednarcik Direct DEP Redirect Exhibit Number 5 was marked for identification.)

Q. Do you have that document, Ms. Bednarcik?

A. I do, but I can't remember what page.

Q. It's page 21315.

A. (Witness peruses document.)

I found it.

Q. Okay. And it's discussing -- if you would, there's a first column -- there's several -- there are three columns, and it's the first column. And in that first column it's discussing the EPA's inspection of surface impoundments across the country after the TVA spill; do you see that, first full paragraph?

A. Yes, I see that.

Q. Now, how many surface impoundments across the country received a poor rating in accordance with this first paragraph?

A. At the end of that first full paragraph, it says out of the 559 impoundments assessed, 152 received a poor Commission rating. But then it goes on to say that it's important to note that the condition ratings do not necessary imply that the unit had inadequate structural integrity.

Q. Okay. Could a surface impoundment get a poor rating for a reason related to documentation?

A. Yes. And I believe that next paragraph lays that out as one of the items. So if they did not have all the documentation available to them when they did an evaluation, that was one of the reasons why a basin may have received a poor rating.

Q. So in looking at this paragraph, is it your view or your reading of this paragraph that EPA stated that the condition rating did not necessarily imply that the unit had inadequate structural integrity?

A. Yes, that is what it states.

Q. Do you know if Progress committed to getting that documentation to EPA?

A. Yes, I believe that they did.

Q. And are there a number of Progress surface impoundments that received fair and satisfactory ratings?

A. Yes, there were.

Q. Okay. Do you remember when Ms. Townsend asked you about Cape Fear surface impoundments being designated as significant hazard by EPA inspection in 2019?

A. Yes.

Q. Does the final CCR rule define significant hazard?

A. Yes, it does.

Q. And does the hazard classification under the CCR rule and the EPA inspections have anything to do with the structural stability or integrity of a surface impoundment, itself?

A. No, it doesn't. What it discusses is what that potential harm would be if there was a breach of the dam. So it looks at -- in some of our documents now we call them inundation studies. It's to evaluate if something were to happen to that dam, who would it affect, how many people, and how much of an area. And that is one of the ways that they did the hazard clarification. Is if a catastrophic failure were to happen, what the results would be.

Q. Thank you, Ms. Bednarcik.

MR. MARZO: Commissioner Clodfelter, that's all the redirect I have right now.

COMMISSIONER CLODFELTER: Thank you, Mr. Marzo. Let's see if Commissioners have questions.

Commissioner Brown-Bland?

COMMISSIONER BROWN-BLAND: Yes, just a couple here.

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q. Ms. Bednarcik, a few minutes ago you were discussing with Mr. Marzo I think what he had marked as Bednarcik Direct DEP Redirect Exhibit 1. I'll have Mr. Mehta correct me in a minute, but I think that's the one. It was originally Hart 12, I believe. And in that, you had a discussion about whether -- let me see if I can find it. Here we go. Whether the NOV -- when an NOV is issued -- or it was about the Company being able to work with the regulator, and work cooperatively, and sometimes that would mean that the notice of violation may not be necessary.

Do you recall that question and answer session?

A. Yes, ma'am.

Q. And so I just wanted to follow up a little bit to ask, in your experience, it's not unusual for a regulator to work with the regulated organization to correct an environmental issue or to try to head off an anticipated violation; is that right?

A. Yes. So -- and that's how Duke Energy has been working with our regulators in North Carolina cooperatively in order to make sure that we move forward appropriately. To head off items, to correct items that are addressed.

Q. So is it also your experience that, during that whole time when you're working together with the regulator, the Company is working hard to avoid the outcome of having the regulator issue the NOV; isn't that correct?

A. Yes. That's one of the reasons that we work with the regulator in a cooperative way, is to -- is to not receive a notice of violation.

Q. So working together is not a promise, though, that the NOV won't ever issue; isn't that also true?

A. Yes. And that's why in that document it says that it may not be necessary. It didn't say will not be necessary. So depending upon the working relationship and if things are moving towards a good corrective action.

Q. And so if the regulator is ultimately not satisfied with the efforts, even if those efforts -- everybody's working together well and those are the efforts that the regulator approved, if somehow the regulator is not satisfied with either the efforts or the results of the efforts, the NOV could issue at any time; is that not true?

A. Yes, that is true. But one of the reasons that we did go to the Office of Administrative Hearing on that specific one is because we were working with the regulators and moving appropriately through the process with them.

Q. All right. But the regulator's always within its rights, if it's not getting the results it wants for whatever reasons, it could protect, and preserve, and reserve, and all those kinds of things, and it could be a reason for it to issue the NOV in spite of the cooperative working relationship; isn't that correct?

A. Yes.

Q. All right. And then my last -- let's see.

Do you know whether seeps that were unpermitted discharges -- whether the seeps were unpermitted discharges in violation of the NPDES permits when you were having that discussion a minute ago?

A. Commissioner Brown-Bland, that's a much better question for Mr. Wells. He has the histories of the seeps and the SOCs. I do know that the SOCs are a mechanism that the agency has when there is some uncertainty in -- and I'm going off of memory here, uncertainty of rules and regulations in order to address those and be able to move forward with them.

But Mr. Wells would be able to answer that question in much more detail than I could. That's about my knowledge of the seeps.

Q. Okay. So you don't know if the discharges that were in violation were unpermitted?

A. It would be a better question for Mr. Wells. I'm sorry.

Q. All right. And then, finally, this is similar to what I asked last time in the DEC case.

But in the last DEP rate case, witness Kerin provided, as part of his direct testimony, an exhibit, in that case it was Kerin Direct Exhibit Number 5, that showed the cumulative quantities of the CCR sluice to each DEP basin through January 2017. I think it was January 17, 2017.

Could you prepare a late-filed exhibit in this DEP docket updating Kerin Direct Exhibit 5 to show the cumulative quantities of CCRs for each basin through 2019?

A. Sorry. Again, having issues with my spacebar. Yes, ma'am, of course we will.

Q. All right.

COMMISSIONER CLODFELTER: Commissioner Brown-Bland, I want to be sure we get your request clear. Are you asking for the cumulative total amounts sluiced to the basin through that date? Are you asking for a net amount? Because there will -- in several of the basins have been excavations and removals in the period after 2017. So I think just so we don't have to go back to the Company a second time, you might want to say which way you want it. Or maybe you want it both ways, I don't know.

COMMISSIONER BROWN-BLAND: If the witness can provide it both ways, that would be good. But what I was specifically asking is an update to what went into Kerin Direct Exhibit Number 5. And I was just going to say to you that I do request that as a late-filed exhibit.

COMMISSIONER CLODFELTER: Okay. The Company's got the request?

COMMISSIONER BROWN-BLAND: All right.

MR. MARZO: Yes, Commissioner Clodfelter, we have it.

Q. And one more question for you, Ms. Bednarcik, going back a little bit.

Do you -- do you know whether the Company had to admit violations in order to get the SOC, or that's part of the consent?

A. I do not recall off the top of my head. I would have to look at the language in the SOCs, themselves.

Q. All right. Is that something that witness Wells will know as well?

A. Yes, he would.

Q. All right. No questions -- further questions at this time. Thank you.

COMMISSIONER CLODFELTER: Thank you. Commissioner Gray?

COMMISSIONER GRAY: No questions at this time.

COMMISSIONER CLODFELTER: Thank you. Chair Mitchell?

CHAIR MITCHELL: No questions.

COMMISSIONER CLODFELTER: Okay. Thank you. Commissioner Duffley? You are on mute, Commissioner.

COMMISSIONER DUFFLEY: Okay. My spacebar doesn't work. I have no questions.

COMMISSIONER CLODFELTER: Commissioner Hughes?

COMMISSIONER HUGHES: No questions for me.

COMMISSIONER CLODFELTER: All right. Commissioner McKissick?

COMMISSIONER McKISSICK: No questions, Mr. Chair.

COMMISSIONER CLODFELTER: All right.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Ms. Bednarcik, I have a few. And because I've been trying to keep up with you guys, I may be a little bit disorganized in the sequence of the questions, so try to bear with me, if you will.

In February of this year, the Company advised the Commission that the Neuse River had overtopped the dikes at the H.F. Lee plant and had -- the river had flooded several of the older ash ponds. Are you familiar with that incident?

A. Yes, I'm aware of that incident.

Q. And as I understand it, the Company also later reported to us that there had been no breach of those dams or any structural damage to the dams. My question to you really is, is that the first instance in which that had occurred?

A. Commissioner Clodfelter --

Q. At the H.F. Lee plant.

A. So I don't know if that was the first instance where there was a flooding of the Neuse River. I do know that those dams were reclassified by the dam safety organization. So we had to prepare emergency action plans for those that had triggering events and things that we would have to report out and be able to address it appropriately. So those EAPs, emergency action plans, and the reclassification happened last year. But related to prior flooding, I would have to go back through the notes and look.

Q. Is there someplace where that information has been captured and we could access it?

A. I would have to check with the site engineers and see if that's available. But I don't know off the top of my head, but that is something -- I do know that the Neuse River has flooded, but specifically related to what has happened at those basins, I'm not sure.

Q. And so if you were able to determine that by consulting with the plant records, would those records also show what actions, if any, were taken at the time in response to a potential -- an actual flooding event that may have occurred; it would show that?

A. I'm not sure. I would have to look and see what records we have available on that, if we do have records.

Q. All right. I will ask for purposes of completeness, do you know if there have been similar flooding events at, for example, the Sutton plant, or at the Cape Fear plant, or any of the other plants?

A. I do know that we did have a flooding at Sutton as part of one of the hurricanes, and we had actions that we took related to those hurricanes. And there are some other times where we have entered into those emergency action notifications due to hurricanes and flooding events. Specifically when and what locations, I can't recall what they are.

Q. I think what I'm really interested in finding out is really the historical record about any potential -- any actual flooding events that occurred with respect to the ash ponds at the Company's plants, and what actions were taken in response to those flooding events. Only because we had one this year at the Lee plant does that question really come to mind, but I think it's a pertinent question to know the historical record on that.

Perhaps you and your counsel can talk some about that, and if you're able to talk to me further about that on your rebuttal testimony, I may ask you about it again. At this point, I won't frame a late-filed exhibit question because you may be able to talk to me and give me better answers, more complete answers -- not that your answers are wrong, but more complete answers on rebuttal. So we'll leave that point for the present. Okay?

I need to ask -- I need to ask you a couple of questions about the Sutton plant. In the present case, the deferred costs for which the Company is seeking recovery, are any of those costs include any excavation, off-site transportation, and off-site disposal of any of the ash at Sutton? To state the question another way, was all of that off-site disposal completed before the costs were accumulated that you're requesting recovery in this case?

A. I would have to go back and confirm this, but my understanding, as I sit here today, it's all for ash that we ended up putting inside of the on-site landfill. Similar to Dan River, there may have been in woody debris or areas that like that that we had to send off site that wasn't allowed to be placed on the on-site land fill, but I can confirm that.

Q. Okay. I would ask that you do check that, and we'll revisit that on your rebuttal testimony. Thank you.

In regard to the Sutton plant, are you familiar with the November 2004 analysis of the options for dealing with coal ash at the Sutton plant that was introduced into the record in the prior Duke Progress rate case?

A. Yes. If I remember correctly, that was the one that was authored by Mr. Bill Forester. Yes, I am aware of that.

Q. At least a copy I'm referencing was marked in that case as Wells Cross Examination Exhibit 3, but I don't remember which party presented it. But you're familiar with the report. I'm not going to ask you anything in the report, I'm really still trying to find out several things.

Do you know -- have you seen, or do you know if there exists, anything in the nature or character of a memorandum of decision, a record of decision, an action memorandum, minutes of a committee meeting, or anything of that sort that outline the decisions made in consequence of that report and the recommendations of that report?

A. I have not been able to locate a document that said this is specifically what came out of that report. I have had conversations with the author of that report and others who worked at the Sutton plant, and the decisions that were made as to what we ended up doing at the Sutton plant after that report.

Q. You have had conversations with the author of the report about the follow-up actions?

A. Yes, I have.

Q. What did you learn about the decision that was made?

A. What I learned was that we ended up not moving forward with the recommendations. There was changes we ended up -- part of that document was a forward-looking document of how much ash -- how much room do we need to handle the ash for a long-term operation of the plant. As you know, at the Sutton plant, ended up retiring, and going off of memory, 2012, 2013 time frame. So as we were moving forward and determining what do we need to do for space to make sure we have enough space at the plant, itself, there was some modifications that were made inside the basins where we were able to do vertical expansions and dry stack ash inside the basins, which was allowed underneath the permits at that time.

So we did not need to move forward with creating a new basin or creating an on-site landfill at that time because we had sufficient space doing dry stacking inside the basins to not execute, to have those capital costs at that time.

Q. Well, do I understand that part of the consideration was the anticipation that the plant would be retiring or converting perhaps to a different fuel? Was that part of the consideration at the time?

A. In the 2000 -- I believe that document was 2004.

Q. November 2004, yes.

A. Yes. So that was -- we always try and look many years in the future, because it takes quite a lot of time -- if you're going to do an on-site landfill, you have to do the site suitability studies and build the landfill first. So we're always looking out in the future. The Duke Energy Carolinas had those 10-year plans, kind of, looking at what we would need in 10 years to do forward-looking. Progress did the -- Duke Energy Progress did the same thing.

I do have available a document from 2006 where they were still evaluating the Sutton plant and whether or not operations needed to continue, what we would need to do for ash placement. Because we were -- if we were going to operate until 2025, what would happen; would we have enough room? So that evaluation continued.

The determination was we still had enough room inside the basin to manage the ash. That's why we didn't move forward with a landfill at that time or any other considerations. So it's an ongoing evaluation. I don't know the exact year that they determined to go to the combined cycle and the shutdown of the plant, but all of those decisions were all part of an evaluation of what do we need to do to make sure that we are maintaining operations.

Q. Thank you, Ms. Bednarcik. You referenced another document that you had access to from 2006 that further considered the options at the Sutton plant.

Is that available and could be produced as a late-filed exhibit?

A. Yes, it can.

COMMISSIONER CLODFELTER: Mr. Marzo, I would request that document as a late-filed exhibit.

MR. MARZO: Yes, Commissioner Clodfelter, we'll provide that.

COMMISSIONER CLODFELTER: Thank you.

Q. Ms. Bednarcik, I asked Mr. Kerin this question, and I commend you for your education research. You've dug into this, and so I'll ask you a question that Mr. Kerin didn't know the answer to at that time, maybe today you do know the answer.

Were there similar studies, like the November 2004 study that was done at Sutton -- were there similar studies done at the other Duke Progress plants at a time when the Company was considering what it needed to do going forward about management of the coal ash? Have you identified other similar studies to that study at Sutton?

A. Commissioner Clodfelter, unfortunately, I have not been able to identify documents similar to that one at Sutton, specifically. But again, discussions with people who had been in the Company during that time period, that document was put together for budget purposes to try and understand what do we need to do for budget, looking out in the future. So that is one of the things, of course, all of the plants would do to make sure that we can continue operations.

But we have not been able to locate documents -- specific documents like that one.

Q. Well, I appreciate your answer. I take your answer. Let me ask it again a little more specifically and just see if that changes in any way. I don't know that it will but let me ask.

I'm looking at, for example, the exhibits to your prefiled testimony, and just -- you don't need to have it in front of you. They say what they say. But, for example, you report the history of the Weatherspoon plant, for example, that the ash basin there was constructed in 1955, and it was expanded in 1963 and then again in 1979.

And would there not have been some kind of internal analysis of options at the time those expansions occurred -- or I should say prior to those expansions -- in order to consider what the best course of action was going forward? Would there not have been some kind of internal process?

A. So knowing how the Company operates today in order to make decisions as to what we're doing going forward, in order to make sure we continue operations of our plant, I would say that's a standard practice. Unfortunately, we haven't been able to locate those documents where those decisions and those decisions were made and how they were made.

I know that information on the -- how the basins changed over times, and we actually have on our public CCR website called the history of constructions. We pulled what we could find as to what the modifications were made, but those analyses as to why those decisions were, we haven't been able to find.

Q. And you have satisfied yourself that a diligent and thorough search has been made for such documents?

A. Yes.

Q. Okay. I need to ask you now some questions that -- I tried to piece together what we heard from Mr. Kerin three years ago and your testimony here, and then some of the other questions from the written documents. And it's on the question that Ms. Townsend talked to you about concerning the dewatering of the basins -- of the inactive basins -- of the inactive basins. And I refer you to -- do you have your prefiled direct testimony available?

A. Yes, I do.

Q. You might take a look at page 20. That's really where I want to start talking about the subject.

A. (Witness peruses document.)
I have that in front of me now.
Q. And there's a question that begins below the chart on that page. There's a chart at the top, and then the question begins on line 1. You're asked about the closure activities at Cape Fear and H.F. Lee after September 1, 2017, and on line 11, you say:
"To prepare the site for excavation, Duke Progress began the bulk dewatering of the Cape Fear and H.F. Lee impoundments after receipt of the revised NPDES discharge permits."
I need to understand when the dewatering began. Was it after September 1, 2017?
A. So the reference I made in my direct, for the most part, was for the active basins that still have water in them is when we started the bulk dewatering of those active basins, not the inactive basins. In a couple of those locations there may be small areas where there is standing water in the area, so, of course, we would have to get that water out before we move forward. But the bulk dewatering is with those active basins that did have a significant amount of head still on it and where we had not done --
Q. Well, check me on this -- check me on this.

I apologize to you, Ms. Bednarcik, and my memory may be completely wrong, but as of September 1, 2017, were Cape Fear and H.F. Lee still have -- operating coal units sluicing ash to the basins?

A. So you are correct, they did not; but we had what we called active basins at each one of those that still had a water -- amount of water on top of the basins. They were the basins that had been in operation when those plants had retired. So we had not removed all the water from those basins, and those basins are the ones that were referenced in my direct testimony.

Q. Okay. I think I understand now, and maybe it's an issue of our -- the use of the terms. To me, inactive -- I was using inactive to refer to a basin that was not receiving sluiced coal ash any longer. I was referring to that as an inactive basin.

I understand that you refer to an active basin as one that still contains standing water, fully saturated ash with standing water; is that correct?

A. Commissioner Clodfelter, I think you're right. It's the nomenclature we're using. So active basins -- Duke Energy, how we have all of the basins identified, typically the last one that was the active one, we call it the active basin. But you are absolutely correct, they were not receiving CCR units because those plants had been decommissioned and were no longer producing ash. But it was those last basins that still had the water in them. And that is a nomenclature issue. We refer to them as the active basins. But they were inactive because they were not receiving ash; you are correct.

Q. Well, at the Cape Fear plant, there were a number of basins. Let's take that as an example. There were a number of different ash ponds. And at the end of that plant -- coal -- that plant's life as a coal-fired generating facility, only one of those basins was actively receiving sluiced ash. And so when that plant that was decommissioned as a coal plant, I take it that you would call the last pond to receive ash still be an active basin.

Let me ask you, then, about the other ponds, the earlier ponds, the ones that stopped receiving ash at Cape Fear -- received no ash after the 1970s. I think there were either three or four at Cape Fear that didn't receive any ash after the 1970s. Those would not be active basins under your definition, would they?

A. Yes, that is correct.

Q. Okay. When did the dewatering -- bulk dewatering of those basins begin?

A. I don't have a date for bulk dewatering. I do know that the current state of those basins is that they are -- they have soil on top of them, for the most part have trees on them, and then revegetate them. But I do not have a date of active dewatering for those basins.

Q. Was it before September 1, 2017?

A. Yes.

Q. And are there any records that would show when that occurred?

A. I have not been able to identify any records of when that occurred.

Q. So -- and this is -- this is useful because, again, Mr. Kerin did not have access to some of the information that you've had access to, so I need to pursue this with you.

So in -- let me get the exhibit from your testimony about the Cape Fear plant. The last basin -- this is Exhibit 13 to your prefiled testimony. It's Exhibit 13, which is just a short summary of the site history of the Cape Fear steam station. It says that the last basin to receive ash was what you call the

1985 basin. And as I understand it, that one would be considered the active basin under your terminology. It was the last one to receive ash. It received it up until 2012.

The testimony in this case and in the prior case was that the 1956, 1963, 1970, and 1978 basins at Cape Fear did not receive any ash after 1970 -- after 1980; they stopped receiving ash after 1980.

Do you know when soil covers were placed over those basins?

A. Commissioner Clodfelter, I have not been able to locate documents that say specifically when they had soil covers over them.

Q. Have you talked to any site personnel who have recollection of that occurring?

A. The site personnel I did talk to also did not have recollection of when that occurred.

Q. Did it occur in the case of all of those basins? Were all of them dewatered, and soil cover, and vegetation placed over them when they no longer continued to receive waste ash?

A. I could talk about as they sit there today and when I visit them, they all have soil on covers over them and trees. Again, there may be pockets here and there of depressions where there is standing water. I'm trying to remember all the different basins and how they look. But I do not, especially when I visit them, I did not see bulk water in those basins.

Q. And if -- I want to be as efficient in the questioning as possible, but I don't want to push you into anything you don't want to go to. If I ask you the same questions about H.F. -- the H.F. Lee plant, the Weatherspoon plant, and the Robinson plant, and the question again would be: When was the bulk dewatering of the old basins that you don't call active basins, when did that occur? When was the soil cover put on? When was the vegetation established? Would your answers essentially be the same, at some unknown time in the past?

A. Yes, they would be the same.

Q. And would it also be true that every one of those basins at H.F. Lee, at Weatherspoon, at Robinson did, in fact, have at some point bulk dewatering, soil cover, and vegetation?

A. So I don't know if they would have had what we call bulk dewatering today, which is the pump inside of it to remove all the water. I do not know how the water was -- if it was removed through a pump or if it was removed through natural -- out through an NPDES. Of course, we -- if we have an NPS [sic] discharge in that area, if we as for retirement of an outfall, there would have been more water in those basins at that time. But how they were dewatered, I have not been able to find records of specifically how they were dewatered or when they were dewatered.

Q. Ms. Bednarcik, thank you. I may come back at this and revisit it a little bit more when you come on in rebuttal. But again, I want you to understand, my reasons for doing so is that, as far as Mr. Kerin was aware, and based upon the information available to him at the time, there had been no dewatering, no vegetative cover, and no soil cover, and no vegetation established at any of those basins at the time -- that he was aware of at the time he testified in 2017. So I need you to understand why I'm pursuing the line of questioning here. It's because this is important information and we need to develop it fully.

A. I understand, Commissioner Clodfelter, and I'm going off of -- I'm going off of -- I'm trying to visit every station in my mind of what it looks like in each one of the basins in order to make sure I answer appropriately of what it looks like today. But as I

mentioned earlier, we have not found historic records.
Q. I understand. Thank you. And as I say, I may revisit this with you on rebuttal, but that will give you a little bit more time to sharpen up your recollection on these things and see if you come up with anything else. I'm just trying to get a complete understanding of that.
Let me move to a different topic. Ms. Townsend was questioning you. She had asked some questions about corrective action issues where there were -- I'm trying to phrase this in a shorthand fashion. Corrective action issues in areas where there had been exceedances discovered beyond the compliance boundary, and I believe the Roxboro plant and the Sutton plan. Do you recall her questions on that topic?
A. Generally, yes.
Q. Okay. And if I recall correctly, the only two where you and Ms. Townsend talked about exceedances beyond the compliance boundary were at Roxboro and at Sutton; is my memory correct on that?
A. Yes. I believe those are the ones that we discussed.
Q. All right. Are there any other plants -- I

know you were asking about Mayo, so let's leave Mayo aside. I remember your answers on Mayo.

All of the other plants: Cape Fear, Weatherspoon, H.F. Lee, and Robinson, is there -- are there any exceedances, groundwater exceedances of the 2L standards beyond the compliance boundaries at those plants?

A. Commissioner Clodfelter, that's a much better question for Mr. Wells.

Q. I'll hold the question for Mr. Wells. Thank you. All right. Let's just stay for now, then, with Roxboro and Sutton.

So if you -- you're dealing with the exceedances there, you need to do an assessment, you need to do your sampling, you need to develop through working with the agency corrective action plan relative to those exceedances, and then after you and the agency agree on a corrective action plan, you implement the plan; have I got the basic steps correct there?

A. Yes.

Q. And with respect to those cases at Sutton and at Roxboro where you have a situation such as we just talked about -- exceedances beyond the compliance boundary that need to monitor and assess, develop a corrective action plan with the agency, and then implement whatever the agency says you should do -- in those cases, you would be undertaking those steps, would you not, whether or not you were closing the pond?

A. Yes. We would be working with the agencies on those whether or not closing the pond.

Q. You would be required to take those actions and incur the costs associated with those actions even if the plant were still operating as a coal plant, even if it were still sluicing ash to the impoundment, and there were no such things as CCR rule and CAMA; you would still be required to do those actions; would you not?

A. Yes.

Q. And so my question really is, are any of the costs for which the Company is seeking recovery in these case -- in this case, any of the costs associated with the Sutton plant or the Roxboro plant, are any of those costs include the activities associated with the exceedances beyond the compliance boundary? Monitoring, assessment, development of a corrective action plan, or implementation of a corrective action plan. Did I get my question clear?

A. I think so. I understand where you're going with this, Commissioner Clodfelter. So yes, it does include. Because with the passage of CAMA and the federal CCR rule, they ended up becoming a -- with those rules and with those regulations -- tied to the closure of the basins. So that is why the activities are being done related to groundwater impacts, are considered AROs.

And this may be a better discussion on accounting and how accounting put it together, with another witness whose name just went out of my head, but -- because as soon as those roles were passed and they included groundwater corrective action, they were tied to basin closure, that's why there are AROs and included in the costs today.

Q. Ms. Bednarcik, I thank you for your answer, and you do understand the point I'm trying to really understand here. I just noticed that I have taken advantage of our court reporter and gone past our normal morning break time. But I only have a couple more questions for you.

COMMISSIONER CLODFELTER: So we'll take a late morning break, Joann, if that's all right with you. All right.

Q. I'll try to finish up my questions for you and then we'll take a break at that point.

Ms. Bednarcik, I understand your answer. I would be interested, nonetheless, in seeing if I can get a cost breakout for the Sutton costs and the Roxboro costs of the portion of those costs that is associated with what I'll call, an umbrella term, corrective action beyond the compliance boundary. That's just an umbrella term that embraces the activities associated with monitoring, assessing, developing a corrective action plan, and implementing that plan beyond the compliance boundary. Is it possible for me to get a breakout of that?

A. I would have to talk to our accounting group. I do know, in my testimony, I had a breakdown; one of the items was groundwater. That does include groundwater associated with CAMA as to groundwater associated with CCR, but, of course, we -- those requirements have -- CAMA and CCR have lots of groundwater requirements in them, so I don't know if we will be able to pinpoint specific areas. Because once those came in, we moved forward with addressing them associated with that. So I don't know if we'll be able to pull it out, but I do know that's one of the reasons we had groundwater as a separate item in my testimony.

Q. I thought that was the case from the way the testimony was presented, but nonetheless, I'll leave that as a homework assignment between now and rebuttal time for you and Mr. Marzo, if that's okay. And I want to ask you one last couple of questions. And for this purpose, let's -- let's get you to page 17 of your prefiled direct testimony, please.

A. (Witness peruses document.)

I'm there.

Q. Okay. I want to look at the Table 1 at the top of the page. That's a summary of costs for which recovery is being sought in this case at the Mayo and the Roxboro plants. We had some discussion about this during the DEC case. And my apologies to you, I simply forgot where we came out on it, so I have to refresh my brain again. Look at the line titled "basin support projects" for Mayo, and that's an $8 million item.

And describe for me again, what are the nature of the basin support projects? What kinds of activities are encompassed by that term?

A. So those are projects, like a wastewater treatment that would will be needed in order to support the closure of the basin, any type of stormwater, processed -- stormwater reroutes that did not need to be done for operation of the plant. If it had to be done for operation of the plant, it would go as a capital. But if it had to be done to remove stormwater from going into the basin and did not need for the operation of the plant, then it would be in this category.

Q. Thank you. That refreshes my recollection, and you explained to me, I now recall that those are considered ARO costs because they are part of the process of closing the basin, you must divert the other waste waterstreams away from the basin. Thank you.

So really let me just ask, then, the final question. On page 16 you say, beginning on line 12, that the Company has incurred several miscellaneous costs including operating and maintenance costs performed on retired and active impoundments.

My question really is, are those included in the basin support project also, ongoing operating and maintenance costs of the active basins?

A. So the operating and maintenance costs -- and that is -- so this is an area where -- the group I have is operation and maintenance as well. So when we have a project at one of the basins that it is an ARO and confirmed with our accounting personnel that it is an ARO, if it's a smaller in nature, like a gopher hole that has to be filled in, or if it -- or a little erosion rail or some vegetation management that is required underneath the dam safety regulations or related to CAMA and CCR, if that can be done with my O&M group who handles true O&M and other areas of the basins, then that small portion, whatever can be tied to the ARO and the obligations under CAMA and CCR, would be charged to the ARO.

When I discussed it in my testimony as being O&M, that's because it's not a separate project. It's not something bigger that we would end up accounting for in a different way, and it would go under a different bucket. It's something that comes out of my organization, the O&M organization, because it's smaller in nature. But it is -- it -- so that's why it got the nomenclature of O&M, because that's what my group does. But working with accounting, it truly is something associated with basin closure and an ARO.

Q. Well, and it would therefore be included in your Table 1? The kinds of things you describe would be included in your Table 1, correct?

A. Yes, they would be. And that other group. I remember you asked me a question about it last time.

Q. It would be in the category titled "other"?

A. And what -- and I dug more into that after last time just to make sure I had it clear what was in that other. So it is vegetation management, aeration, overseeding, herbicide placement related to those basins, repairs to minor erosion. That other section also includes any type of dam inspections, pipe inspections, basin and landfill inspections, and aerial surveys that are required under the CCR rule and CAMA as well. So that bucket kind of captures those that are smaller in nature.

Q. Those would be activities, though, that the Company would be required to undertake if it were continuing to operate those as active impoundments, would they not?

A. I believe they would, but since they're tied to requirements under CCR rule and CAMA when accounting group looked at it, and that's how it's been tied to ARO. And Mr. Doss' supplemental testimony had a chart in it that kind of showed what is an ARO and what is not. So that's one of the reasons why they have that chart, is to make sure -- we want to make sure it's accounted for appropriately.

Q. Okay. Ms. Bednarcik, thank you for being patient with me, and that's all the questions I have.

COMMISSIONER CLODFELTER: That will end the Commissioners' questions unless other Commissioners have other questions you want to come back on. If not, we'll take our morning break and -- my bad, let's come back at 11:20.

(At this time, a recess was taken from 11:04 a.m. to 11:20 a.m.)

COMMISSIONER CLODFELTER: Let's resume. Ms. Bednarcik, one of the perils for you as a witness when we take breaks is that people think of additional questions. And so although I am done, Commissioner Duffley does have some questions for you. Commissioner Duffley.

COMMISSIONER DUFFLEY: Thank you.

EXAMINATION BY COMMISSIONER DUFFLEY:

Q. Good morning. Could you go back to Hart Exhibit Number 12? And it's the Redirect Exhibit Number 1, the June 17, 2011, memo.

A. (Witness peruses document.)

I have it in front of me now.

Q. Okay. I just wanted to receive some clarification. So on page 1 it says it's to the section staff and interested parties.

A. I'm trying to see where it has that on there.

Q. It's in the "to," right under memorandum.

A. Oh, yes, I'm sorry. Yes. The section staff interested parties, yes.

Q. So interested parties would be parties like Duke Energy Progress?

A. Yes.

Q. Okay. And then the section staff that would be determining compliance would be looking at the flow chart that's attached and using that flow chart?

A. Yes.

Q. Okay. If you could go to the flow chart. And as I read this flow chart, there are two -- two AROs to issue a notice of violation.

One is if a groundwater concentration greater than 2L is not reported to the division; do you see that one?

A. Yes.

Q. That box? And then the other way that a division would -- the division would issue a notice of violation is if the permittee is not complying with what DEQ is requiring of it with the corrective action requirements; is that correct?

A. Yes, that is correct.
Q. Okay. I just wanted to make sure I understood the flow chart. Thank you. No further questions.
COMMISSIONER CLODFELTER: All right. Then we're now to questions on the Commissioners' questions. And, Ms. Townsend, do you want to go first or --
MS. TOWNSEND: I have no questions, Commissioner Clodfelter. Thank you.
COMMISSIONER CLODFELTER: Okay. Ms. Cralle Jones.
MS. CRALLE JONES: Likewise, I have no questions.
COMMISSIONER CLODFELTER: Okay. Mr. Marzo? Let me ask, is there anyone else that has questions on Commissioners' questions? If not, Mr. Marzo.
MR. MARZO: Thank you, Commissioner Clodfelter, I just have a couple.
EXAMINATION BY MR. MARZO:
Q. Ms. Bednarcik, Commissioner Clodfelter asked you a number of questions about the timing of dewatering of several basins. This was in a discussion

about inactive and active basins.

Is it your understanding -- well, let me ask you this. Did you review the same materials as Mr. Kerin reviewed in preparation for this case to get your understanding of the timing of dewatering?

A. Yes, I did.

Q. And is your understanding different than what you understood Mr. Kerin to understand in the prior period of time, prior case?

A. No. It was the same as what Mr. Kerin understood. And what I was trying to do as I was talking to Commissioner Clodfelter, I was going off of -- trying to walk my way through all of the different sites and visiting the sites and the basins and remembering their current state and what they look like today.

Q. Okay. Thank you, Ms. Bednarcik. Now, Commissioner Clodfelter also asked you, if you did not have to close the basins, would you have to undertake activities related to assessment, monitoring, and corrective action. Would you expand on that?

A. Yes. So of course there is the 2L regulation, and if -- absent CAMA and CCR, we would have moved forward with some type of actions. But, of course, once CAMA and CCR came on, which CAMA is much more prescriptive -- it has prescriptive requirements in it that we have to follow, and CCR also has different requirements sampling at the waste boundary versus the compliance boundary, and Mr. Wells can talk about that in more detail.

But we would not be able to go back and say, absent CAMA and CCR, what would we have to do, because we're working underneath our current regulations, and we don't know what actions the state may have had us do, any type of corrective actions. Yes, we would have had to do something, but what that looks like, we can't go back and guess what that would be because we are working right now under CAMA and CCR, and that's what we're executing at the sites.

Q. Okay. Thank you, Ms. Bednarcik.

MR. MARZO: Commissioner Clodfelter, that's all the questions I have.

COMMISSIONER CLODFELTER: All right. Thank you, Mr. Marzo. At this point we will entertain any motions relative to Ms. Bednarcik's testimony.

MR. MARZO: I would ask that her Exhibits 1 through 19 be moved into the record, prefiled exhibits, as well as my redirect exhibits.

COMMISSIONER CLODFELTER: As well as your redirect Exhibits 1 through 5, correct?

MR. MARZO: 1 through 5, that's correct.

COMMISSIONER CLODFELTER: Without objection, that motion will be allowed.

(Bednarcik Direct Exhibits 1 through 19, and Bednarcik Direct DEP Redirect Exhibit Numbers 1 through 5 were admitted into evidence.)

COMMISSIONER CLODFELTER: Ms. Townsend.

MS. TOWNSEND: Yes, I would move for Ms. Bednarcik's AGO Direct Exhibits Number 7, making sure I get my numbers right, 7 through 28, I believe was the last exhibit.

COMMISSIONER CLODFELTER: 8 or 28?

MS. TOWNSEND: 28.

COMMISSIONER CLODFELTER: 28.

MS. TOWNSEND: Yes, 7 through 28.

COMMISSIONER CLODFELTER: Okay. The motion is to move into the record Bednarcik Direct AGO Cross Examination Exhibits 7 through 28. Hearing no objection, it will be so ordered.

(Bednarcik Direct AGO Cross Examination

Exhibits 7 through 28 were admitted into evidence.)

COMMISSIONER CLODFELTER: Yes, Ms. Cralle Jones. I think your exhibit was Sierra 1, Ms. Cralle Jones?

MS. CRALLE JONES: I'm sorry. I didn't even -- oh, I apologize. I was not ready. Excuse me. I'd move that Sierra Bednarcik Direct Exhibit 1 be moved into the record.

COMMISSIONER CLODFELTER: According to my notes, that is the only one that was designated. And someone will correct me. Mr. Mehta, if you're out there, correct me, Mr. Mehta, but I think that's correct. So we will accept into the record Bednarcik Direct Sierra Club Exhibit -- Cross Examination Exhibit 1 without objection. So ordered.

(Bednarcik Direct Sierra Club Cross Examination Exhibit 1 was admitted into evidence.)

MR. MARZO: And, Commissioner Clodfelter, I know earlier when I had introduced the exhibits from the stipulation related to the stipulation, I did introduce AGO

Exhibits 1 through 6. I assume all of those go into --

COMMISSIONER CLODFELTER: You are correct. As I say, developing a new set of habits in this new world is very difficult. You are right, you did do those because they were stipulated. My apologies to you and Ms. Cralle Jones, I am still having to learn new habits as well.

MR. MARZO: That's fine.

COMMISSIONER CLODFELTER: Thank you.

MR. MARZO: Thank you, Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Ms. Bednarcik, you'll be back, but you get a break. Thank you.

Mr. Robinson, are you around?

MR. ROBINSON: I'm here, Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Mr. Robinson, I want to go ahead and take your next witness, but I believe that will be the last witness in the Company's case in chief; is that correct?

MR. ROBINSON: That is correct, Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Well, let me, then, tell you that, after we complete your witness, then, if you would like to renew your motion with respect to excusing witness Riley, rebuttal witness Riley, I've determined now that none of the Commissioners have additional questions for Mr. Riley. And so if you would like to renew your motion with regard to his testimony and excusing him at that point, we'll take that at the close of your case in chief. Okay?

MR. ROBINSON: Thank you, sir.

COMMISSIONER CLODFELTER: All right. So that brings us to the next witness, I believe, was to have been a panel, but now it's Ms. Solo, correct?

MS. JAGANNATHAN: That's correct. Molly Jagannathan here on behalf of the Company. And at this time we would like to call witness Kim Smith to the stand.

COMMISSIONER CLODFELTER: Ms. Smith, there you are.

Whereupon,

KIMBERLY D. SMITH,

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

COMMISSIONER CLODFELTER: Okay. Thank you. Ms. Jagannathan.

MS. JAGANNATHAN: Thank you.

DIRECT EXAMINATION BY MS. JAGANNATHAN:

Q. Ms. Smith, would you please state your name and business address for the record?

A. My name is Kim H. Smith, and my business address is 550 South Tryon -- wait a minute. My name is Kim H. Smith, and my business address is 550 South Tryon Street, Charlotte, North Carolina.

Q. And by whom are you employed and in what capacity?

A. I am employed by Duke Energy Carolinas as director of rates and regulatory planning, and I am testifying on behalf of Duke Energy Progress.

Q. And, Ms. Smith, you previously appeared during the consolidated portion of the hearing to testify on the topics of excess deferred income taxes as well as the requested accounting treatment for the grid improvement plan; but you're here today to testify about the remainder of your testimony; isn't that right?

A. That is correct.

Q. And did you prepare a summary of that testimony?

A. Yes, I did.

MS. JAGANNATHAN: And, Commissioner Clodfelter, I would like to move Ms. Smith's DEP-specific testimony summary into the record as if given orally from the stand.

COMMISSIONER CLODFELTER: All right. Without objection, the summary will be taken into the record the same as if given orally from the stand.

(Smith Exhibits 1 through 5; Smith Supplemental Exhibits 1, 2, and 4; Smith Rebuttal Exhibits 1 through 5; Smith Partial Settlement Exhibits 1 through 4; Smith Second Supplemental Exhibits 1 through 3 and 1S through 4S; Smith Corrected Second Supplemental Exhibits 1 through 3 and 1S through 4; Smith Second Settlement Exhibits 1 through 4; and GIP Exhibits 1 through 3 were moved at the consolidated hearing and admitted into evidence.)

(Whereupon, the prefiled direct,

supplemental direct, rebuttal, settlement, second supplemental direct, corrected second supplemental direct, second settlement, testimony of Kimberly D. Smith as well as the joint testimony of Jay W. Oliver and Kim H. Smith were moved at the consolidated hearing and copied into the record as if given orally from the stand along with the testimony summary of Kimberly D. Smith.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of:	)	
	)	**DIRECT TESTIMONY OF**
Application of Duke Energy Progress, LLC	)	**KIM H. SMITH**
For Adjustment of Rates and Charges	)	**FOR DUKE ENERGY**
Applicable to Electric Service in North Carolina	)	**PROGRESS, LLC**

I. INTRODUCTION AND PURPOSE

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

A. My name is Kim H. Smith, and my business address is 550 South Tryon Street, Charlotte, North Carolina. I am a Director of Rates & Regulatory Planning, employed by Duke Energy Carolinas, LLC, ("DE Carolinas"), testifying on behalf of Duke Energy Progress, LLC ("DE Progress" or the "Company").

Q. WHAT ARE YOUR RESPONSIBILITIES IN THIS ROLE?

A. I am responsible for providing regulatory support for retail rates initiatives, including retail rate cases or other significant rates initiatives for DE Progress and DE Carolinas (collectively, the "Utilities").

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from Marshall University with a Bachelor of Science degree in Business Administration, and received a Master of Business Administration degree from the University of Charleston in West Virginia. I am a certified public accountant licensed in the state of North Carolina. I began my career with Duke Energy Business Services ("DEBS") in 2006 as an external reporting manager. I joined the Rates Department in 2008 as Rates Manager and was responsible for providing regulatory support for retail and wholesale rates, providing guidance on the Utilities' Renewable Energy and Energy Efficiency Portfolio Standard ("REPS") compliance, Distributed

Energy Resource Program ("DERP"), and cost recovery applications, energy efficiency cost recovery, and fuel and fuel-related recovery processes. In July 2016, I joined the Regulatory Affairs Department as Regulatory Affairs Manager. I returned to the Rates Department in January 2018.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I testified before the North Carolina Utilities Commission ("NCUC" or the "Commission") in DE Carolinas' 2011 and 2012 REPS compliance and cost recovery applications, Docket No. E-2, Subs 984 and 1008, respectively. I also testified in DE Carolinas' 2013, 2014, 2015 and 2016 fuel and fuel-related cost recovery applications in Docket No. E-2, Subs 1033, 1051, 1072 and 1104, respectively. In addition, I provided supplemental testimony in DE Progress' 2012 REPS cost recovery application in Docket No. E-2, Sub 1020.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to discuss the results of DE Progress' operations under present rates based on an adjusted historical test period using the twelve-month period ended December 31, 2018 (the "Test Period"). I discuss the additional revenue required as a result of the cost of service based on the pro forma costs in the Test Period. I discuss several pro forma adjustments to the Company's Test Period operating expenses and rate base. I request permission to defer as a regulatory asset certain severance costs incurred during the Test Period to be amortized over a three-year period, and I explain the Company's request for approval to defer certain costs related to investments in the transmission and distribution grid under the Company's Grid Improvement Plan. I also explain the accounting requests the Company is making related to establishing regulatory assets for 2019 Hurricane Dorian incremental storm costs; the new Asheville Combined Cycle plant's depreciation expense, property taxes, incremental operations and maintenance ("O&M") expenses and return, from the estimated in-service date of December 2019 until new rates are effective; and the unrecovered costs of the Roxboro Wastewater treatment plant upon retirement. I also request authorization to continue deferring costs related to compliance with coal ash regulations beyond the proposed February 29, 2020 cut-off in this case. I propose a change to the existing excess deferred income taxes ("EDIT") rider (EDIT-1) and the addition of a new EDIT-2 rider to refund federal and state income tax related amounts owed to customers due to the 2017 Tax Cuts and Jobs Act ("Tax Act") and recent reductions to North Carolina state income tax rates. Finally, I propose a new rider, the Regulatory Asset and Liability rider (RAL-1) to follow the Commission directive to refund to customers the net over-amortizations of expired regulatory assets and liabilities since the Company's last base rate case.

Q. DOES YOUR TESTIMONY INCLUDE ANY EXHIBITS?

A. Yes. I have included five exhibits. Smith Exhibit 1 sets forth the operating results under current and proposed base rates. Smith Exhibit 2 summarizes the total revenue adjustments proposed in this proceeding, including the proposed increase in base rates and the net reduction in revenues reflected in existing and proposed riders. Smith Exhibit 3 illustrates the proposed revisions to the previously established North Carolina EDIT-1 rider to customers because of revisions in the federal tax rate that were applied to the original rider. Smith Exhibit 4 illustrates the proposed EDIT-2 rider to refund additional tax benefits to customers, mostly related to the Tax Act. Smith Exhibit 5 illustrates the proposed RAL-1 rider to refund to customers the net over-amortizations of expired regulatory assets and liabilities.

Q. WERE THESE EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes. Smith Exhibits 1 through 5 were prepared under my supervision.

Q. DID YOU PROVIDE ANY INFORMATION INCLUDED IN THE COMPANY'S APPLICATION IN THIS DOCKET?

A. Yes. I provided the pro forma adjustment work papers included in Item 10 of the Form E-1, filed with the Company's Application to Adjust Retail Rates, Request for an Accounting Order and to Consolidate Dockets (the "Application").

II. DETERMINING THE REVENUE REQUIREMENT

Q. WHAT IS THE REVENUE REQUIREMENT AND HOW DID DE PROGRESS CALCULATE IT?

A. The revenue requirement represents the annual revenues necessary for the Company to recover its operating expenses (including depreciation and taxes) and provide its investors with a fair rate of return on the investment in rate base. DE Progress determined its operating costs by identifying depreciation and amortization expense, O&M, fuel expense, taxes, and other expenses charged to utility operations and recorded in its accounting records for the Test Period. The amount of rate base is determined by adding the year-end balances in the Company's accounting records of plant in service, accumulated depreciation, materials and supplies (including fuel inventory) and components of working capital less deferred taxes and operating reserves, including certain regulatory assets and liabilities. Next, a cost of service study is prepared that allocates and assigns these actual Company operating costs and rate base amounts to determine the per book cost for providing electric service to the Company's North Carolina retail operations. The cost of service studies, filed as Item 45 of DE Progress' Form E-1, were reviewed by Witness Janice Hager, and she describes the allocation process and methodologies used by the Company in this proceeding within her testimony.

Following the cost of service study, the actual Test Period expense and rate base levels, as allocated to the North Carolina retail operations, were adjusted for known and measurable changes, as described below and in the testimony of Witnesses Michael Pirro and Kimberly McGee. DE Progress made certain accounting and pro forma adjustments to actual operating income and rate base for the Test Period to reflect known and measurable changes to (i) normalize for abnormal events; (ii) annualize part year recurring effects to a full year effect; and (iii) show actual changes in costs, revenues or the cost of the Company's property used and useful, or to be used and useful within a reasonable time after the Test Period, in providing service.

After the determination of operating expenses and rate base for the Company's North Carolina retail operations, rate base is split between the Company's debt investors and equity investors using the Company's proposed capital structure of 47 percent debt and 53 percent equity. Then, the annual cost of debt is calculated. The income available for the Company's equity investors is determined by subtracting the cost of debt from the operating income produced by the current revenues received from North Carolina retail customers less operating expenses. Finally, the required revenue increase necessary to produce the requested equity return on the amount of the equity invested in rate base is determined.

Smith Exhibit 1 sets forth the rate base, operating revenues, operating expenses, and operating income the Company earned during the Test Period and the adjusted amounts the Company supports for use in calculating its proposed revenue requirement. In Exhibit 1, I have indicated by asterisk the items the Company plans to update in this proceeding.

III. RESULTS OF OPERATIONS UNDER EXISTING AND PROPOSED RATES

Q. PLEASE DESCRIBE SMITH EXHIBIT 1 TO YOUR TESTIMONY.

A. Smith Exhibit 1 sets forth the operating results and data required by Commission Rule R1-17(b) regarding operating income, calculation of additional revenue requirement, accounting adjustments, and rate base information. The operating results are based on the Test Period noted above, using the twelve-months ended December 31, 2018, with appropriate adjustments. This information is also shown on Pages 1 through 4d of Exhibit C of the Company's Application.

Q. PLEASE EXPLAIN WHAT IS PRESENTED ON PAGE 1 OF SMITH EXHIBIT 1 ENTITLED "OPERATING INCOME FROM ELECTRIC OPERATIONS."

A. Smith Exhibit 1, Page 1 summarizes the Company's operating income from electric operations for the Test Period both for total Company operations and North Carolina retail operations before the necessary accounting adjustments. It also shows the Company's operating income from electric operations for North Carolina retail operations after the necessary accounting adjustments and the rate of return on North Carolina retail rate base the Company would earn in the Test Period after reflecting those adjustments.

Columns 1 and 2 set forth the actual operating revenues, expenses and rate base from the per book cost of service study (Form E-1, Item 45a) for the Company and for its North Carolina retail jurisdiction, respectively.

Column 3 summarizes the accounting adjustments allocated to North Carolina retail operations necessary to reflect a representative level of operating income and rate base based on known changes in costs. These adjustments are shown on Smith Exhibit 1, Page 3 and are explained later in my testimony.

Column 4 shows adjusted North Carolina retail operations.

Column 5, Line 1 shows the additional base rate revenue requested in this proceeding of $585.9 million. This is the increase in revenues justified as necessary to cover the Company's cost of service, including a rate of return on members' equity of 10.30 percent as discussed in the testimony of Witnesses Robert Hevert and Karl Newlin. Column 5 also shows the effect of the revenue increase on the NCUC regulatory fee, uncollectibles expense, income taxes, and cash working capital.

Column 6, Line 11 shows adjusted operating income after the proposed increase in revenues. Column 6, Line 12 shows the adjusted retail rate base. Dividing operating income by rate base produces the 7.41 percent overall rate of return that the Company is justifying in this case, as shown in Column 6, Line 13.

Q. PLEASE EXPLAIN WHAT IS PRESENTED ON PAGE 2 OF SMITH EXHIBIT 1 ENTITLED "CALCULATION OF ADDITIONAL REVENUE REQUIREMENT."

A. Page 2 sets forth the calculation of the additional revenue requirement necessary to produce a 10.30 percent rate of return on members' equity using the format required by Commission Rule R1-17(b)(9)e. To develop this figure, the North Carolina retail rate base was allocated to its capital source components of long-term debt and members' equity. This allocation was based on the capitalization ratios of 47 percent long-term debt and 53 percent members' equity. Witness Newlin discusses and supports these ratios in his testimony.

The amount of operating income needed to cover interest applicable to North Carolina retail rate base was computed using the embedded cost of long-term debt rate. This amount is shown in Columns 4 and 7 on Line 1. Operating income needed to cover interest, shown in Columns 5 and 8 on Line 1, was deducted from total operating income shown in Column 5 on Line 3, to derive operating income remaining for members' equity at present rates as shown in Column 5 on Line 2.

Applying the 10.30 percent rate of return on members' equity to that portion of the North Carolina retail rate base financed by members' equity, shown in Column 6, Line 2 produces the operating income requirement for members' equity as shown in Column 8, Line 2.

The total operating income requirement shown in Column 8, Line 3 is the sum of the requirements for long-term debt and members' equity. Comparing the operating income requirement to the operating income before the proposed increase in Column 5, Line 3 results in the additional operating income requirement shown in Column 8, Line 5. To realize this additional operating income, the Company must also collect in revenues the increase for the NCUC regulatory fee (less the uncollectible rate) at a rate of 0.1297 percent, uncollectibles expense at a rate of 0.2394 percent, state and federal income taxes at a composite rate of 23.1693 percent, and the return on cash working capital requirements. The additional operating income requirement and the additional taxes and fees produces an additional revenue requirement of $585.9 million.

Q. PLEASE EXPLAIN THE PURPOSE OF SMITH EXHIBIT 2 ENTITLED "SUMMARY OF PROPOSED REVENUE ADJUSTMENTS."

A. Smith Exhibit 2 summarizes the total change in revenue requirement requested in this proceeding. As stated above, the requested increase in revenues from base rates is $585.9 million. In addition to increased revenue from tariff rates for electric service, the Company requests that customer rates be increased by $7.4 million, as presented in Smith Exhibit 3, through a revision in the existing North Carolina EDIT-1 rider and decreased by $127.6 million, as presented in Smith Exhibit 4, through the proposed EDIT-2 rider. The two EDIT riders represent amounts due from or owed to customers related to tax rate changes and EDIT, in addition to what is reflected in the proposed revenue increase in Smith Exhibit 1. Also, as presented in Smith Exhibit 5, the Company requests that customer rates be decreased by $2.1 million, through the RAL-1 rider, as a result of regulatory assets or liabilities that have been over-amortized since the last rate case. As shown on Smith Exhibit 2, the total proposed increase in revenue is $463.6 million.

Q. PLEASE EXPLAIN WHAT IS PRESENTED ON PAGE 1 OF SMITH EXHIBIT 3 ENTITLED "2018 NC EDIT RIDER REVISED FOR THE CHANGE IN FEDERAL INCOME TAX RATE FROM 35% TO 21% DUE TO THE FEDERAL TAX CUTS AND JOBS ACT."

A. Since March 2018, DE Progress has been flowing back excess North Carolina EDIT to customers through a levelized North Carolina EDIT rider (EDIT-1) that will expire at the end of a four-year period pursuant to the Commission's February 23, 2018 *Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase* in DE Progress' general rate case in Docket No. E-2, Sub 1142 ("Sub 1142 Order"). Since the North Carolina EDIT-1 rider amount and rate approved in the prior rate case used a 35 percent federal tax rate for the tax gross-up, the Company proposes revising the EDIT-1 rider as recalculated using the new 21 percent federal tax rate as shown in Smith Exhibit 3. This recalculation reduces the currently approved EDIT-1 rider revenue decrement from $42.6 million to $35.2 million.

Q. PLEASE EXPLAIN THE PURPOSE OF SMITH EXHIBIT 4 ENTITLED "EXCESS DEFERRED INCOME TAX RIDER CALCULATION."

A. Smith Exhibit 4 illustrates the proposed rider to refund various categories of EDIT to customers, including federal EDIT, North Carolina EDIT related to the 2019 change in the tax rate from 3% to 2.5%, and deferred revenue because of the federal Tax Act, as explained further in my testimony below.

Q. PLEASE EXPLAIN THE PURPOSE OF SMITH EXHIBIT 5 ENTITLED "REGULATORY ASSET AND LIABILITY RIDER ("RAL-1")."

A. Per Ordering Paragraph 32 of the Sub 1142 Order, if DE Progress receives revenue for any deferred cost for a longer period than the amortization period approved by the Commission for that deferred cost, the Company shall continue to record all revenue received for the deferred cost in the specific regulatory asset account established for that deferred cost until the Company's next general rate case. To comply, DE Progress has continued to record all revenue received for deferred amounts related to regulatory asset and liability accounts until the Company's next rate case. Smith Exhibit 5 shows the calculation of the resulting net over amortization balance. The Company is proposing a rider (RAL-1) to return this balance to customers over a one-year period.

Q. HOW IS THIS ADDITIONAL REVENUE REQUIREMENT ALLOCATED AMONG THE CLASSES AND USED TO DEVELOP THE TARGET REVENUE REQUIREMENT FOR RATE DESIGN?

A. Witness Pirro's Exhibit 4 shows how the additional revenue requirement is spread among the classes and how the target revenue requirements for rate design are established.

IV. ACCOUNTING AND PRO FORMA ADJUSTMENTS

Q. PLEASE EXPLAIN PAGE 3 OF SMITH EXHIBIT 1 CAPTIONED "DETAIL OF ACCOUNTING ADJUSTMENTS - NORTH CAROLINA RETAIL."

A. Page 3 sets forth the individual accounting and pro forma adjustments to operating revenues, expenses and rate base, including the income tax effects for North Carolina retail electric operations, that were shown in total on Page 1 of Smith Exhibit 1 in Column 3. The totals of the columns shown on Line 36 of Page 3 are the amounts carried forward to Column 3 of Page 1 of Smith Exhibit 1.

Q. PLEASE LIST THESE ACCOUNTING AND PRO FORMA ADJUSTMENTS.

A. The accounting and pro forma adjustments that were made by the Company are as follows (the chart below indicates which witness is sponsoring each adjustment):

ADJUSTMENTS TO OPERATING REVENUES AND EXPENSES (Page 3 of Smith Exhibit 1)		
Line No.	**Adjustment Title**	**Witness**
1	Annualize retail revenues for current rates	Pirro
2	Update fuel costs to proposed rate	McGee
3	Normalize for weather	Pirro
4	Annualize revenues for customer growth	Pirro
5	Eliminate unbilled revenues	Smith
6	Adjust for costs recovered through non-fuel riders	Smith
7	Adjust O&M for executive compensation	Smith
8	Annualize depreciation on year end plant balances	Smith
9	Annualize property taxes on year end plant balances	Smith
10	Adjust for post test year additions to plant in service	Smith
11	Amortize deferred environmental costs	Smith
12	Annualize O&M non-labor expenses	Smith
13	Normalize O&M labor expenses	Smith
14	Update benefits costs	Smith
15	Levelize nuclear refueling outage costs	Smith
16	Amortize rate case costs	Smith
17	Adjust aviation expenses	Smith
18	Adjust for approved regulatory assets and liabilities	Smith
19	Adjust for merger related costs	Smith
20	Amortize severance costs	Smith
21	Adjust for NC income tax rate change	Smith
22	Synchronize interest expense with end of period rate base	Smith
23	Adjust cash working capital for present revenue annualized and proposed revenue	Smith

ADJUSTMENTS TO OPERATING REVENUES AND EXPENSES (Page 3 of Smith Exhibit 1)		
Line No.	**Adjustment Title**	**Witness**
24	Adjust coal inventory	Smith
25	Adjust for credit card fees	Smith
26	Adjust depreciation for new rates	Smith
27	Adjust vegetation management expenses	Smith
28	Adjust reserve for end of life nuclear costs	Smith
29	Update deferred balance and amortize storm costs	Smith
30	Adjust other revenue	Pirro
31	Adjust for change in NCUC regulatory fee	Smith
32	Reflect retirement of Asheville Steam Generating Plant	Smith
33	Adjust for CertainTeed payment obligation	Smith
34	Amortize deferred balance Asheville Combined Cycle	Smith
35	Adjust purchased power	Smith

Q. IN CALCULATING THE TOTAL REVENUE REQUIREMENT IN THIS PROCEEDING, DID YOU REVIEW EACH OF THE ACCOUNTING AND PRO FORMA ADJUSTMENTS?

A. Yes, I did.

Q. IN YOUR OPINION, DO THESE ACCOUNTING AND PRO FORMA ADJUSTMENTS REFLECT KNOWN AND MEASURABLE CHANGES TO THE COMPANY'S TEST PERIOD OPERATING EXPENSES, REVENUES, AND RATE BASE?

A. Yes. The adjustments set forth on Page 3 of Smith Exhibit 1, as more fully supported below and in the testimony of Witnesses McGee and Pirro, reflect known and measurable changes to the Company's Test Period revenues, expenses, and rate base.

Q. PLEASE DESCRIBE THE PRO FORMA ADJUSTMENTS YOU ARE SUPPORTING.

A. The following are descriptions of the pro forma adjustments:

1. Annualize retail revenues for current rates

This adjustment annualizes revenue based on the base rates in effect at the time of the Application, excluding the REPS Rider and removes Test Period revenues recovered through the Demand-Side Management/Energy Efficiency ("DSM/EE") Rider, the Joint Agency Acquisition Rider ("JAAR"), the EDIT-1 Rider, Fuel Experience Modification Factor ("EMF") Deficiency Rider, and the December 2018 Fuel EMF. This adjustment also includes the removal of the provision for rate refund recorded in the Test Period related to the federal tax rate change. This adjustment to revenues is discussed in more detail in the testimony of Witness Pirro. The revenues recovered through the REPS Rider are removed in Adjustment Line 6.

2. Update fuel costs to proposed rate

This adjustment adjusts fuel clause expense during the Test Period to match the fuel clause revenues included in Adjustment Line 1. By matching the expenses to the revenue, the adjustment ensures that no increase is requested in this proceeding related to fuel and fuel-related expenses that are recoverable through the fuel clause. This adjustment is described in more detail in Witness McGee's testimony.

3. Normalize for weather

This adjustment adjusts revenue to normalize for the impacts of weather. The kWh weather adjustment was developed based on a 30-year history of weather. This kWh adjustment was then multiplied by an average rate for each class to derive the adjustment to revenue. The average rate is based on annualized Test Period revenues at current base rates, therefore excluding the rates for the riders identified in Adjustment 1. However, since the rate includes the base fuel rate proposed in this case, an adjustment is also made to fuel expense to reflect the change in kWh due to weather adjustment. This adjustment is described in more detail in Witness Pirro's testimony.

4. Annualize revenues for customer growth

This adjustment annualizes revenue to reflect expected changes in Test Period kWh sales related to changes in the number of customers and usage per customer, using actual and estimated 2019 data and weather-normalized values. The net kWh adjustment was then multiplied by an average rate for each class to derive the adjustment to revenue. The average rate is based on annualized Test Period revenues at current base rates, therefore excluding the rates for the riders identified in Adjustment 1. However, since the rate includes the base fuel rate proposed in this case, an adjustment is also made to fuel expense to reflect the annualized change in kWh. This adjustment is described in more detail in Witness Pirro's testimony.

5. Eliminate unbilled revenues

This adjustment eliminates unbilled revenue and related taxes recorded by the Company in the Test Period.

6. Adjust for costs recovered through non-fuel riders

This adjustment removes expense and rate base items recovered through the Company's non-fuel riders. The revenues, expenses and rate base items, if applicable, in each of these riders are reviewed each year in annual rider proceedings and should not impact the increase requested in this proceeding. Any deferred revenues related to these riders are also removed in this adjustment.

7. Adjust O&M for executive compensation

This adjustment removes 50 percent of the compensation of the five Duke Energy executives with the highest level of compensation allocated to DE Progress in the Test Period. While the Company believes these costs are reasonable, prudent and appropriate to recover from customers, we have for purposes of this case, made an adjustment to this item.

8. Annualize depreciation on year-end plant balances

This adjustment reflects the annualization of depreciation expense using the current depreciation rates applied to the end of the Test Period level of plant in service. During the Test Period, the Company recorded depreciation for plant additions from the point in time they went into service. This adjustment annualizes depreciation expenses to reflect a full year level of depreciation on plant in service as of the end of the Test Period using the depreciation rates that were in effect by the end of the Test Period. Amounts for changes in catalyst depreciation expense are excluded from this adjustment due to catalyst depreciation expense being recovered through the fuel clause.

9. Annualize property taxes on year end plant balances

This adjustment annualizes Test Period property taxes on plant in service at December 31, 2018. Property taxes expensed in the calendar year 2018 were assessed based on property balances at the end of 2017. Likewise, property taxes to be expensed in calendar year 2019 will be assessed based on property balances at the end of 2018. This adjustment increases property tax expense in the Test Period to reflect an annual level of expense for property taxes based on the end of the Test Period level of plant investment.

10. Adjust for post test year additions to plant in service

This adjustment increases operating expenses and rate base for changes in plant, depreciation expense, and accumulated depreciation the Company has incurred and will incur from the end of the Test Period through February

29, 2020. Amounts for changes in plant, depreciation expense, and accumulated depreciation related to assets expected to be recovered in the JAAR and DSM/EE riders are excluded from this adjustment. Witnesses Kelvin Henderson, Julie Turner, Don Schneider and Jay Oliver discuss plant additions in their testimonies.

11. Amortize deferred environmental costs

In the Sub 1142 Order, the Commission granted the Company authority to defer in a regulatory asset account certain costs incurred in connection with compliance with federal and state environmental requirements as it relates to Coal Combustion Residuals ("CCRs" or "coal ash"). The nature of these costs is described in more detail in Witnesses Jessica Bednarcik and Turner's testimony. Most of the deferred compliance costs are related to ash basin closure and are subject to asset retirement obligation ("ARO") accounting per Generally Accepted Accounting Principles ("GAAP"). In addition, a portion of the deferred amounts are related to the continued operation of the active plants and are not subject to ARO accounting. These deferred amounts are revenue requirements related to capitalized plant in service amounts. No fines, penalties, or costs of which DE Progress has agreed to forgo recovery are included in the deferral. This adjustment amortizes the deferred costs over a five-year period. The compliance costs are based on actuals as of the end of the Test Period plus a projection through February 29, 2020. Over the five-year amortization period, the annual amortization expense is $106.0 million. When added together with the net of tax return on the unamortized balance of $29.5 million, the total revenue requirement requested in this case for deferred coal ash pond closure costs is $135.5 million. The Company requests Commission authorization to continue to defer this type of environmental cost beyond the February 2020 cutoff period, for cost recovery consideration in a future rate case.

12. Annualize O&M non-labor expenses

This adjustment annualizes certain Test Period O&M expenses to reflect the change in unit costs that occurred during this period. O&M costs addressed in other adjustments are excluded from this adjustment. The excluded costs include fuel, purchased power, non-fuel rider costs, nuclear refueling outage costs, aviation expenses, atypical severance costs, vegetation management expenses, the NCUC regulatory fee, rate case amortizations, outside tax services, expiring amortizations, merger related costs, the CertainTeed payment obligation, and labor costs.

13. Normalize O&M labor expenses

This adjustment adjusts the wages and salaries, related employee benefits, and changes in related payroll taxes to reflect annual levels of costs as of June 30, 2019. This adjustment also restates variable short and long term pay to the target level.

14. Update benefits costs

This adjustment updates the Test Period cost of labor-related benefits to match the result of an updated study performed by the Company's consultants.

15. Levelize nuclear refueling outage costs

In the Company's 2013 rate case, in Docket No. E-2, Sub 1023, the Commission approved an accounting mechanism that levelized certain costs related to nuclear refueling outages. Consistent with the Company's 2017 rate case in Docket No. E-2, Sub 1142, this adjustment annualizes the amortization expense related to this mechanism incurred during the Test Period to the latest known and measurable level experienced through the capital cutoff period.

16. Amortize rate case costs

This adjustment amortizes the incremental rate case costs incurred for this docket over a five-year period.

17. Adjust aviation expenses

This adjustment removes from expense 50 percent of certain corporate related aviation expenses incurred in the Test Period.

18. Adjust for approved regulatory assets and liabilities

This adjustment removes from Test Period costs the amortization of various regulatory assets or liabilities that have been approved by the Commission in previous general rate case proceedings. The amortization period for items removed will expire before proposed new rates are effective, and thus should not be included in Test Period expenses on which new rates are based. The adjustment also annualizes the Test Period amortizations that were approved in the Sub 1142 Order.

19. Adjust for merger related costs

This adjustment removes the impact of costs related to the Piedmont and Progress mergers included in the Test Period, as adjusted by other proformas.

20. Amortize severance costs

This adjustment removes atypical severance and retention costs included in the Test Period. The Company is also requesting permission in its Application to establish a regulatory asset to defer a North Carolina retail amount of $34.9 million of severance costs, and to amortize the regulatory asset over a three-year period.

21. Adjust for NC income tax rate change

This adjustment adjusts current and deferred income tax expense to reflect the reduction in the North Carolina income tax rate from 3 percent to 2.5 percent effective January 1, 2019.

22. Synchronize interest expense with end of period rate base

This adjustment adjusts income taxes for the tax effect of the annualization of interest expense reflected in the pro forma cost of service.

23. Adjust cash working capital for present revenue annualized and proposed revenue

This adjustment adjusts cash working capital to incorporate the impact of the other pro forma adjustments. It also calculates the additional cash working capital required due to the proposed increase in rates. The adjustment is in accordance with the Commission's March 21, 2016 Order in Docket No. M-100, Sub 137, and is shown on Line 1, Columns 3 and 5, of Smith Exhibit 1, Page 4d.

24. Adjust coal inventory

This adjustment increases the Company's actual coal inventory value at the end of the Test Period to reflect a targeted 35-day full load burn for each of the coal generating plants. This change in coal inventory for the North Carolina retail jurisdiction is shown on Smith Exhibit 1, Page 4c, Line 1, Column 3.

25. Adjust for credit card fees

This adjustment increases O&M expenses to include fees currently incurred by residential customers when using a credit card as the method of payment. As described in the testimony of Witness James Henning, the Company is proposing to implement a transaction fee-free payment program for residential customers. The Company proposes to recover the cost of the program from all customers.

26. Adjust for new depreciation rates

This adjustment adjusts the annualized depreciation expense to reflect the new depreciation rates based on the updated depreciation study prepared by Gannett Fleming and discussed and supported by Witness John Spanos. The proposed new depreciation rates reflect revised life spans for certain coal plants (Mayo Unit 1, Roxboro Units 3 & 4), as noted by Witness Spanos. Implementing the new depreciation rates will result in an increase to depreciation expense of approximately $145.0 million on a system basis, or

$89.6 million on a North Carolina retail basis. The adjustment also increases depreciation reserves by an annual amount of the depreciation expense adjustment.

27. Adjust vegetation management expenses

This adjustment adjusts the mileage to a normalized level and increases O&M expense in the Test Year to reflect known contract rate increases that took effect in 2019.

28. Adjust reserve for end of life nuclear costs

In the Company's 2013 rate case, Docket No. E-2, Sub 1023, the Commission allowed DE Progress to establish reserves for end-of-life costs associated with nuclear materials and supplies and with nuclear fuel. This adjustment adjusts the Test Period amortization expense, reserve and related taxes to reflect updated estimates of the end-of-life costs.

29. Update deferred balance and amortize storm costs

This adjustment reflects a 15-year amortization of deferred costs related to incremental storm damage expenses incurred during the 2018 test year due to Hurricanes Florence and Michael, Winter Storm Diego, and 2019's Hurricane Dorian. The Company previously requested deferral treatment for Hurricanes Florence, Michael, and Winter Storm Diego in Docket No. E-2, Sub 1193, which is currently pending before the Commission. In its Application, the Company requests consolidation of Docket No. E-2, 1193 with this proceeding, and is also requesting deferral treatment for costs related to Hurricane Dorian restoration efforts, as discussed later in my testimony. The Company is proposing to recover the incremental cost in excess of normal storm expenses, including a return on the unrecovered balance. The Company proposes to begin amortization of the costs when proposed new base rates become effective, and to include a return on the deferred balance through the end of the proposed amortization period. Over the 15-year amortization period, the North Carolina retail annual amortization expense is $43.7 million. When added together with the net of tax return on the unamortized balance of $42.6 million, the total revenue requirement requested in this case for deferred incremental storm damage expenses is $86.3 million. Witness Rufus Jackson discusses the scope of storm costs requested for recovery.

30. Adjust other revenues

This adjustment reflects proposed reductions to customer fees related to connection, reconnection, and returned payments, as described by Witness Pirro in his direct testimony.

31. Adjust for change in NCUC regulatory fee

This adjustment annualizes the Test Period regulatory fee at the current rate of 0.13 percent.

32. Reflect retirement of Asheville Steam Generating Plant

This adjustment reflects reductions in O&M expenses, income taxes, depreciation and amortization expense, electric plant in service and accumulated depreciation associated with the retirement of the Asheville Steam Electric Generating Plant. It also adjusts for the regulatory asset established due to the early retirement of the plant, which was previously approved by the Commission in the Sub 1142 Order. The amortization period will last until the original retirement date, December 2027, or approximately seven years.

33. Adjust for CertainTeed payment obligation

This adjustment reflects additional O&M expenses as a result of a settlement agreement with CertainTEED Gypsum NC, Inc. ("CertainTEED"). These are the same O&M expenses currently at issue in the Company's most recent fuel and fuel-related charge adjustment proceeding in Docket No. E-2, Sub 1204. This adjustment serves as a placeholder in the event the Commission determines, in Docket No. E-2, Sub 1204, that the CertainTEED expenses are not eligible for recovery through the fuel clause.

Similar to Docket No. E-2, Sub 1204, the impact to O&M expense was determined by a payment schedule defined in a confidential settlement agreement effective October 1, 2018. Under the settlement agreement, DE Progress is required to make annual payments to CertainTEED from 2018 through 2029 for a total of $88.9 million on a system basis. The amount is allocated to North Carolina retail based on the energy allocation factor, and recovered over an 11-year period to align with the payment period.

34. Amortize deferred balance of Asheville Combined Cycle

This adjustment reflects additional depreciation expense, and income taxes for the amortization of deferred costs and additional O&M expense and materials and supplies related to the Asheville Combined Cycle plant. The Company is seeking a deferral of depreciation, property taxes, incremental O&M and return associated with the Asheville Combined Cycle from the date the plant is expected to go into operation, December 2019, until rates are effective in September 2020.

35. Adjust purchased power

This adjustment removes purchased power expense for purchased power agreements expiring before the end of the Test Period and to add or annualize purchased power expense for signed purchased power agreements that start after the beginning of the Test Period but within a reasonable period after the end of the Test Period.

Q. PLEASE EXPLAIN WHAT IS PRESENTED ON PAGES 4 THROUGH 4d OF SMITH EXHIBIT 1.

A. Page 4 shows total Company and North Carolina retail components of original cost rate base. The total Company amounts and North Carolina retail components were taken from the Company's Cost of Service Study as of December 31, 2018.

Pages 4a, 4b, 4c, and 4d are details of components making up original cost rate base as of December 31, 2018 adjusted for known and measurable changes. On each of these four pages, Column 1 shows the total Company per book amounts at December 31, 2018; Column 2 reflects the amount for North Carolina retail electric operations; Column 3 sets forth the accounting adjustments allocated to North Carolina retail operations; and Column 4 reflects the North Carolina retail amounts including adjustments.

Page 4a is a summary of the Company's investment in electric plant in service as of December 31, 2018 by functional classification. Page 4b details accumulated depreciation and amortization for each of the classes of electric plant in service. The depreciation rates for each class of property are shown at the bottom of the page on Lines 8 through 15. These depreciation rates are supported by Witness Spanos. Page 4c is a summary of the Company's investment in materials and supplies as of December 31, 2018 included in rate base. Page 4d reflects the working capital investment included in rate base.

V. <u>EDIT-2 RIDER</u>

Q. HOW HAS THE COMPANY ADJUSTED ITS RATES TO REFLECT THE TAX IMPACTS OF THE TAX ACT?

A. The reduction in federal income tax rate, from 35 percent to 21 percent, as provided in the Tax Act became law on December 22, 2017. The Company began deferring the additional revenues associated with this reduction in income tax rates starting January 1, 2018 through service rendered November 30, 2018 into a regulatory liability account. In its order dated November 26, 2018 in Docket No. M-100, Sub 148, the Commission approved a $0.00278 per kWh base rate decrement proposed by the Company to pass through the tax benefits of the federal tax rate reduction. Accordingly, the Company commenced passing through the revenue impacts of the reduction in the federal income tax rate to customers starting December 1, 2018. This decrement is eliminated through the proposed rates in this proceeding, which reflect the new lower federal tax rate of 21 percent.

In its order dated October 5, 2018 in Docket No. M-100, Sub 148, the Commission also addressed the disposition of EDIT that results from the reduction in the federal income tax rate, ordering that the Company should maintain the EDIT in a regulatory liability account for three years or until its next general rate case, whichever is sooner. In compliance, in this current proceeding, the Company is proposing a method of returning EDIT to its customers through a rider.

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED EDIT-2 RIDER.

A. In his direct testimony, Witness John Panizza discusses in detail the implications of the Tax Act and North Carolina retail customers' share of the federal income tax amounts that are addressed in the EDIT-2 rider. The rider contains the following five categories of benefits for customers, of which the first three are discussed by Witness Panizza in his testimony:

1. Federal EDIT - Protected
2. Federal EDIT – Unprotected, PP&E related
3. Federal EDIT – Unprotected, non-PP&E related
4. Deferred revenue - Federal income tax
5. North Carolina EDIT

Federal EDIT – Protected, Unprotected PP&E related, and Unprotected, non-PP&E related

At the end of 2018, the Company had a certain amount of Accumulated Deferred Income Taxes ("ADIT") on its balance sheet. These are income taxes the Company has expensed for accounting purposes and collected from customers, but will not need to pay the IRS until some point in the future. Because the Company has use of this cash for a period of time, until it must pay the IRS, the ADIT is included as a reduction to rate base and is a source of financing for investments used to benefit customers – poles, lines, generating plant, etc. With the change in the federal tax rate, the amount of income tax that the Company must pay the IRS in the future has been reduced, and must be remeasured. At the end of 2018, the Company calculated this reduction and the difference was reclassified from ADIT to EDIT, although both ADIT and EDIT remain components of rate base. Instead of having an obligation to pay the EDIT amount to the IRS in the future, the Company now has an obligation to refund it to customers.

Within EDIT, there are three subcategories, as described by Company Witness Panizza.

- Protected – These amounts are generally related to Property, Plant & Equipment ("PP&E") and there are specific IRS requirements mandating that this amount be returned to customers no more quickly than as prescribed by the IRS. The amortization period the Company is using for Protected EDIT is called the Average Rate

Assumption Method ("ARAM") and results in a Year 1 amortization rate for this category of 3.70 percent. Also, as Witness Panizza notes, protected amounts ultimately become unprotected over time. As such, the Company estimated this amount and captured this transition from the Protected to Unprotected category on Smith Exhibit 4, Page 1, Line 3.

- Unprotected PP&E related – These amounts are also related to PP&E but do not fall under the IRS guidelines for protected status. Because the Company would have paid these amounts to the IRS over the remaining life of the underlying property, the Company is proposing to return these amounts to customers over a 20-year period. As noted by Witness Panizza, this approach balances the customer and the Company's interests; minimizing customer rate volatility and addressing the Company's cash flow concerns.
- Unprotected non-PP&E related – These amounts are not related to property, plant and equipment, but are related to items such as regulatory assets and liabilities, and other balance sheet items. The Company is proposing to return these amounts to customers over a five-year period. In addition, the Company has included in this category amounts transitioning from the Protected category to Unprotected status.

<u>North Carolina EDIT</u>

Similar to the EDIT that results from the reduction in the federal corporate income tax rate, there are EDIT balances that resulted from the reduction in the North Carolina state corporate tax rate. In the Company's last general rate case in Docket No. E-2, Sub 1142, the Commission approved a 4-year State EDIT rider (EDIT-1) to return EDIT resulting from reductions in state tax rate in prior years. The State EDIT-1 rider currently in place does not include EDIT related to the reduction in North Carolina state corporate tax rate from 3 percent to 2.5 percent effective January 1, 2019. The Company is proposing to incorporate the refund related to this reduction in the North Carolina state corporate tax rate from 3 percent to 2.5 percent in the EDIT-2 rider proposed in this case, over a 5-year period.

<u>Deferred Revenue</u>

As directed in Docket No. M-100, Sub 148, the Company began deferring, effective January 1, 2018, the impact on customer rates of the reduction in the federal corporate income tax rate from 35 percent to 21 percent. Beginning December 1, 2018, a new rate decrement approved by the Commission in Docket No. M-100, Sub 148 reflected the lower federal tax rate. After December 1, 2018, deferral amounts are related to continuing accrual of returns on the deferral balance. Smith Exhibit 4, Page 1, Line 8, shows the projected balance of this liability as of February 2020. The Company will continue to defer the impact from March 1, 2020 through the new rates effective date in this case. Those additional amounts are not being estimated now but will be included in the Year 2 EDIT-2 rider calculation.

The Company is proposing to incorporate the refund of these deferred revenues in the EDIT-2 rider proposed in this case, over a two-year period.

Q. PLEASE EXPLAIN HOW THESE FIVE CATEGORIES OF BENEFITS WILL BE INCORPORATED INTO THE EDIT-2 RIDER.

A. The proposed EDIT-2 rider will include the annual amortization for each of these five categories of benefits. The North Carolina retail amounts can be seen on Smith Exhibit 4, Page 1, Columns A through E. Since these EDIT amounts are a reduction in rate base, rate base will increase as these amounts are refunded to customers. As such, the rider also calculates the adjustment to return on rate base related to the increase in rate base resulting from the refund of EDIT to customers. This is shown in Smith Exhibit 4, Page 2, Column L. Column M shows the revenue requirement equal to the sum of the amortization and return. Column N shows the revenue requirement grossed up for NCUC regulatory fee and uncollectible expense. The amount in the Year 1 row on Smith Exhibit 4, Page 2 of $127.6 million decrease is the rider amount that is being proposed in this case.

The Year 1 rider amounts are based on the balance of EDIT at December 31, 2018 as described by Witness Panizza, and are updated to reflect the expected balance at August 31, 2020, when the proposed rider is expected to be implemented. This projection will be further updated to reflect actual February 29, 2020 balances, as well as the latest ARAM rate, prior to the hearing.

Years 2 through 5 are shown for illustrative purposes. The actual rider amounts for those years may change based on several factors. First, if there are additional adjustments to any of the balances on Rows 1 through 5 of Smith Exhibit 4, the annual amortization amounts will be recalculated to accommodate the change in balance.

A second factor that would impact the calculation of the rider beyond Year 1 is changes in the ARAM rate. The Company updates this rate annually and the most current rate must be used when establishing customer rates.

A third factor that would impact the calculation of the rider beyond Year 1 is the impact of future rate cases. In future rate cases, the EDIT balance in base rates shown in Column J and the rate of return used to calculate Column L of Smith Exhibit 4, Page 2 would be updated based on what is approved in that case.

Finally, the retention factor used to calculate Column N will be updated to reflect any future changes in the NCUC regulatory fee.

The Company proposes to file the rider amounts, along with the spread to the classes and derivation of the rate for each subsequent year, with the Commission annually in this docket by September 30, for rider rates effective December 1.

The Year 1 EDIT-2 revenue requirement, shown in Smith Exhibit 4, was provided to Witness Pirro who explains the derivation of the rider rate in his testimony. Witness Hager explains how the amounts were allocated to the customer classes in her testimony.

VI. PETITION FOR ACCOUNTING ORDER TO DEFER GRID IMPROVEMENT PLAN COSTS

Q. WHAT IS THE COMPANY'S PROPOSAL REGARDING RECOVERY OF COSTS RELATED TO GRID IMPROVEMENT PLAN INVESTMENTS?

A. The proposed new rates requested in this proceeding include recovery of Grid Improvement Plan expenditures that are included in the Test Period and any supplemental updates that may be made for post Test Period plant additions. In addition, the Company requests permission to defer costs related to its Grid Improvement Plan in a regulatory asset, for cost recovery consideration in future general rate cases. The Company requests authorization to begin deferring incremental costs not included in this case beginning on January 1, 2020. The Grid Improvement Plan is a three-year plan, spanning calendar years 2020 through 2022.

Q. WHAT SPECIFIC COSTS ARE REQUESTED TO BE DEFERRED?

A. Company Witness Oliver extensively discusses the Company's Grid Improvement Plan in his direct testimony. In Oliver Exhibit 4, a listing of specific Grid Improvement Plan programs is provided, including thirteen Distribution programs, three Transmission programs, and five Enterprise programs. The Company is requesting deferral of the North Carolina retail share of the following types of costs for these identified programs:

depreciation of capital investments, return on capital investments (net of accumulated depreciation) at the Company's weighted average cost of capital, O&M expense related to the installation of equipment, property tax related to the capital investments, and a return of the balance of costs deferred at the Company's weighted average cost of capital.

Witness Oliver's direct testimony provides estimated amounts to be spent as part of the Grid Improvement Plan in the state of North Carolina. However, for purposes of determining amounts to be deferred for future cost recovery from North Carolina retail customers, consideration is given to the nature of the expenditures (*i.e.,* whether the expenditures are related to improvement of the distribution system, the transmission system, or communications systems). Distribution expenditures made to improve North Carolina distribution infrastructure would be fully assigned to North Carolina retail customers. However, expenditures made to improve transmission infrastructure benefits all retail and wholesale customers, thus an appropriate share would be allocated to North Carolina retail customers. Expenditures made to improve communications systems would similarly be allocated among both retail and wholesale customers.

Q. WHAT IS THE BASIS FOR THE COMPANY'S REQUEST FOR A DEFERRAL?

A. The request meets the Commission's traditional test for deferral. As described by Witness Oliver, the expenditures to be made under the Grid Improvement Plan are not simple, regularly occurring, inconsequential investments, but rather, are major non-routine investments, that produce substantial customer benefits. Further, absent deferral the Company will experience a significant adverse earnings impact. The earnings degradation is expected to grow to over 100 basis points by 2022, the third year of the plan. These effects are material to the Company's financial standing and could adversely impact the Company's financial strength and flexibility, impairing reliable access to capital on reasonable terms. As noted by Witness Newlin, the Company's capital requirements for the next three years are projected to be approximately $8.1 billon.

Q. ARE THERE ADDITIONAL REASONS WHY THE COMMISSION SHOULD AUTHORIZE DEFERRAL OF THESE COSTS?

A. Yes. The NCUC has consistently demonstrated that deferral is not a rigid concept, but can be flexibly applied to ensure that the Commission's fundamental mandate of ensuring that rates are just and reasonable, set in a manner that balances the interests of the Company and its customers.

The Commission noted in its *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction* in DE Carolinas' 2017 rate case in Docket No. E-7, Sub 1146 ("E-7, Sub 1146 Order") that regulatory lag is always present in an integrated, investor-owned utility market such as North Carolina. As the Commission is aware, this is particularly so in a jurisdiction (like North Carolina) that uses a historical test year to set rates. The Commission specifically noted that while grid improvement costs identified in the totality of that case were substantial, on an individual project basis the projects were by and large of insufficient length to qualify for CWIP or AFUDC prior to placement into service. The Commission noted that as a result, the Company risked erosion of its ability to earn its authorized return due to regulatory lag. However, as the magnitude of that erosion had not been quantified, the Commission declined to authorize a deferral in that case. Instead, the Commission noted that it would be willing to entertain a future deferral request outside the test year "were the Company to demonstrate that the costs can be properly classified as … grid modernization [and not customary spend]." (E-7, Sub 1146 Order, p. 148.) The Commission indicated that a list of projects arising from a collaborative stakeholder process would aid it in the examination of a deferral request. Witness Oliver's testimony shows that the projects for which the Company seeks deferral do indeed arise from a robust stakeholder process. And, the Commission noted further, it could authorize deferral of "demonstrated" grid modernization costs incurred prior to the test year with "reliance on leniency in imposing the 'extraordinary expenditure' test." (E-7, Sub 1146 Order, p. 149.)

Another example of the flexibility with which the Commission may approach deferral requests is the recently decided DE Carolinas Northbrook Hydro matter (Docket No. E-7, Sub 1181). There, the Commission looked to the benefits accruing to the Company's customers due to the sale of some of the Company's hydroelectric generation assets; found that those benefits were substantial; and allowed the Company to defer the loss experienced on the sale considering the relatively small cost that customers would have to bear in the future due to the deferral. As set out in the testimony of Company Witness Oliver, the benefits to customers of the Company's grid modernization program are significant.

VII. PETITION FOR ACCOUNTING ORDERS TO DEFER HURRICANE DORIAN INCREMENTAL STORM COSTS, THE NET BOOK VALUE OF EARLY RETIRED ROXBORO WASTEWATER TREATMENT PLANT AND COSTS RELATED TO ASHEVILLE COMBINED CYCLE PLANT

Q. WHAT IS THE COMPANY'S PROPOSAL REGARDING RECOVERY OF COSTS RELATED TO 2019 HURRICANE DORIAN?

A. DE Progress respectfully requests that the Commission issue an accounting order authorizing the Company to defer in a regulatory asset account the incremental costs, including incremental O&M expenses, depreciation expense and carrying costs at its weighted average cost of capital on the incremental capital cost as well as the carrying costs on the deferred costs incurred in connection with Hurricane Dorian. The Company proposes to begin a 15-year amortization of the costs when proposed new base rates become effective, and to include a return on the deferred balance. Major storm costs from 2018 Hurricanes Florence and Michael and Winter Storm Diego are the subject of the Company's Petition for An Accounting Order filed in Docket No. E-2, Sub 1193, pending before the Commission, and for which the Company is requesting consolidation with this proceeding. The Company requests an accounting order to defer 2019's Hurricane Dorian incremental storm costs like what was requested in Docket No. E-2, Sub 1193 noted above.

Q. CAN YOU PLEASE DESCRIBE HURRICANE DORIAN?

A. Hurricane Dorian reached the Carolinas as a Category 2 hurricane on September 6, 2019, bringing high winds, tornadoes and heavy rain with maximum sustained winds of 90 mph. Dorian moved northeast along the North Carolina coast, just south of the Crystal Coast, clipping Cape Lookout and eventually making landfall at Cape Hatteras. The Company restored service in record time, activating a robust number of line crew, support, and other personnel. Witness Jackson describes these restoration efforts in more detail.

Q. WHAT ARE THE FINANCIAL IMPLICATIONS RELATED TO HURRICANE DORIAN?

A. As noted on Jackson Exhibit 2, page 4, incremental O&M storm costs incurred by DE Progress due to Hurricane Dorian were approximately $204.4 million for North Carolina. Total capital costs for Hurricane Dorian were approximately $19.7 million. These amounts are estimated at this point and will be accumulated from the actual invoices for line workers, tree professionals, materials, and staging and logistics received from the various vendors. Invoices will continue to be received, validated and paid over the next several months. The total incremental cost above is the Company's best estimate at this point and will be trued-up with final amounts expected to be known by mid-2020.

Similar to its request in Docket No. E-2, Sub 1193, the Company is requesting to defer the incremental O&M expenses, less approximately $26 million in “normal storm range expense.”[1] Also, similar to its request in Docket No. E-2, Sub 1193 and for the same reasons described in that request, the Company is requesting that the Commission deviate from its prior practice related to storm deferrals and allow the amortization to begin with new rates effective in this rate case, and allow deferral of capital costs, including depreciation expense and carrying costs at its weighted average cost of capital on the incremental capital costs as well as the deferred balance. Without approval of this deferral request, the Company will face significant earnings degradation of approximately 253 basis points. If the Commission were to approve the deferral, but require the amortization to begin in the month of the storm and deny deferral of capital costs as it did for Hurricane Matthew, the Company will face significant earnings degradation of approximately 68 basis points. Approval of the Company’s request will benefit the Company and its customers by helping to ensure investors’ confidence in DE Progress, and help assure access to needed capital on reasonable terms and equitable treatment as to deferred costs and revenues.

[1] In the Sub 1142 Order, the Commission noted that “deferrals of storm costs are limited to those costs that are beyond the normal range of fluctuation of storm costs from year” to year. The Commission determined that amount to be $27 million on a North Carolina retail basis, less the North Carolina allocable share ($1 million) in other storm costs in 2019 (as of September 2019), for a remaining total normal storm range amount of $26 million

Additionally, the magnitude of the storm costs that the Company has incurred over the last two years – a total of $719.6 million of incremental O&M and $114.5 of incremental capital for Hurricanes Florence, Michael and Dorian and Winter Storm Diego – warrant different treatment than the Commission has previously provided related to storms. Refer to Witness Jackson Exhibits 1 and 2 for more detail.

Q. WHAT IS THE COMPANY'S PROPOSAL REGARDING RECOVERY OF COSTS RELATED TO THE ROXBORO WASTEWATER TREATMENT PLANT?

A. Roxboro Wastewater Treatment plant is expected to commence early retirement in mid-to-late 2020. Since 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 at the level presented in the proposed depreciation study, until rates can be adjusted in the Company's next general base rate case. The Company also requests permission to defer to this regulatory asset any costs related to obsolete inventory, net of salvage, at the time of retirement.

Q. WHAT IS THE COMPANY'S PROPOSAL REGARDING RECOVERY OF COSTS RELATED TO THE NEW ASHEVILLE COMBINED CYCLE PLANT?

A. The new Asheville Combined Cycle plant is expected to go into service in December 2019. Witness Turner describes this new generation asset in more detail in her direct testimony. DE Progress requests that the Commission issue an accounting order authorizing the Company to defer in a regulatory asset account the incremental O&M expenses, depreciation expense, property taxes and return associated with the new Asheville Combined Cycle plant from the date the plant is estimated to go into operation, December 2019, until new rates are effective in September 2020. Without approval of this deferral request, the Company will face earnings degradation of approximately 80 basis points. Approval of this request would be consistent with prior commission practice regarding significant new generation plants and would better align costs with revenues.

VIII. CONCLUSION

Q. IN YOUR VIEW, ARE THE OPERATING EXPENSES AND RATE BASE CALCULATED BY DE PROGRESS IN THIS PROCEEDING IN ACCORDANCE WITH THE PROVISIONS OF N.C. GEN. STAT. § 62-133 AND NCUC RULE R1-17?

A. Yes. They are. The Company generally experienced a level of ordinary business expenses and rate base that was reasonable and necessary to provide safe and reliable electric service to its customers for the twelve-month period ended December 31, 2018. To meet the requirements of N.C. Gen. Stat. § 62-133 and this Commission's Rule R1-17, the actual operating expenses and rate base levels for the Test Period were adjusted for known and measurable changes as described in Section IV of my testimony and in the testimonies of Witnesses McGee and Pirro.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of	)	
	)	**SUPPLEMENTAL**
Application of Duke Energy Progress,	)	**DIRECT TESTIMONY OF**
LLC For Adjustment of Rates and	)	**KIM H. SMITH FOR**
Charges Applicable to Electric Service in	)	**DUKE ENERGY PROGRESS,**
North Carolina	)	**LLC**

I. INTRODUCTION AND PURPOSE

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

A. My name is Kim H. Smith, and my business address is 550 South Tryon Street, Charlotte, North Carolina. I am a Director of Rates & Regulatory Planning, employed by Duke Energy Carolinas, LLC, ("DE Carolinas"), testifying on behalf of Duke Energy Progress, LLC ("DE Progress" or the "Company").

Q. ARE YOU THE SAME KIM H. SMITH WHOSE DIRECT TESTIMONY AND EXHIBITS WERE FILED IN THIS DOCKET?

A. Yes. I filed Direct Testimony and Exhibits on October 30, 2019.

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my supplemental direct testimony is to present additional adjustments to the test period rate base, operating revenue, operating expense and operating income as shown on Smith Supplemental Exhibit 1. I noted in my previously filed testimony that the Company planned to make updates to certain test period adjustments during the proceeding. I will discuss each adjustment below. I also update the Excess Deferred Income Tax Rider ("EDIT") calculation, shown on Smith Supplemental Exhibit 4, to reflect known changes to the EDIT balances and amortization amounts as of February 2020. Finally, I explain actions taken by the

Company to review its test period electric operating expenses before filing its case.

The table below shows all pro forma adjustments to test period amounts. The particular adjustments that have been updated or revised are shown in bold text.

ADJUSTMENTS TO OPERATING REVENUES AND EXPENSES		
Line No.	**Adjustment Title**	**Witness**
1	**Annualize retail revenues for current rates**	**Pirro**
2	**Update fuel costs to proposed rate**	**McGee**
3	**Normalize for weather**	**Pirro**
4	**Annualize revenues for customer growth**	**Pirro**
5	Eliminate unbilled revenues	Smith
6	**Adjust for costs recovered through non-fuel riders**	**Smith**
7	Adjust O&M for executive compensation	Smith
8	**Annualize depreciation on year end plant balances**	**Smith**
9	Annualize property taxes on year end plant balances	Smith
10	**Adjust for post-test year additions to plant in service**	**Smith**
11	**Amortize deferred environmental costs**	**Smith**
12	**Annualize O&M non-labor expenses**	**Smith**
13	**Normalize O&M labor expenses**	**Smith**
14	**Update benefits costs**	**Smith**
15	**Levelize nuclear refueling outage costs**	**Smith**
16	**Amortize rate case costs**	**Smith**
17	Adjust aviation expenses	Smith
18	Adjust for approved regulatory assets and liabilities	Smith
19	**Adjust for merger related costs**	**Smith**
20	**Amortize severance costs**	**Smith**
21	Adjust for NC income tax rate change	Smith

ADJUSTMENTS TO OPERATING REVENUES AND EXPENSES		
Line No.	**Adjustment Title**	**Witness**
22	**Synchronize interest expense with end of period rate base**	**Smith**
23	**Adjust cash working capital for present revenue annualized and proposed revenue**	**Smith**
24	**Adjust coal inventory**	**Smith**
25	**Adjust credit card fees**	**Smith**
26	**Adjust for new depreciation rates**	**Smith**
27	Adjust vegetation management expenses	Smith
28	Adjust reserve for end of life nuclear costs	Smith
29	**Update deferred balance and amortize storm costs**	**Smith**
30	Adjust other revenue	Pirro
31	Adjust for change in NCUC regulatory fee	Smith
32	**Reflect retirement of Asheville Steam Generating Plant**	**Smith**
33	**Adjust for CertainTeed payment obligation**	**Smith**
34	**Amortize deferred balance of Asheville Combined Cycle Plant**	**Smith**
35	Adjust purchased power	Smith

Q. WERE YOUR SUPPLEMENTAL EXHIBITS PREPARED AT YOUR DIRECTION AND UNDER YOUR DIRECT SUPERVISION?

A. Yes, they were.

II. UPDATES TO THE COMPANY'S TEST PERIOD OPERATING REVENUE, EXPENSES AND RATE BASE

Q. PLEASE DESCRIBE SMITH SUPPLEMENTAL EXHIBIT 1.

A. Smith Supplemental Exhibit 1 presents the impact of additional adjustments to test period operating income and rate base that the

Company is supporting at this time. Page 1 of the Exhibit summarizes the adjustments and the details for each adjustment are presented on the subsequent pages.

Q. WAS SMITH SUPPLEMENTAL EXHIBIT 1 PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

A. Yes.

Q. PLEASE EXPLAIN THE ADJUSTMENTS THAT ARE PRESENTED IN SMITH SUPPLEMENTAL EXHIBIT 1.

A. **Line 1 - Annualize retail revenues for current rates**

Witness Pirro's supplemental direct testimony describes this adjustment.

Line 2 - Update fuel costs to approved rate

This adjustment was updated to include revisions to fuel rates approved under Docket No. E-2, Sub 1204. Also, this adjustment has been revised to reflect removal of catalyst depreciation from fuel clause recovery. In its initial filing, DE Progress proposed to include this cost as a component of fuel rates. After discussion with the Public Staff, the Company has concluded that recovery of this cost in base rates is the most reasonable cost recovery approach.

Line 3 - Normalize for weather

Witness Pirro's supplemental direct testimony describes this adjustment.

Line 4 - Annualize revenues for customer growth

Witness Pirro's supplemental direct testimony describes this adjustment.

Line 6 – Eliminate costs recovered through non-fuel riders

This adjustment has been updated to remove additional O&M identified for Competitive Procurement of Renewable Energy ("CPRE") during supplemental updates.

Line 8 – Annualize depreciation on year-end plant balances

This adjustment is revised to include catalyst depreciation as a component of the adjustment. In its initial filing, DE Progress proposed recovery of this cost through fuel rates rather than base rates. After discussion with the Public Staff, the Company has concluded that recovery of this cost in base rates is the most reasonable cost recovery approach.

Line 10 - Adjust for post test year additions to plant in service

This adjustment has been updated to replace estimated data with actual amounts through February 2020. In addition, this item is revised to eliminate retirements of meters that have been previously approved for deferral as a regulatory asset, since the deferred amount continues to be amortized. Also, the remaining portion of Asheville CC that is expected to be placed in service in March 2020 was added as an addition to plant in service.

Line 11 - Amortize deferred environmental costs

This adjustment has been updated to replace estimated data with actual amounts through February 2020. In addition, the adjustment has been revised to incorporate accumulated deferred income tax benefits related to bonus tax depreciation for qualifying non-ARO projects.

Line 12 - Annualize non-labor O&M expenses

This adjustment has been updated to reflect the impact of revisions to Adjustments 6, 20 and 33.

Line 13 - Normalize O&M labor expenses

This adjustment has been updated to reflect actual salary data as of February 2020.

Line 14 – Update benefits costs

This adjustment has been updated to reflect projected 2020 costs based on the Company's most recent actuarial study.

Line 15 – Levelize nuclear refueling outage costs

This adjustment has been updated to reflect the last known and measurable outage deferral amortization expense as of February 2020.

Line 16 - Amortize rate case costs

This adjustment has been updated to reflect the actual costs incurred through February 2020.

Line 19 - Adjust for merger related costs

This adjustment has been updated to reflect the actual costs incurred through February 2020.

Line 20 – Amortize severance costs

This adjustment has been updated to reflect actual amounts through February 2020.

Line 22 - Synchronize interest expense with end of period rate base

This adjustment to income tax expense has been updated to reflect the impacts resulting from other updated and revised pro forma adjustments affecting rate base and the associated annualized interest expense.

Line 23 - Adjust cash working capital for present revenue annualized and proposed revenue

This adjustment uses amounts from other test period adjustments. It has been updated to reflect the changes made to other adjustments. In addition, the calculations have been updated to reflect revisions to the lead-lag study as discussed in the supplemental direct testimony and exhibits of Witness Angers.

Line 24 – Adjust coal inventory

This adjustment has been updated to reflect the projected average delivered coal costs per ton from Docket No. E-2, Sub 1204, to adjust the fixed transportation costs and to reflect retirement of the Asheville coal units in January 2020.

Line 25 - Adjust for credit card fees

This adjustment has been updated to reflect the actual number of credit card transactions through February 2020.

Line 26 - Adjust for new depreciation rates

This adjustment is revised to include catalyst depreciation as a component of the adjustment. In its initial filing, DE Progress proposed recovery of this cost through fuel rates rather than base rates. After discussion with the Public Staff, the Company has concluded that recovery of this cost in base rates is the most reasonable cost recovery approach.

Line 29 - Update deferred balance and amortize storm costs

This adjustment has been updated to reflect actual storms costs and current depreciation rates for use in the computation of deferred depreciation expense. The pro forma was also adjusted to correct some of the allocation factors used in the calculation.

Line 32 - Reflect retirement of Asheville Steam Generating Plant

This adjustment has been updated to reflect the actual regulatory asset balance established after the retirement of the Asheville Steam Generating plant in January 2020. The regulatory asset balance was estimated in the Company's October 30, 2019 filing. In addition, as a result of updating Adjustment 10 to reflect actual amounts as of February 2020, the removal of the retired Asheville assets from electric plant and accumulated depreciation is accomplished in Adjustment 10 rather than this adjustment.

Line 33 - Adjust for CertainTeed payment obligation

This adjustment has been updated to remove the test period and projected O&M costs associated with the Company's CertainTeed settlement, as the Commission ordered those dollars to be recovered through the Fuel Clause in Docket No. E-2, Sub 1204.

Line 34 – Amortize deferred balance Asheville Combined Cycle

This adjustment has been updated to reflect the estimated deferred costs and associated regulatory asset established for the Asheville Combined

Cycle plant to account for costs between the in-service dates of the plant and the new rates effective date. At the time of the application the plant was expected to be in service in late 2019. As of February 29, 2020 Units 5, 6 and 7 placed in service. Unit 8 is expected to be in service before the start of the hearing on May 4, 2020.

Line 35 – Adjust for cash working capital for lead-lag revision - NEW

This adjustment has been added to revise the test period cash working capital component of electric rate base. The revision is necessary to reflect the revisions to the lead-lag study as described in the supplemental direct testimony and exhibits of Witness Angers.

Q. DOES SMITH SUPPLEMENTAL EXHIBIT 1 REFLECT ANY CHANGE IN THE REVENUE REQUIREMENT SOUGHT BY THE COMPANY IN THIS PROCEEDING?

A. Although Smith Supplemental Exhibit 1 does show an increase in the proposed amount of electric operating revenues, the Company is not requesting a change in its originally proposed revenue increase at this time. For this reason, the exhibit is marked for informational purposes only.

Q. IN YOUR OPINION, DO THESE ACCOUNTING AND PRO FORMA ADJUSTMENTS REFLECT KNOWN AND MEASURABLE CHANGES TO THE COMPANY'S TEST PERIOD OPERATING EXPENSES, REVENUES, AND RATE BASE?

A. Yes.

III. EDIT RIDER

Q. PLEASE EXPLAIN THE CHANGES REFLECTED IN SMITH SUPPLEMENTAL EXHIBIT 4.

A. Smith Supplemental Exhibit 4 includes revisions that reflect completion of Duke Energy's 2018 federal income tax return. The annual amortization percentage for Protected EDIT has been updated to an actual amount that aligns with the most recently filed federal income tax return, which is the Company's best estimate for the following year's protected EDIT amortization. This update is necessary to comply with federal tax normalization rules and was referenced in my Direct Testimony. Additionally, the Federal Unprotected PP&E related EDIT and NC EDIT components of the rider were updated, to reflect minor revisions to the EDIT amounts.

IV. OTHER

Q. BEFORE FILING ITS CASE, DID DE PROGRESS REVIEW ITS OPERATING EXPENSES AND REMOVE COSTS THAT IT DEEMED WERE NOT APPROPRIATE TO RECOVER FROM ITS ELECTRIC RETAIL CUSTOMERS?

A. Yes. While the Company's system of internal accounting controls and audits are in place to provide reasonable assurance that amounts recorded on the books and records of the Company are accurate and proper, the Company has experienced occasions when certain expenses have been improperly charged due to human error. To ensure that the proposed revenue requirement in the case does not reflect any amounts of electric expenses that are inaccurate, the Company took additional steps to eliminate the impact of potential mischarges due to human error. Specifically, prior to filing this rate case, the Company took preventive measures to review underlying cost data in particular accounts where errors could likely occur. The Company used a combination of data analytics to electronically scan source data and manual reviews of detail transactions to identify expenses that it deemed were not appropriate for cost recovery.

Q. DID DE PROGRESS TAKE ADDITIONAL PRECAUTIONS TO ENSURE MISCHARGES THAT MAY HAVE BEEN MISSED IN ITS REVIEW WERE STILL NOT INCLUDED FOR RECOVERY FROM ITS ELECTRIC RETAIL CUSTOMERS?

A. Yes. As an additional precaution, DE Progress elected to remove an additional $0.2 million of system electric operating expenses from allocation to North Carolina retail customers in case any other potential mischarges were discovered during the course of this proceeding. Any such mischarges that are discovered would be deducted against this amount, and, if any amount of this $0.2M remains after any further mischarges are netted against it, the remaining balance will continue to be excluded from recovery for the benefit of customers.

Q. PLEASE DESCRIBE THE STEPS THE COMPANY TOOK TO REMOVE THE ADDITIONAL $0.2 MILLION IN ELECTRIC OPERATING EXPENSES FROM THE COMPANY'S REVENUE REQUIREMENT IN THIS CASE.

A. As part of the Company's Cost of Service study, electric operating expenses and electric rate base for North Carolina retail jurisdiction are determined by directly assigning or allocating DE Progress system amounts based on cost causation principles. It is normal in a Cost of Service study to evaluate DE Progress system costs for assignment or allocation to either North Carolina retail customers, South Carolina retail customers, to wholesale customers or to no customers (i.e. "other"). This practice is common, since there are certain electric operating expenses that are appropriate to assign to one particular rate jurisdiction, or to appropriately exclude from recovery from electric customers. However, this is the first time that the Company has used this process as a mechanism to help ensure that the costs assigned to a particular jurisdiction do not inadvertently reflect any improper charges due to human error.

Q. PLEASE FURTHER DESCRIBE WHY THE COMPANY ELECTED TO TAKE THE ADDITIONAL PRECAUTION OF REMOVING $0.2 MILLION OF ELECTRIC OPERATING EXPENSES FROM ITS CASE.

A. The Company's goal in this instance was to reduce the potential for supplemental changes to its requested revenue increase. Should the Public Staff or another party, in the course of their audit of expenses, identify an amount of system cost that they and the Company agree were improperly included in North Carolina retail electric expenses due to human error, there would be no need for another party to propose an adjustment, so long as the amount of error does not exceed the additional $0.2 million as described above. If, however, mischarges are found that exceed the $0.2 million, the Company would make a supplemental adjustment to its filing to reflect further reduction of electric expenses assigned or allocable to North Carolina retail.

V. <u>CONCLUSION</u>

Q. DOES THIS CONCLUDE YOUR PRE-FILED SUPPLEMENTAL DIRECT TESTIMONY?

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of:	)	
	)	**REBUTTAL TESTIMONY OF**
Application of Duke Energy Progress, LLC	)	**KIM H. SMITH**
For Adjustment of Rates and Charges	)	**FOR DUKE ENERGY**
Applicable to Electric Service in North	)	**PROGRESS, LLC**
Carolina	)	

I. INTRODUCTION AND PURPOSE

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

A. My name is Kim H. Smith, and my business address is 550 South Tryon Street, Charlotte, North Carolina. I am a Director of Rates & Regulatory Planning, employed by Duke Energy Carolinas, LLC ("DE Carolinas"), testifying on behalf of Duke Energy Progress, LLC ("DE Progress" or the "Company").

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS DOCKET?

A. Yes. I filed direct testimony and exhibits on October 30, 2019. I also filed supplemental direct testimony and exhibits on March 13, 2020.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my rebuttal testimony is to: (1) respond to certain accounting and ratemaking adjustments proposed by the Public Staff in its direct and supplemental testimony; and (2) respond to certain issues raised in intervenor testimony, including the recovery of coal ash compliance costs, the Company's proposed EDIT Rider, and the Company's request for a deferral for Grid Improvement Plan costs. I also provide revisions to my supplemental direct testimony filed on March 13, 2020.

Q. DOES YOUR TESTIMONY INCLUDE ANY EXHIBITS?

A. Yes. I have included five exhibits. Smith Rebuttal Exhibit 1 shows adjustments to the revenue requirements for the individual adjustments discussed later in my testimony. Smith Rebuttal Exhibit 2 summarizes the total revenue adjustments proposed in this proceeding, including the proposed increase in base rates and the net reduction in revenues reflected in existing and proposed riders. Smith Rebuttal Exhibit 3 reconciles the revenue requirement as presented in my supplemental testimony to the revenue requirement presented in this rebuttal testimony. Smith Rebuttal Exhibit 4 is an updated proposed EDIT-2 rider to reflect a change in the debt cost rate as discussed later in my testimony. Smith Rebuttal Exhibit 5 is DE Carolinas and DE Progress' Joint Brief filed before the Supreme Court of North Carolina on September 25, 2019 in response to appeals in Docket Nos. E-7, Sub 1146 and E-2, Sub 1142.

Q. WERE THESE EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION AND SUPERVISION?

A. Smith Rebuttal Exhibit 1 through 4 were prepared under my direction and supervision. Smith Rebuttal Exhibit 5 is a publicly available filing made by the Company in an ongoing proceeding. While I am not a lawyer and do not provide legal opinions, I have reviewed and support the portions of the brief that respond to the Public Staff's position that I describe below.

II. RESPONSE TO PUBLIC STAFF ACCOUNTING ADJUSTMENTS

Adjustments Not Opposed or Partially Opposed

Q. ARE THERE ANY ADJUSTMENTS RECOMMENDED BY THE PUBLIC STAFF THAT THE COMPANY DOES NOT OPPOSE OR PARTIALLY OPPOSES?

A. Yes. There are several adjustments by the Public Staff, shown on Dorgan Exhibit 1, Schedule 1, that the Company either does not oppose or opposes in part. In addition to the reasons set forth below, the Company opposes any adjustment resulting from the Public Staff's use of a 50/50 debt and equity capital structure, a 9.00% return on equity ("ROE"), and/or Summer/Winter Peak and Average ("SWPA") allocation factors.

Line 6 – Change in debt cost rate from 4.155% to 4.110%

The Company does not oppose this adjustment.

Line 9 – Update plant and accumulated depreciation to February 29, 2020

This Public Staff adjustment aligns in concept with portions of the Company's supplemental direct testimony and exhibits filed March 13, 2020, which include updated amounts through February 29, 2020. However, the Company does not agree with the Public Staff's proposed depreciation rates, which makes the Company unable to agree with the dollar amount of the adjustment proposed by witness Dorgan. Also, the Company does not agree with witness Dorgan's statement on page 12 of his direct testimony, wherein he argues that retirements are not reflected in the amount of plant used to compute depreciation expense, and, therefore, depreciation expense is overstated. In both its initial filing on October 30, 2019 and its supplemental filing on March 13, 2020, the Company included retirements in the amount of plant used to compute depreciation expense; therefore, depreciation expense was not overstated. Finally, the Company does not agree with the amount of the adjustment because it needs to be updated for the actual costs of the Asheville Combined Cycle Unit 8, which went into service on April 5, 2020. I describe this update to the adjustment later in my testimony.

Line 11 – Adjust credit card fees

The Company partially agrees with this adjustment. The Public Staff made an adjustment to remove operating and maintenance ("O&M") expenses associated with the increase in fee-free program transactions from 2018 to 2019. The Company accepts the concept of the Public Staff's adjustment but has updated the calculation to reflect avoided transaction costs related to payment by check. This change is reflected on Smith Rebuttal Exhibit 1.

Line 16 – Adjust salaries and wages expense

This adjustment aligns with the Company's supplemental direct testimony and exhibits filed March 13, 2020, which include updated amounts through February 29, 2020.

Line 17 – Adjust outside services

The Company partially agrees with the items identified by the Public Staff related to certain outside services costs. Certain costs the Public Staff identified the Company agrees should be excluded; however, the Company believes these costs have already been removed from the revenue requirement. The amounts are mischarges to the outside services account due to human error. As explained in my supplemental direct testimony filed March 13, 2020, the Company proactively removed $0.2 million of system electric operating expenses from allocation to North Carolina retail electric expenses to cover any mischarges identified during the course of the rate case proceeding. As such, the Company believes no additional adjustment to the proposed revenue increase is required for these costs. In addition, the Company disagrees with the Public Staff's removal of outside services charges of $42,000 for missing invoices. The support for those charges, including invoices, was provided in response to Public Staff Data Request 105. It is the Company's understanding that the Public Staff agrees this adjustment was an error. The Company also disagrees with the description on Line 1 of Dorgan Exhibit and Supplemental Exhibit 1 Schedule 3-1(k), "Remove items related to coal ash litigation." The costs that comprise this line item do not include items related to coal ash litigation.

Line 26 – Adjust Asheville CC Plant in Service

The Company partially agrees with this adjustment. The Company accepts the Public Staff's methodology on calculating the annualized O&M for the Asheville plant. The Company opposes the concept of the Public Staff's adjustment to use the annuity factor method to calculate amortization expense, removing the deferral and ADIT balances from rate base. The Company also disagrees with the dollar amount of the adjustment for the reasons set forth below.

Line 30 – Adjust coal inventory

This adjustment aligns with the Company's supplemental direct testimony and exhibits filed March 13, 2020.

Line 32 – Adjust charitable contributions, corporate sponsorships, and corporate donations

The Company partially agrees with this adjustment. The Company disagrees with the adjustment for the Chamber-related items for the reasons set forth in the rebuttal testimony of Company witness Angers. The Company agrees with excluding the remaining items, which total approximately $22,000. These items were inadvertently included in cost of service due to human error. As explained in my supplemental direct testimony filed March 13, 2020 and described herein, the Company proactively removed $0.2 million of system electric operating expenses from allocation to North Carolina retail electric expenses to cover any mischarges identified during the course of the rate case proceeding. As such, the Company believes no additional adjustment to the proposed revenue increase is required.

Line 35 – Adjust inflation to February 29, 2020

The Company does not oppose this adjustment to update inflation impacts as it is consistent with updates to other post test year expenses. However, since the Company does not agree with the Public Staff's other proposed adjustments that affect test year O&M amounts, the Company cannot agree with the total dollar amounts of the Staff's inflation adjustment. The Company's revisions to update non-labor O&M amounts to reflect inflation through February 29, 2020, are shown on Smith Rebuttal Exhibit 1.

Adjustments Opposed

Q. ARE THERE ANY ADJUSTMENTS RECOMMENDED BY THE PUBLIC STAFF THAT THE COMPANY OPPOSES?

A. Yes. There are several adjustments by Public Staff, shown on Dorgan Exhibit 1, Schedule 1, that the Company opposes. In addition to the reasons set forth below, the Company opposes any adjustment resulting from the Public Staff's use of a 50/50 debt and equity capital structure, a 9.00% ROE, and/or SWPA allocation factors.

Line 12 – Remove Unprotected Federal EDIT, State EDIT, and deferred Federal EDIT from base rates for treatment as a rider, and Line 13 - Adjust for flowback of Protected Federal EDIT due to Tax Cuts and Jobs Act

The Company does not oppose rider treatment for excess deferred income taxes ("EDIT") and has proposed refund through a rider in its initial filing. However, the Company does oppose the specific rider treatment as proposed by the Public Staff. The Company's objections are described later in my testimony.

Line 14 – Adjust aviation expenses

The Company opposes this adjustment. In its initial and supplemental filings, the Company removed 50% of the Company's O&M costs related to corporate aviation to account for flights that may not be related to provision of electric service. For the test period, DE Progress was allocated approximately 23% of the corporate amount of aviation expense. All of the expenses of the corporate aircraft have been allocated in accordance with the Company's filed cost allocation manual. The Company's proposal to remove 50% of this amount results in inclusion of about 11.5% of corporate aviation expenses in the Company's adjusted test period cost. The Public Staff proposal would reduce the amount of aviation expenses to 10% of the corporate amount. The Company does not believe witness Dorgan has provided sufficient support that the appropriate amount of aviation expenses to be included in DE Progress electric rates should be based on 10% of corporate aviation expenses. The Company's proposal in this case is based on its settlement position in DE Progress's 2017 rate case (Docket No. E-2, Sub 1142).[1] In that case, the Public Staff and the Company agreed in partial settlement to remove 50% of the corporate aviation expenses allocated to DE Progress, which resulted in inclusion of 12% of corporate aviation expenses in the Company's rates.

Line 18 – Adjust rate case expense

The Company opposes this adjustment. Witness Dorgan's testimony states that the Public Staff made the adjustment to reflect a normalization of the costs associated with the filing of a rate case, based on a historical average of the number of years between rate case filings. The average cost of the last three

[1] Hereinafter, the "2017 DE Progress Rate Case."

rate cases, adjusted for inflation, is approximately $3.8 million and the average time between rate cases since the case filed in 2013 has been 42 months. Therefore, had the Public Staff calculated the normalization of costs associated with the filing of a rate case based on the historical average costs and number of years between rate case filings, the amortization amount would have been approximately $1.1 million, which is higher than the Company's proposed amortization amount. Rather than normalizing, the actual adjustment the Public Staff made to working capital was only to remove all post-test year expenses from the regulatory asset balance in rate base. The Company contends that the post-test year amounts that the Public Staff has removed are known and measurable costs incurred, and, therefore, the balance in rate base should *include* these amounts. It is appropriate to include rate case expenses in rate base because they are incremental costs that will have been incurred and funded by investors prior to new rates becoming effective. To fully recover the cost of those expenses, the regulatory asset needs to be reflected in rate base. The Company has reduced the regulatory asset by one year's worth of amortization expense as was also done in similar proformas, such as Company adjustment #10 – Adjust for post-test year additions to plant in service.

Line 19 – Adjust to normalize storm costs

The Company opposes this adjustment to normalize test period storm costs. In its comments in Docket Nos. E-2, Sub 1131 E-2, Sub 1193, and E-7, Sub 1187, the Public Staff stated that it considered the Company's use of a normalization adjustment in its prior rate cases as a possible basis to oppose a deferral request in general. As a result, DE Progress has not proposed a normalization adjustment for storm expense. The Company will consider an adjustment should the Public Staff's position change.

Line 20 – Adjust to remove storm deferral

The Company disagrees with removal of the storm cost deferral. The Company plans to pursue securitization of the particular storm costs as provided by recently passed legislation, North Carolina Senate Bill 559. However, as stated by Company witness De May in his rebuttal testimony, these costs must remain a part of the Company's request in this proceeding until the Commission reaches the same determination as the Company and the Public Staff that the costs were prudently incurred, and the Commission subsequently approves a financing petition. In addition, the Company notes the Public Staff's calculation uses the incorrect amount to adjust the storm assets in rate base. It is the Company's understanding that the Public Staff agrees this adjustment was an error.

Line 21 – Adjust for severance costs

The Company opposes this adjustment. Witness Dorgan attempted to adjust the severance costs to reflect a normalized level over a five-year period. However, the adjustment made was just to change the proposed amortization period from three years to five years. Had the Public Staff calculated the five-year normal level of severance expense, the North Carolina retail expense would have been

$14 million, which is greater than the Company's proposed amortization amount. Witness Dorgan then states, "With regard to the Company's request to establish a regulatory asset, the Public Staff has established a normalized level to include in rates, and, as a result, has removed the Company's requested amount from rate base." Since the Public Staff has not established a normalized level to include in rates, the Company believes it is appropriate to include the deferred severance expense in rate base. To fully recover the cost of the deferred severance expenses over a three-year period, the regulatory asset needs to be reflected in rate base. The Company has reduced the regulatory asset by one year's worth of amortization expense as was also done in similar proformas such as Company adjustment #10 – Adjust for post-test year additions to plant in service.

Line 22 –Adjust depreciation rates

The Company opposes the adjustment to include catalyst depreciation as the Company had already made this adjustment in the Company's supplemental filing on March 13, 2020. In addition, the Company opposes this adjustment for the reasons set forth in the rebuttal testimony of Company witness Spanos.

Line 27 – Adjust Asheville CC deferral

As stated above, the Company opposes the concept of the Public Staff's adjustment to use the annuity factor method to calculate amortization expense. The Company also opposes the Public Staff's calculation because the plant in service, ADIT, and inventory balances utilized by the Public Staff reflect

December 2019 amounts rather than February 2020, and the adjustment needs to be updated for the actual costs of the Asheville Combined Cycle Unit 8, which went into service on April 5, 2020. I describe this update to the adjustment later in my testimony. The Company also disagrees with the adjustment to extend the amortization period to five years rather than three years. The Public Staff argues that a five-year amortization period is consistent with the amortization period historically proposed by the Public Staff related to the deferral of costs of adding baseload plants. The Company believes that a three-year amortization period is appropriate. The Company's proposal for an amortization period is based on elements of its current case, rather than looking back at previous rate cases involving new baseload plants. The Company's current case includes several regulatory amortizations in addition to Asheville CC deferred costs, including costs associated with the retired Asheville coal plant, deferred environmental costs, and excess deferred tax liability. Many of these deferrals involve larger dollar amounts and longer amortization periods. Since the Asheville CC deferred cost amounts are much smaller, the Company believes a short amortization period is appropriate.

Line 28 – Adjust W. Asheville Vanderbilt 115kV Project

The Company opposes this adjustment as the Company had already made an adjustment in post-test year additions for this project in Smith Supplemental Exhibit 1, filed March 13, 2020.

Line 37 – Adjust to remove CertainTeed payment obligation

The Company opposes this adjustment as the amounts related to the CertainTeed payment had already been removed as of February 29, 2020, in the Company's supplemental filing on March 13, 2020. It is our understanding that the Public Staff agrees this adjustment was in error.

Line 38 – Adjust cash working capital under present rates, and Line 39 – Adjust working capital under proposed rates

Since the Company does not agree with all the Public Staff's proposed adjustments, to the extent the adjustments affect the working capital amounts, the Company cannot agree with the total dollar amounts of the Public Staff's two working capital adjustments. In discussions with the Public Staff, we believe the Company is now in agreement with the Public Staff on the overall calculation template for these items; however, our final numbers will still differ based on the other areas of disagreement.

Adjustments to Coal Ash Pond Closure Costs

Q. PLEASE EXPLAIN THE COMPANY'S RESPONSE TO THE PUBLIC STAFF ADJUSTMENTS REGARDING COAL ASH POND CLOSURE COSTS.

A. The Company opposes the two adjustments related to coal ash pond closure cost recovery, which are listed on lines 24 and 25 of Dorgan Exhibit 1, Schedule 1:

Line 24 - Adjust deferred environmental costs

Line 25 - Adjust deferred non-ARO environmental costs

Q. PLEASE SUMMARIZE THE FIRST ADJUSTMENT.

A. This adjustment, addressing Asset Retirement Obligation ("ARO")-related coal ash expenditures, is based on three recommendations proposed by Public Staff witness Maness on pages 17-18 of his direct testimony. Witness Maness's first recommendation relates to the disallowance of certain coal ash management expenditures as recommended by several other Public Staff witnesses. Company witness Bednarcik addresses this recommendation in her rebuttal testimony.

Witness Maness's second and third recommendations are to lengthen the amortization period for recovery of the remaining coal ash pond closure costs; and to remove the unrecovered balance from rate base, thus disallowing a return on the unamortized balance. These two recommendations accomplish his objective that these costs be shared between customers and shareholders. Witness Maness states that the five-year amortization period proposed by the Company is "simply too short" given the magnitude and nature of the costs. His specific recommendation of a 27-year amortization period, in combination with no return on the unamortized balance, results in roughly 50/50 sharing of costs between customers and shareholders.

Witness Maness identifies two general reasons why he believes this sharing is reasonable and appropriate. He explains that it is appropriate that these costs be shared because of the Company's general culpability, as well as historical precedent for regulatory treatment of costs that do not result in any new generation of electricity for customers. In addition, witness Maness cites several additional reasons the costs should be shared, including the magnitude of costs in this case as well as expected future costs, the lack of customer benefits or economic advantages related to these costs, and concerns about intergenerational inequity.

Q. WHY DOES THE COMPANY DISAGREE WITH THIS ADJUSTMENT?

A. The Public Staff's "equitable sharing" adjustment runs directly contrary to well-established ratemaking and cost recovery principles and, in particular, the basic principle that a public utility's reasonable and prudently incurred costs are recoverable in rates.[2]

The particular costs at issue with this adjustment are the costs incurred by the Company in connection with its coal ash basin closure activities from September 1, 2017 through February 29, 2020. All of these costs were incurred due to a change in the law that required the Company to manage coal ash differently than it had done in the past, and to retire long-lived assets that the Company had been using for purposes of coal ash management and storage. Because of the asset retirement requirement, the costs are accounted for in

[2] I am not a lawyer, and I do not provide legal opinions. Beginning on p. 27 of his direct testimony in this case, witness Maness refers to a lengthy legal memorandum to support the Public Staff's equitable sharing proposal, which was attached as an exhibit to witness Maness's testimony in the DE Carolinas' 2017 rate case in E-7, Sub 1146 ("2017 DE Carolinas Rate Case"). DE Carolinas and DE Progress's legal position on these issues is set out in detail in their respective post-hearing legal filings in the DE Carolinas and DE Progress 2017 Rate Cases as well as in their joint brief filed in the North Carolina Supreme Court in connection with the appeal by the Public Staff and other intervenors of the Commission's decisions in those cases. A copy of that brief is attached as Smith Rebuttal Exhibit 5 to my testimony; see in particular Section IV. The Public Staff's approach has already been rejected three times by the Commission.

AROs. Company witness Doss discusses this from an ARO accounting perspective in his rebuttal testimony.

The Public Staff's "sharing" approach does not depend on any finding of imprudence in connection with the incurrence of these costs. Instead, the Public Staff's approach consists merely of removing the unamortized balance of coal ash expenditures from rate base in addition to amortizing the balance over an arbitrary period – 27 years. This lengthy amortization period is what is necessary in order for the Public Staff to achieve its desired goal – a 50/50 split between the Company and its customers of the deferred coal ash basin closure costs sought for recovery in this case. But there are no standards, according to the Public Staff, that guide the exercise of what it deems to be the Commission's discretionary power to put "equitable" sharing into effect – that is what makes the Public Staff's proposal arbitrary.

In the 2017 DE Progress Rate Case, the Commission explained why the Public Staff's equitable sharing proposal was arbitrary:

> The Commission agrees with DEP that this adjustment is not based on an applicable standard. The Public Staff chose this number, then adjusted the mechanism to achieve that level of disallowance. The Public Staff provides insufficient justification for the 50/50 as opposed to a 60/40, or 80/20. Witness Maness indicates merely that it "was the judgment of the Public Staff … that 50 percent was a reasonable percentage." (*Id.*)

Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase, Docket No. E-2, Sub 1142 (February 23, 2018) ("2018 DE

Progress Rate Order"), at 189.[3] I believe the Commission's assessment of "sharing" was correct and see no reason for the Commission to revisit the issue in this case. If the Commission determines that the deferred costs the Company has incurred for coal ash basin closure were prudently incurred, then those costs under traditional and long-standing ratemaking and cost recovery principles are recoverable from customers.

Q. IS IT ALSO APPROPRIATE FOR THE COMMISSION TO ALLOW THE COMPANY TO RECOVER ITS FINANCING COSTS IN CONNECTION WITH COAL ASH BASIN CLOSURE?

A. Yes. The Public Staff's proposal acknowledges that financing costs during the initial period of deferral – that is, from the time the costs are incurred until they are brought into rates – should include the Company's financing costs. It is during the period over which the costs are amortized after being brought into rates that the Public Staff indicates no financing costs should be allowed. This again runs contrary to well established ratemaking and cost recovery principles.

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[3] Similarly, in the 2017 DE Carolinas Rate Case, the Commission held:

> [T]he concept is standard-less, and, therefore, from the Commission's view arbitrary for purposes of disallowing identifiable costs – there is no rationale that supports a substantially large 51% disallowance. The Public Staff chose a desirable equitable sharing ratio, then backed into the mechanism to achieve that level of disallowance, leaving the allocation subject to an arbitrary and capricious attack, particularly as it provides no explanation as to why the "equitable" split for DEP in the 2017 DEP Case was in its view 50-50, while the "equitable" split in this case is 51-49. As the Commission held in the 2017 DEP Case, the "Public Staff provides insufficient justification for the 50/50 [split] as opposed to 60/40 or 80/20 ...."

Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, Docket No. E-7, Sub 1146 (June 22, 2018) ("2018 DE Carolinas Rate Order"), at 273.

The costs at issue include the cost of money. The financing costs related to funds advanced by investors are no less costs associated with the provision of service to customers than the depreciation, O&M, or other costs of the power plants that generate electricity or the towers, poles, and lines that transmit and distribute that electricity to customers' homes and businesses. All of these costs are necessary and prudent to ensure reliable electric service. Furthermore, all of these costs were deferred by Order of the Commission in the 2017 DE Progress Rate Case and consolidated dockets. None of those costs have previously been brought into rates or paid for by customers. All of these costs have been funded by investors (both debt and equity). Because the costs are wholly financed by the Company and its investors, the Public Staff appropriately recognizes that the Company's financing costs during the deferral period are legitimately incurred and recoverable. That same principal applies during the amortization period as well.[4]

Q. PLEASE EXPLAIN.

A. The Public Staff's sharing proposal removes coal ash basin closure costs (including financing costs during the initial deferral period) from rate base in

[4] I note that Witness Maness indicates at page 51 of his direct testimony that it might be appropriate in the Company's *next* rate case to adjust the sharing percentage – and weight it more heavily in favor of customers – as some sort of compensatory mechanism in light of the Public Staff's position that financing costs during the deferral period are appropriate. While the Company is content to address this position, which runs completely contrary to well established rate making principles, in the next case (assuming the Public Staff actually asserts the position), I would point out that this merely highlights the arbitrary nature of the Public Staff's "equitable" sharing proposal. Financing costs during the deferral period are appropriate because the Company and its investors have fronted those costs. The Public Staff fully understands this. The same principle applies during the amortization period. The Public Staff, asserting that it is acting to reach an "equitable" result, persists in advocating an arbitrary process to arrive at a result that is manifestly inequitable.

order to implement its preferred "sharing" percentage. DE Carolinas witness McManeus testified to this at length in the 2017 DE Carolinas Rate Case. As she stated:

> [I]t is important to recognize that rate base represents the amount of funds supplied by investors. Such funds have been advanced for many purposes. Certainly, construction of electric plant is one such purpose, but there are others – for example, to purchase fuel inventory, to provide cash working capital, etc. Further, to accurately determine the amount of investor-supplied funds, one must consider whether any amounts that have been used for such purposes have been advanced by customers, rather than investors. In this particular case, investors have advanced funds to pay for coal ash compliance costs.

Tr. Vol. 6, p. 317 (Docket No. E-7, Sub 1146). Witness McManeus noted further that the "characteristic that makes the deferred coal ash cost a legitimate component of rate base" is the fact that the funds used to pay those costs were supplied by investors. Tr. Vol. 6, p. 318 (Docket No. E-7, Sub 1146). The Commission's Order in that case relied upon this testimony and drew the correct conclusion, both as to the deferral period as well as the amortization period:

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

> reasonable, unless the Company should be penalized due to mismanagement, for example, and the Commission would act contrary to law were it to order them.

2018 DE Carolinas Rate Order, at 290. The same logic and reasoning applies to DE Progress in this case as well. Denying the Company the opportunity to earn its allowed rate of return on prudently incurred costs results in rates that are unjust and unreasonable.

Q. WITNESS MANESS ALSO INDICATES THAT THE COMPANY'S CLASSIFICATION OF DEFERRED COAL ASH BASIN CLOSURE COSTS AS "WORKING CAPITAL" DOES NOT MEAN THAT THIS REGULATORY ASSET SHOULD BE INCLUDED IN RATE BASE. PLEASE COMMENT ON THIS POSITION.

A. Witness Maness appears again to have misinterpreted the Company's position. This was a point also covered at length in the 2017 DE Carolinas Rate Case, and the situations are identical.

It is not and never has been the Company's position that classifying the costs as "working capital" is in and of itself a justification for placing the costs in rate base. The Company's position, as described above in the quotations from witness McManeus in the 2017 DE Carolinas Rate Case, is that rate base represents investor supplied funds, and it is this characteristic that makes the deferred coal ash cost a legitimate component of rate base. While the Company does separate total investor supplied funds into distinct categories (e.g., net electric plant, working capital, prepayments, etc.), these categories still represent funds advanced by investors prior to recovery from customers, and assuming the underlying expenditures are judged reasonable and prudent by the Commission, the associated financing costs should be eligible for recovery.

Q. DID THE COMMISSION IN ITS PRIOR ORDER IN THE 2017 DE CAROLINAS RATE CASE COMMENT ON WITNESS MANESS' POSITION ON WORKING CAPITAL?

A. Yes. The Commission also stated that witness Maness had misunderstood DE Carolinas witness McManeus's testimony. *See* 2018 DE Carolinas Rate Order, at 290.

Q. DID THE ORDER IN THE COMPANY'S PRIOR RATE CASE ALSO ADDRESS TREATMENT OF FUTURE ARO RELATED COAL ASH EXPENDITURES?

A. Yes. In the 2017 DE Progress Rate Case, the Company had requested a "run rate" to collect at least a portion of ongoing coal ash basin closure costs, which would have shifted the funding source for those costs from the Company and its investors to customers. The Commission rejected the Company's proposal. It stated:

> With respect to CCR remediation costs to be incurred during the period rates approved in this case will be in effect, the Commission determines that the "run rate" or the "ongoing compliance costs" mechanism advocated by DEP will not be approved. By requesting the creation of an ARO, in addition to the run rate, DEP concedes that treating CCR expenditures as a recurring test year expense is inadequate. Future annual costs, the evidence shows, are predicted to vary substantially from year to year. *Instead*, CCR remediation costs incurred by DEP during the period rates approved in this case will be in

> effect shall be booked to an ARO that shall accrue carrying costs at the approved overall cost of capital approved in this case (the net of tax rate of return, net of associated accumulated deferred income taxes). The Commission will address the appropriate amortization period in DEP's next general rate case, and, unless future imprudence is established, *will permit earning a full return on the unamortized balance*. While this ratemaking treatment will, in limited fashion, diminish the quality of DEP's earnings, over time, assuming reasonable and prudent CCR management practices, it permits appropriate recovery.

2018 DE Progress Rate Order, at 206 (emphasis added). The Commission's ruling puts the focus of the Company's cost recovery request where it belongs – on the Commission's examination of the prudence and reasonableness of the costs for which the Company seeks recovery in this case.

Q. HAVE YOU REVIEWED THE COMMISSION'S RECENTLY ISSUED ORDER IN THE DOMINION ENERGY NORTH CAROLINA ("DENC") CASE, DOCKET NO. E-22, SUB 562, ADDRESSING RECOVERY OF DENC'S COAL ASH BASIN CLOSURE COSTS?

A. Yes. I have reviewed sections of the DENC Order that address Finding of Fact Nos. 53-55, which specifically focus on the Commission's decision regarding recovery of financing costs during the Deferral Period (that is, the period from the time the coal ash basin closure costs, which the Order refers to as CCR Costs, are incurred until the time the costs are brought into rates), as well as recovery of financing costs (a return) on the unamortized balance of CCR Costs during the period after the costs are brought into rates and are being amortized (the Amortization Period). On these issues the Commission decided that:

- DENC *would* be allowed to recover its financing costs during the Deferral Period; in this respect the Commission came to the same decision as it had in both the 2017 DE Progress Rate Case and the 2017 DE Carolinas Rate Case.
- DENC *would not* be allowed to recover its financing costs during the Amortization Period, which the Commission decided should be ten years; in this respect the Commission's decision differs from its decisions in the 2017 DE Progress Rate Case and the 2017 DE Carolinas Rate Case.

The Commission made its decision to deny DENC a return during the Amortization Period even though it acknowledged that DENC's CCR Costs had been prudently incurred.

Q. DOES THE COMMISSION'S ORDER IN THE DENC CASE CAUSE YOU CONCERN?

A. Yes. It appears to run contrary to the Commission's Orders in both the 2017 DE Progress Rate Case and the 2017 DE Carolinas Rate Case, in which financing costs, at the companies' weighted average cost of capital, were allowed during the Amortization Period. I note that in the DENC case the Commission concluded, "based on the record as a whole … that it is appropriate to treat the CCR Costs as deferred operating expenses and not as costs of property used and useful within the meaning and scope of N.C.G.S. § 62-133(b) … ." (2020 DENC Order, p. 134). I am not familiar with the evidentiary record in the DENC case that underlies the Commission's decision, but I know that the classification of the CCR Costs that were at issue in the 2017 DE Carolinas Rate Case was a hotly debated issue between DE Carolinas and the Public Staff. In its Order in the 2017 DE Carolinas Rate Case, the Commission indicated that the Public Staff's insistence that CCR Costs were "deferred expenses" was "not persuasive, not supported by authority, and not determinative, given the nature of the deferral." 2018 DE Carolinas Rate Order, at 289. The Commission also found that the Public Staff's position was "incorrect as a matter of accounting," noting that "because under GAAP and FERC guidance ARO costs are capitalized. The nomenclature relied upon in GAAP and FERC is costs, assets, and liabilities, not 'expenses.'" 2018 DE Carolinas Rate Order, at 289-90. I see no reason for the Commission to come to a different conclusion using the same facts regarding the classification of the Company's CCR Costs at issue in this case.

Q. DO YOU HAVE ANY ADDITIONAL OBSERVATIONS REGARDING THE COMMISSION'S ORDER IN THE RECENT DENC CASE?

A. Yes. While I am not a lawyer, it appears to me that the Commission is seeking to find a result that is "fair" to the utility and to customers. I will leave it to the lawyers to argue about whether this is the proper standard for the Commission to employ. But there are a number of factors, based upon the Commission's Order in the 2017 DE Progress Rate Case, that I think the Commission should consider in weighing "fairness" in this case.

As I have already noted, the Commission rejected the Company's request for a "run rate," representing an ongoing annual level of CCR Costs the Company reasonably expected would be incurred into the future. The Commission "instead" (as stated in its Order) required the Company to continue to defer those ongoing costs. Those are the same costs that are at issue in this case. The Commission's direction seems clear to me: "*Instead*, CCR remediation costs incurred by DE Progress during the period rates approved in this case will be in effect shall be booked to an ARO that shall accrue carrying costs at the approved overall cost of capital approved in this case (the net of tax rate of return, net of associated accumulated deferred income taxes)." 2018 DE Progress Rate Order, at 206.

As discussed in the testimony of Company witnesses Newlin and Young, the Company has done what it was ordered to do, and it has raised the money to fund its ongoing CCR Costs – for which it now seeks recovery – from its investors. Doing so costs money, as those investors require a return on their investments. Requiring the Company to absorb this cost of money would impair its ability to earn its authorized return, as the Commission has already found. 2018 DE Carolinas Rate Order, at 290. Such a result would not seem to me to be the fair result that the Commission seeks.

Similarly, shortly after the 2017 DE Progress Rate Case had concluded, the Commission addressed the impact of the 2018 Federal Tax Cuts and Jobs Act ("Tax Act"). In particular, the Commission faced the issue of flow-back to customers of excess deferred income taxes (EDIT) resulting from the Tax Act – essentially, money previously collected by utilities from customers for future tax liabilities at the then prevailing tax rate, that needs to be returned to customers because the actual taxes to be paid will be at a lower tax rate. In effect, with respect to EDIT, customers prepaid for a cost which will now not materialize – and they should get their money back. In *its Order Addressing the Impact of the Federal Tax Cuts and Jobs Act* issued October 5, 2018 in Docket No. M-100, Sub 148, page 70, the Commission held:

> That excess deferred income taxes related to the decrease in the federal corporate income tax rate to 21% under the Tax Act for Cardinal, DENC, DEP, Piedmont, and PSNC, as appropriate, shall be held in a deferred tax regulatory liability account until they can be addressed for ratemaking purposes in each utility's next general rate case proceeding or in three years, whichever is sooner. These amounts will ultimately be returned to customers with interest reflected at the overall weighted cost of capital approved in each Company's last general rate case proceeding.

The interest portion of the flowback recognizes that customers are not getting their money right away.

With respect to the coal ash basin closure costs incurred during the period at issue in this case, the Company, with investor-supplied funds, in effect prepaid those costs rather than already having them funded by customers through the rates they pay. Ultimately, as those costs are brought into rates, and assuming the Commission finds that they have been prudently incurred, customers will pay – but the full costs to be paid include the cost of the funds advanced by investors. In my opinion, that treatment demonstrates the balance that the Commission indicates it seeks between the Company and its customers.

Q. DOES THE COMPANY AGREE WITH THE ADJUSTMENT PROPOSED BY WITNESS MANESS TO INCREASE THE AMORTIZATION PERIOD FOR DEFERRED AMOUNTS RELATED TO CAPITAL EXPENDITURES INCURRED THAT ARE NON-ARO RELATED?

A. No. As indicated by witness Maness, the requested amounts for recovery over five years are the return and depreciation associated with capital expenditures at active coal plants in compliance with coal ash closure requirements. His recommendation is to double the length of the amortization period to mitigate annual rate impacts to customers. The Public Staff has recommended extending amortization periods proposed by the Company when the amortization involves amounts to be collected from customers but recommends shortening amortization periods when the amortization involves amounts to be refunded to customers. The Company has considered annual rate impacts in its recommendation of the five year amortization and considered the Commission's decision in the 2017 DE Progress Rate Case in determining the amortization period.

Q. WHAT IS THE COMPANY'S POSITION REGARDING THE RECOMMENDATION BY WITNESS MANESS TO DISALLOW FUTURE DEFERRAL OF FUTURE CAPITAL COSTS RELATED TO NON-ARO COMPLIANCE PROJECTS?

A. In his recommendation, witness Maness is asking the Commission to reverse its previous authorization to defer such costs. In the 2017 DE Progress Rate Case, the Commission ruled on the Company's request to defer costs related to compliance with federal and state laws for coal combustion residuals. The Company's underlying petition to establish a deferral clearly articulated that the request was for the following:

> the deferral of all non-capital costs as well as the depreciation expense and cost of capital at the weighted average cost of capital for all capital costs related to activities required under the legislative and regulatory mandates outlined in paragraphs five and seven.[5]

Paragraphs five and seven referenced in this sentence identified federal regulations promulgated by the EPA regarding CCRs and state requirements under the Coal Ash Management Act. In the 2018 DE Progress Rate Case order, the Commission noted in Finding of Fact number 51:

> DEP expects to incur substantial costs related to CCRs in future years. It is just and reasonable to allow deferral of those costs, with a return at the overall cost of capital approved in this Order during the deferral period. Ratemaking treatment of such costs will be addressed in future rate cases.

[5] *Duke Energy Progress, LLC and Duke Energy Carolinas, LLC's Petition for an Accounting Order*, Docket Nos. E-2, Sub 1103 and E-7, Sub 1110, p. 14 (December 30, 2016).

While the Commission's ruling did not make a distinction between CCR-related costs that are associated with compliance activities considered an Asset Retirement Obligation ("ARO") and those that are not, the Company maintains that its previous request for deferral of costs to comply with federal and state laws related to CCRs included both ARO and non-ARO costs was authorized by the Commission after review and consideration of the Company's petition for deferral. Therefore, the Commission should not reverse its previous authorization to defer these costs.

Q. DO YOU HAVE ANY OTHER COMMENTS ON THE PUBLIC STAFF'S PROPOSED ADJUSTMENTS TO COAL ASH COMPLIANCE COSTS?

A. Witness Bednarcik addresses the validity of the cost associated with Mayo land and how in 2017 the company sought and was granted recovery of the land acquisition costs at Cape Fear and H.F. Lee. In addition, the Company objects to adjusting the deferred environmental costs for the recommended disallowance of $82,000 related to Mayo land, as these costs are not included in the deferred environmental costs.

Remaining Adjustments Opposed by the Company

Q. OF THE REMAINING ADJUSTMENTS THAT THE COMPANY OPPOSES, WHICH ONES ARE ADDRESSED BY OTHER COMPANY WITNESSES?

A. The following Public Staff adjustments from Dorgan Exhibit 1, Schedule 1, are addressed by other Company witnesses in rebuttal testimony, using the reference numbers:

Line 5 - Change in equity ratio from 53.00% to 50.00% equity

The Company opposes this adjustment for the reasons set forth in the rebuttal testimony of Company witness Newlin.

Line 7 - Change in return on equity from 10.3% to 9.00%

The Company opposes this adjustment for the reasons set forth in the rebuttal testimony of Company witness Hevert.

Line 8 – Adjust for cost of service reallocations - SWPA

The Company opposes the Public Staff's recommendations related to changes in allocation factors used in the Company's Cost of Service Study, as explained in the rebuttal testimony of Company witness Hager.

Line 10 – Update revenues, customer growth and weather to February 29, 2020

The Company opposes this adjustment. Company witness Pirro sets forth the opposition to the kWh usage used by the Public Staff in this adjustment. In addition, the Company opposes the calculation methodology used by the Public

Staff to translate the kWh into a revenue requirement impact. The Public Staff adjusted the Company's labor expense for changes in kwh usage. Since labor expense is adjusted in NC-1300, the Company disagrees with its inclusion in this adjustment.

Line 15 – Adjust executive compensation, Line 23 - Adjust incentives and, Line 34 –Adjust Board of Directors expense

The Company opposes these adjustments for the reasons set forth in the rebuttal testimony of Company witness Metzler.

Line 29 – Adjust Asheville production displacement

The Company opposes this adjustment for the reasons set forth in the rebuttal testimony of Company witness Turner.

Line 31– Adjust EOL nuclear materials & supplies reserve expense

The Company opposes these adjustments for the reasons set forth in the rebuttal testimony of Company witness Henderson.

Line 33 – Adjust lobbying expenses

The Company opposes the Public Staff's recommendation for the reasons set forth in the rebuttal testimony of Company witness Angers.

Line 36 – Adjust nuclear decommissioning expense

The Company opposes the Public Staff's recommendation for the reasons set forth in the rebuttal testimony of Company witnesses Doss and Hevert.

Q. ARE THERE OTHER CHANGES INCORPORATED IN SMITH REBUTTAL EXHIBIT 1 THAT ARE NOT YET ADDRESSED IN YOUR REBUTTAL TESTIMONY?

A. Yes. Smith Rebuttal Exhibit 1 also revises amounts previously presented in Smith Supplemental Exhibit 1, filed March 13, 2020, for the following pro forma adjustments to test period amounts:

Line 2 – Update fuel cost to proposed rate

The amount previously shown on Smith Supplemental Exhibit 1 filed on March 13, 2020, was incorrect due to a formula error on NC-0202 line 8, now corrected in Smith Rebuttal Exhibit 1.

Line 10 – Adjust for post test year additions to plant in service

The amount previously shown on Smith Supplemental Exhibit 1 filed on March 13, 2020, has been updated to the forecast for Asheville Combined Cycle Unit 8, which went into service on April 5, 2020. The adjustments are now reflected in Smith Rebuttal Exhibit 1.

Line 22 – Synchronize interest expense with end of period rate base

This adjustment to income tax expense has been revised to reflect the impacts of revisions discussed earlier in my testimony affecting rate base and the associated annualized interest expense.

Line 32 – Reflect retirement of Asheville Steam Generating Plant

The amount previously shown on Smith Supplemental Exhibit 1 filed on March 13, 2020, was incorrect due to a formula error on NC-3203 lines 18 and 47, which are now corrected in Smith Rebuttal Exhibit 1.

Line 34 – Amortize deferred balance of Asheville Combined Cycle

The amount previously shown on Smith Supplemental Exhibit 1 filed on March 13, 2020, has been updated for the forecast for Asheville Combined Cycle Unit 8, which went into service on April 5, 2020. The adjustments are now reflected in Smith Rebuttal Exhibit 1.

III. <u>DEFERRAL REQUEST FOR GRID IMPROVEMENT PLAN</u>

Q. ARE THERE ISSUES RAISED BY INTERVENING PARTIES REGARDING THE COMPANY'S REQUEST FOR AUTHORIZATION TO DEFER GRID IMPROVEMENT PLAN COSTS THAT YOU WOULD LIKE TO ADDRESS?

A. Yes. Many comments by intervening parties are addressed by Company witness Oliver in his rebuttal testimony, but there are a few topics that I will address with regard to cost recovery and ratemaking practices.

Q. HOW ARE CUSTOMER RATES AFFECTED BY AUTHORIZATION TO DEFER GRID IMPROVEMENT PLAN COSTS?

A. Cost recovery is a separate and distinct process from deferral of costs. Customer rates in this proceeding are not impacted by the Commission's decision to permit cost deferral.

Q. HOW DOES THE COMPANY BENEFIT FROM AUTHORIZATION TO DEFER COSTS?

A. Authorization to defer costs allows the Company the opportunity to avoid adverse financial impacts of regulatory lag, but only to the extent the Commission ultimately allows recovery of the deferred cost in a future rate proceeding. Although the Company has typically experienced adverse regulatory lag impacts related to its distribution and transmission investments in the past, the types of investments, the level of costs, and the overall scale of the Grid Improvement Plan leads the Company to request deferral of the associated revenue requirements. If allowed to defer Grid Improvement Plan related costs, the Company still bears risk of recovering the costs in a future rate proceeding.

Q. PLEASE CLARIFY COSTS FOR WHICH DEFERRAL IS REQUESTED.

A. Contrary to what is implied in some intervenor testimony, the Company is not requesting deferral of its capital expenditures. DE Progress requests to defer the traditional revenue requirement amounts associated with the Grid Improvement Plan capital expenditures. Following traditional ratemaking principles, when the Company makes capital investments as part of the Grid Improvement Plan, the cost to be deferred will be the depreciation and return on investment for the completed plant in service. For example, if the Company invests in a transmission-related capital project that takes six months to complete, there would be no capital costs deferred during the six-month construction period. But once the project is completed and the transmission asset is in service, the associated deferral of costs would be the annual depreciation expense and return on the investment. For clarity, if the Company spends $1.2 billion in capital over a three-year period, the deferred cost associated with that amount is not $1.2 billion, but instead is three years of annual depreciation and return on that investment, beginning at the date the assets are completed and in service. In addition to these traditional revenue requirement amounts of depreciation and return on investment, the deferral would include the financing costs related to the amounts that are unrecovered during the period between the in-service date of the asset and when Company rates are updated to include cost recovery of the assets.

Q. DO YOU AGREE WITH THE RESTRICTIONS TO COST DEFERRAL RECOMMENDED BY PUBLIC STAFF WITNESS MANESS?

A. No. I do not think it is appropriate to exclude costs that are directly related to the Grid Improvement Plan programs for which the Company is requesting deferral. In his direct testimony filed April 13, 2020, witness Maness proposes to exclude deferral of a return on the balance of deferred incremental capital costs and incremental expenses. This return represents the financing costs the Company will incur between the time the Grid Improvement Plan costs are incurred and the time that such costs are approved for recovery in future rates.

The three-year Grid Improvement Plan comprises numerous projects that will have short construction periods and therefore will be quickly placed into electric service, e.g., after one month, three months, six months, etc. Given the length of time to complete a general rate case, if the Company had a rate case every year, the delay in cost recovery, from the month that the grid improvement is placed in service to the month that the costs are reflected in the Company's new base rates, could be significant – on average more than a year. If rate cases did not occur every year, then this lag in the timing of cost recovery is multiplied. In contrast, such lengthy delays have been avoidable for large generation investments, where rate cases are often timed around the estimated completion date of the single large investment. In such rate cases, the Company frequently requests and is granted recovery of the costs incurred from the date the generating plant is placed into service to the date that new rates become effective, through a regulatory deferral and amortization of the costs. As a result, there can be minimal regulatory lag for this type of investment. In contrast, the impact of regulatory lag for the Grid Improvement Plan is substantial, and the Company believes it should be given the opportunity to recover <u>all</u> prudently incurred Grid Improvement Plan costs through future rate adjustments by being allowed to defer all of the costs associated with the Grid Improvement Plan, including all financing costs.

Q. PLEASE COMMENT ON THE ANALYSIS OF RETURN ON EQUITY (ROE) IMPACTS PREPARED BY THE PUBLIC STAFF AND ADDRESSED IN THE SUPPLEMENTAL TESTIMONY OF WITNESS MANESS.

A. Witness Maness performed an analysis of the estimated impact on the Company's ROE if deferral of Grid Improvement Plan amounts is not authorized. The Public Staff's analysis differs, in some respects, from the analysis prepared and filed by the Company as part of my direct testimony. The main difference is that the Public Staff analysis is based on a subset of five Grid Improvement Plan programs, and consequently a considerably smaller amount of capital expenditures. The negative impact in ROE as estimated by the Public Staff reached 25 basis points in the final year of the program (2022), as compared to over 100 basis points per the Company's computation. Witness Maness noted that under "normal circumstances" he would not recommend deferral for this magnitude of ROE impact. However, he concluded that he would not object to the Company's request for deferral of amounts related to the subset of five programs in this case for one reason. His single reason for not opposing the deferral was his consideration of the Commission's comments in its order in DEC's 2017 Rate Case, where it stated that it might rely on leniency in imposing the "extraordinary expenditure" test of deferrals when considering Grid Improvement Program deferrals. I think it is worth noting, however, the extensive rebuttal testimony of Company witness Oliver addressing the Public Staff's recommendation that only five programs should qualify for deferral. Witness Oliver's testimony provides substantial support for authorization of deferral for all Grid Improvement Plan amounts, and as such, I contend that the ROE impact presented in my direct testimony is the appropriate impact for the Commission to consider in making its decision.

Q. IS DEFERRAL OF COST AN EXAMPLE OF SINGLE ISSUE RATEMAKING?

A. No. Contrary to the allegation made by some intervenors, as noted above, deferral accounting is not ratemaking at all. Authorization to defer costs does not authorize cost recovery or result in a change in customer rates. Nor is it a pre-approval of cost recovery. Deferred revenue requirements must be considered for recovery in a general rate case proceeding, and in conjunction with all other electric costs subject to consideration in the proceeding.

Q. WHEN DEFERRED COSTS ARE PRESENTED IN FUTURE RATE PROCEEDINGS FOR RECOVERY, WILL THE COSTS BE AMBIGUOUS?

A. No. In the direct testimony of North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, Southern Alliance for Clean Energy, and the North Carolina Sustainable Energy Association ("NCJC, et al.") witness Alvarez, he comments that "If deferral accounting is approved, we do not know what DE Progress (or DE Carolinas) will spend on the Grid Improvement Plan, and how the spending will be split among the programs.

This ambiguity is extremely concerning to me, and I believe it should concern the Commission as well." For clarity, if the Commission authorizes the deferral of costs related to the Grid Improvement Plan, the Company will initially record the expenditures for all programs according to normal FERC accounting requirements. This means that expenditures will be classified functionally (i.e., production, transmission, distribution, general) and recorded to the appropriate electric plant or electric or operating expense account as if no deferral exists. As a second step, the Company will record special journal entries to reclassify the costs which it is authorized to defer into a regulatory asset account. The specific costs must be identifiable and tracked, according to the Grid Improvement Plan programs as described in Oliver Exhibit 10, to record the deferral accounting entry. As such, when the Company requests cost recovery of the deferred amounts in a future general rate case, the details of the deferred amounts will be known. Such details must be known in order for the Commission to assess the reasonableness and prudency of the expenditures, which is a prerequisite for approval of recovery.

Q. IS IT ACCURATE TO DESCRIBE THE AUTHORIZATION FOR DEFERRAL AS GRANTING THE COMPANY "A POT OF MONEY IT CAN INVEST AS IT WISHES"?

A. No. This characterization, made by NCJC, et al. witness Stephens, incorrectly infers that the investments for which the Company is granted authorization for cost deferral are not subject to review and scrutiny and a finding of reasonableness and prudency as a prerequisite for cost recovery. The implication is that the Company bears no risk with regard to amounts that the Company spends and thus is incented to spend indiscriminately. On the contrary, Grid Improvement Plan expenditures, like all expenditures, are at risk for recovery. The authorization to defer the costs does not guarantee recovery of the costs. Instead, it simply allows the Company to identify the costs for deferral and record them as a regulatory asset for *potential* future recovery through future rate adjustments.

The estimated amounts related to the Grid Improvement Plan are provided in the Company's filed testimony and exhibits to allow the Commission to determine whether the costs should qualify for deferral treatment. However, it is the actual costs incurred that are ultimately deferred and then brought forward for potential cost recovery. Recovery will ultimately be based on actual costs, not estimated costs, nor an estimated total amount for the entire program. A determination will be made as to the reasonableness and prudency of the actual program expenditures, and those found to be unreasonable or imprudent will be disallowed recovery. Intervenors express concern that customers bear the risk of cost overruns or scope shortcomings that could be addressed by the imposition of spending caps. I would note that although the Commission has the discretion to impose such caps on the amounts the Company is authorized to defer, the Commission at present has full authority to address cost overruns or scope issues during a future general rate case when the deferred cost are presented for recovery, and the Company bears the full risk of any disallowances the Commission could choose to impose.

IV. ISSUES RAISED BY OTHER INTERVENORS

Q. ARE THERE ANY OTHER ISSUES RAISED BY OTHER INTERVENING PARTIES THAT YOU WOULD LIKE TO ADDRESS?

A. Yes. I would like to address comments by Carolina Utility Customers Association witness O'Donnell regarding customer rate impacts of "grid modernization" as presented in Table 3 of his testimony. The grid modernization rate impact presented by witness O'Donnell is related to the PowerForward program, not the Grid Improvement Plan presented by Company witness Oliver in this proceeding. Witness O'Donnell uses information from February 2017 that he previously presented in his direct testimony filed in the 2017 DE Progress Rate Case. Not only is the PowerForward program data presented by witness O'Donnell outdated, but, as discussed in Company witness Oliver's rebuttal testimony, the Grid Improvement Plan is dramatically different in scope than the earlier PowerForward program.

V. PROPOSED EDIT RIDER

Q. DOES THE COMPANY AGREE WITH THE RECOMMENDATIONS OF PUBLIC STAFF WITNESS DORGAN REGARDING THE FLOWBACK OF EDIT TO CUSTOMERS?

A. No. Witness Dorgan recommends a much faster flowback of unprotected EDIT relating to property, plant, and equipment – over 5 years – than the 20-year flowback proposed by the Company. The Company continues to believe that the EDIT Rider it has proposed is a fair balancing of relevant issues. As noted in Company witness Newlin's rebuttal testimony, the proposed EDIT rider returns amounts that are clearly owed to customers. However, witness Newlin explains that it is prudent for any proposal for return of these amounts to customers to consider the impact on the financial strength of the Company, which ultimately affects its cost to serve customers. He explains in detail the adverse impact that will occur if a 5-year flowback is required.

Witness Dorgan notes on page 41 of his direct testimony that the EDIT funds "rightfully belong to the ratepayers and should be returned to them as soon as reasonably possible." The Company agrees. He also states that the Company's proposal is "not supportable by any logical accounting or ratemaking principle." As explained in the rebuttal testimony of Company witness Newlin, the ratemaking principles that the Company is considering in its proposed EDIT Rider are rate volatility and minimizing costs to customers – financing costs, in particular. On page 42 of his direct testimony, witness Dorgan asserts:

> Additionally, refunding the unprotected EDIT over five years allows the Company to properly plan for any future credit needs while refunding ratepayer dollars in a reasonable time. The Public Staff has provided the Company with the benefit of removing the total amount of the unprotected EDIT credit from rate base in the current case, thus providing the Company with an increase in rates to moderate any cash flow issues, to the extent they would exist. The financing cost to the Company will be imposed

ratably over the period that the EDIT is returned through the levelized rider.

As explained in the rebuttal testimony of Company witness Newlin, the Company does not agree with his assessment that his recommendation will appropriately moderate cash flow issues.

Witness Dorgan's recommended adjustments to the Company's proposal are to shorten the time period in which the Company returns funds to customers. As I noted earlier in my rebuttal testimony, the Public Staff's recommendations on amortization periods tends to be asymmetrical; extending amortization periods proposed by the Company when the amortization involves amounts to be collected from customers but shortening amortization periods when the amortization involves amounts to be refunded to customers. The Company continues to oppose this asymmetrical treatment, especially given the cash flow concerns raised by Company witness Newlin in his rebuttal testimony.

VI. CONCLUSION

Q. IS THE COMPANY PROPOSING ANY CHANGE IN THE REVENUE REQUIREMENT SOUGHT BY THE COMPANY IN THIS PROCEEDING?

A. No, not at this time**.**

Q. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-2, SUB 1219
DOCKET NO. E-2, SUB 1193

In the Matter of: **DOCKET NO. E-2, SUB 1219** Application of Duke Energy Progress, LLC For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina **DOCKET NO. E-2, SUB 1193** Petition of Duke Energy Progress, LLC for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence, Michael and Dorian and Winter Storm Diego	)	**SETTLEMENT TESTIMONY OF KIM H. SMITH FOR DUKE ENERGY PROGRESS, LLC**

I. INTRODUCTION

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

A. My name is Kim H. Smith, and my business address is 550 South Tryon Street, Charlotte, North Carolina. I am a Director of Rates & Regulatory Planning, employed by Duke Energy Carolinas, LLC ("DE Carolinas"), testifying on behalf of Duke Energy Progress, LLC ("DE Progress" or the "Company").

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS DOCKET?

A. Yes. I filed direct testimony and exhibits on October 30, 2019. I also filed supplemental direct testimony and exhibits on March 13, 2020, and rebuttal testimony and exhibits on May 4, 2020.

II. PURPOSE AND SCOPE

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support the Agreement and Stipulation of Partial Settlement ("Partial Settlement") between the Company and the Public Staff ("Stipulating Parties") by commenting on certain accounting and ratemaking adjustments agreed upon therein.

Q. DO YOU HAVE ANY EXHIBITS TO YOUR SETTLEMENT SUPPORTING TESTIMONY?

A. Yes. Smith Partial Settlement Exhibit 1 shows the Company's revised requested increase incorporating the provisions of the Partial Settlement. This exhibit starts with the original revenue increase as filed in the Company's October 30, 2019 filing in the proceeding and incorporates adjustments included in the Company's supplemental and rebuttal filings. This adjusted total is further modified by adjustments that reflect settled issues in order to compute the Company's revised requested revenue increase in this proceeding. Smith Partial Settlement Exhibit 2 summarizes the total revenue adjustments proposed in this proceeding, including the proposed increase in base rates and the net reduction in revenues reflected in existing and proposed riders, as revised to reflect settled issues. Smith Partial Settlement Exhibit 3 reconciles the revenue requirement as presented in my rebuttal testimony to the revenue requirement presented in this testimony. Smith Partial Settlement Exhibit 4 is an updated proposed EDIT rider that reflects removal of protected EDIT to be refunded through base rates.

III. PARTIAL SETTLEMENT WITH PUBLIC STAFF

Q. DOES THE COMPANY BELIEVE THE PARTIAL SETTLEMENT REPRESENTS A BALANCED COMPROMISE THAT PROVIDES AN EQUITABLE RESOLUTION FOR CERTAIN ITEMS IN THIS PROCEEDING FOR ITS SHAREHOLDERS, CUSTOMERS AND OTHER STAKEHOLDERS?

A. Yes. The Company believes the Partial Settlement with the Public Staff balances the financial impact of the rate increase on our customers with the Company's need to recover its revenue requirement, for the items included in the Partial Settlement, and our obligation to provide safe and reliable electric utility service to our customers.

Q. PLEASE EXPLAIN THE ACCOUNTING ADJUSTMENTS INCLUDED IN THE PARTIAL SETTLEMENT.

A. While the complete list of adjustments is described in the Partial Settlement, the following are additional comments on certain accounting adjustments identified in the Partial Settlement:

1. Storm costs

The Stipulating Parties agree to the adjustments reflected in the Partial Settlement related to storm cost deferral and amortization, and that the Company will proceed with filing a petition to securitize the storm costs incurred in response to Hurricanes Florence, Michael, Dorian, and Winter Storm Diego. For purposes of settlement, the Stipulating Parties also agree upon the assumptions to be used in the subsequent securitization docket for purposes of demonstrating quantifiable benefits to customers of securitization. In addition, the Stipulating Parties agree that a storm cost recovery rider, initially set at $0, should be established in this rate case to provide the Company a mechanism to request recovery of its storm costs if the Company is unable to securitize its storm costs.

2. Normalize storm costs

The Stipulating Parties agree to incorporate the Public Staff's recommendation to normalize storm expenses based on a 10-year average of storm costs that are not significant enough to be considered for securitization.

3. Adjust O&M for executive compensation

As noted in my direct testimony, the Company has made an adjustment to remove 50 percent of the compensation of the five Duke Energy executives with the highest amounts of compensation. In the Partial Settlement, the Company has agreed to also remove 50 percent of the benefits associated with those five executives.

4. Amortize rate case expenses

The Stipulating Parties agree to amortize Company rate case expenses over a 5-year amortization period. The Stipulating Parties agree that the deferred balance will not be included in the Company's rate base, and therefore will not earn a return.

5. Adjust aviation expenses

The Stipulating Parties agree to an adjustment that removes 50% of the aviation costs allocated to DE Progress, as proposed in my direct testimony. In addition, the Company agrees with the Public Staff adjustment to remove aviation costs allocated to DE Progress related to commercial international flights.

6. Adjust incentives included in O&M labor expenses

The Stipulating Parties agree to remove certain incentive pay related to earnings per share and total shareholder return for senior leaders within the Company.

7. Adjust sponsorships and donations and outside services expense

The Stipulating Parties agree that certain sponsorships and donations as well as outside services expenses should be removed.

8. Amortize severance costs

The Stipulating Parties agree to amortize test period severance costs over a 3-year amortization period. The Parties agree that the deferred balance will not be included in the Company's rate base, and therefore will not earn a return.

9. Adjust lobbying and Board of Directors' related expense

The Stipulating Parties agree to remove (a) certain O&M expenses considered to be related to lobbying activities, and (b) a portion of the Company's expenses related to its Board of Directors.

10. W. Asheville Vanderbilt 115kV Project

The Stipulating Parties agree that the adjustment to the W. Asheville Vanderbilt 115kV project reflected in the Partial Settlement should be accepted, subject to unsettled jurisdictional and class allocation factor methodology differences.

11. Adjust credit card fees

The Stipulating Parties agree that the Company's adjustments to credit card fees as proposed in my rebuttal testimony and exhibits are acceptable.

12. End-of-Life nuclear materials and supplies inventory

The Stipulating Parties agree that the adjustments to end-of-life nuclear materials and supplies reserve expense proposed by the Public Staff should be accepted.

13. Asheville Combined Cycle Deferral

The Stipulating Parties agree to amortize the Asheville Combined Cycle deferral costs over a 4-year amortization period with a levelized return.

14. Adjust Asheville Combined Cycle accumulated depreciation

The Stipulating Parties agree to an adjustment to accumulated depreciation reserve related to Asheville Combined Cycle to correct an error in the Company's rebuttal filing.

15. Asheville production displacement adjustment

The Stipulating Parties agree to reduce the Company's non-fuel variable O&M expense to account for production displacement.

16. Flowback of protected federal EDIT

The Stipulating Parties agree to refund certain amounts owed to customers related to excess deferred income taxes, resulting from the reduction in federal corporate income taxes according to the Tax Cuts and Jobs Act, through a reduction in base rates rather than through a rider. The certain amounts are the "protected" EDIT amounts, generally related to Property, Plant and Equipment, for which there are specific ratemaking requirements prescribed by the IRS.

17. CertainTeed payment obligation

The Public Staff agrees to withdraw its adjustment related to CertainTeed payment obligation. The Company removed this expense from this proceeding in its supplemental filing. The Stipulating Parties maintain their respective positions on this item in the DEP fuel proceeding in Docket No. E-2, Sub 1204.

IV. UPDATES TO THE COMPANY'S TEST PERIOD OPERATING EXPENSES IN RESPONSE TO THE PARTIAL SETTLEMENT

Q. HOW HAS THE COMPANY INCORPORATED THE PARTIAL SETTLEMENT PROVISION RELATED TO STORM COSTS INTO THIS FILING?

A. To properly reflect the agreement of the Stipulating Parties for DE Progress to pursue securitization of storm costs of Hurricanes Florence, Michael and Dorian and Winter Storm Diego, the Company has changed its original pro forma adjustment, which amortized the deferred balance of storm costs over 15 years, including a return on the unamortized balance, to an adjustment that removes amounts related to these storms from test period rate base and test period expenses. Specifically, pro forma number 29 removes the net book value of capitalized storm repair costs from rate base and removes the associated annual depreciation expense from electric expenses.

Q. WHAT OTHER ADJUSTMENTS ARE BEING PROPOSED AS A RESULT OF THE PARTIAL SETTLEMENT?

A. Three new adjustments are necessary to incorporate the Partial Settlement impacts into the revenue increase proposed by the Company.

37 – Amortize protected EDIT

Electric operating expenses are updated to reflect annual amortization of protected EDIT. The amount of amortization is based on compliance with Internal Revenue Service rules related to protected EDIT. In addition, the

Company's adjustment reduces the protected EDIT balance in rate base by one year of amortization.

38 – Adjust expenses for settlement items

This adjustment removes agreed upon amounts from electric expenses, as stated in the Partial Settlement. Items include sponsorship expenses, expenses the Public Staff considers to be lobbying-related, Board of Directors expenses, and specific Outside Services charges.

39 – Normalize storm costs

This adjustment incorporates the Public Staff's recommendation to normalize storm expenses, as agreed to in the Partial Settlement, based on a 10-year average of storm costs that are not significant enough to be considered for securitization.

In addition, the following previously filed adjustments are being updated as a result of the Partial Settlement.

10 - Adjust for post test year additions to plant in service

13 - Normalize O&M labor expenses

V. OTHER ADJUSTMENTS/ITEMS

Q. ARE THERE ANY OTHER ADJUSTMENTS THE COMPANY IS PROPOSING?

A. Yes. Certain test period adjustments by nature are affected by changes made to other adjustments. In this case, adjustment numbers 12, 22, and 23 are updated to reflect the impact of changes to other adjustments.

Q. PLEASE EXPLAIN THE REVISIONS TO THE COMPANY'S PROPOSED EDIT RIDER SHOWN ON SMITH PARTIAL SETTLEMENT EXHIBIT 4.

A. As a result of the Partial Settlement, the Company has removed the amount of protected EDIT from its proposed rider and included the refund of this amount to customers in its proposed base rates. Other amounts to be refunded to customers, made up of unprotected federal EDIT, state EDIT and deferred revenue, are included in the revised rider as originally proposed.

Q. IN YOUR OPINION, DOES THE PARTIAL SETTLEMENT REFLECT A FAIR, JUST, AND REASONABLE RESOLUTION OF THE ISSUES IT ADDRESSES?

A. Yes. As stated previously, the Partial Settlement is the result of negotiations between the Stipulating Parties and resolves many of the issues in the case between the Stipulating Parties without the necessity of contentious litigation. Therefore, we respectfully request that the Commission approve the Partial Settlement in its entirety.

VI. CONCLUSION

Q. DO YOUR PARTIAL SETTLEMENT EXHIBITS REFLECT A CHANGE IN THE REVENUE REQUIREMENT SOUGHT BY THE COMPANY IN THIS PROCEEDING?

A. Yes. The Company requests a revenue increase from base rates of $412.8 million. In addition, the Company requests that customer rates be reduced by

$91 million through its proposed riders. As shown on Smith Partial Settlement Exhibit 2, the net proposed increase in revenue is $321.6 million. This is a $142.0 million reduction from the amount proposed in the Company's Application.

Q. DOES THIS CONCLUDE YOUR SETTLEMENT TESTIMONY?

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of:

Application of Duke Energy Progress, LLC	)	**SECOND SUPPLEMENTAL**
for Adjustments of Rates and Charges	)	**DIRECT TESTIMONY OF**
Applicable to Electric Service in North	)	**KIM H. SMITH FOR DUKE**
Carolina	)	**ENERGY PROGRESS, LLC**

I. INTRODUCTION AND PURPOSE

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

A. My name is Kim H. Smith and my business address is 550 South Tryon Street, Charlotte, North Carolina. I am a Director of Rates & Regulatory Planning, employed by Duke Energy Carolinas, LLC ("DE Carolinas"), testifying on behalf of Duke Energy Progress, LLC ("DE Progress" or the "Company").

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS DOCKET?

A. Yes. I filed direct testimony and exhibits on October 30, 2019. I also filed supplemental direct testimony and exhibits on March 13, 2020, rebuttal testimony and exhibits on May 4, 2020, and settlement testimony and exhibits on June 2, 2020.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to update the Company's proposed revenue increase. An update is necessary to incorporate certain known and measurable changes through May 31, 2020. The specific items updated are identified later in my testimony.

II. UPDATES TO THE COMPANY'S TEST PERIOD OPERATING REVENUES, EXPENSES, AND RATE BASE

Q. WHAT ADJUSTMENTS TO REVENUE REQUIREMENTS ARE PROPOSED BY THE COMPANY?

A. The Company is updating its proposed revenue requirements to incorporate certain known and measurable changes to its revenues, expenses and rate base amounts previously filed in this Docket. These updates are limited, and are based on actual revenue, expense, and rate base amounts as of May 31, 2020. The updates are necessary and appropriate to provide the Company a reasonable opportunity to earn the return on equity approved by the Commission in this proceeding. Due to the extraordinary circumstances of the COVID-19 pandemic, the hearing and corresponding Commission order establishing rates in this case have been unavoidably delayed, and the Company voluntarily waived its right to implement its original proposed rates after the 270 days suspension period. Consequently, updating the Company's costs closer in time to the start of the hearing gives a more recent depiction of the Company's actual costs to serve its customers, which should be reflected in the Company's rates.

Q. WHAT OTHER ADJUSTMENTS ARE BEING PROPOSED AS A RESULT OF THE UPDATES DISCUSSED ABOVE?

A. Since the Company is updating its post-test year capital additions to reflect completed electric plant in service as of May 31, 2020, it is appropriate to also update the timing of the Company's requested deferral period for Grid Improvement Plan ("GIP") costs. The Company is requesting deferral of investments not included in this rate case. Now with the inclusion of plant in service through May 31, 2020, the Company's requested deferral of incremental GIP costs would start with plant placed in service beginning June 1, 2020 and continuing through December 31, 2022.

Q. WHAT ADDITIONAL INFORMATION IS BEING SUBMITTED IN THIS FILING?

A. DE Progress is also providing information which reflects the impact of the following settlement agreements it has entered into with intervenors (the "Intervenor Settlements"):

- Settlement Agreement with Harris Teeter, LLC filed June 8, 2020;
- Settlement Agreement with the Commercial Group filed June 9, 2020; and
- Agreement and Stipulation of Settlement with Carolina Industrial Group for Fair Utility Rates III filed June 26, 2020.

Commission approval of these agreements would result in revenue requirements based on 9.75% return on equity ("ROE") and a capital structure of 52% common equity and 48% long-term debt.

As described later in my testimony, the Company is submitting additional exhibits in this filing demonstrating the reduction to its proposed revenue increase (now based on post-test period updates through May 31, 2020) resulting from the ROE and capital structure agreed to in the Intervenor Settlements.

Q. WHICH "PRO FORMA" ADJUSTMENTS TO TEST PERIOD AMOUNTS ARE BEING UPDATED IN THIS FILING?

The following table shows the particular items revised in this filing in bold text.

ADJUSTMENTS TO OPERATING REVENUES AND EXPENSES				
Line No.	**Adjustment Title**	**Witness**	**May 2020 Update**	**ROE or Cap Str Change**
1	Annualize retail revenues for current rates	Pirro		

ADJUSTMENTS TO OPERATING REVENUES AND EXPENSES				
Line No.	**Adjustment Title**	**Witness**	**May 2020 Update**	**ROE or Cap Str Change**
2	Update fuel costs to proposed rate	McGee		
3	Normalize for weather	Pirro		
4	**Annualize revenues for customer growth**	**Pirro**	**X**	
5	Eliminate unbilled revenues	Smith		
6	Adjust for costs recovered through non-fuel riders	Smith		
7	Adjust O&M for executive compensation	Smith		
8	Annualize depreciation on year end plant balances	Smith		
9	Annualize property taxes on year end plant balances	Smith		
10	**Adjust for post-test year additions to plant in service**	**Smith**	**X**	
11	Amortize deferred environmental costs	Smith		
12	**Annualize O&M non-labor expenses**	**Smith**	**X**	
13	**Normalize O&M labor expenses**	**Smith**	**X**	
14	Update benefits costs	Smith		
15	Levelize nuclear refueling outage costs	Smith		
16	Amortize rate case costs	Smith		
17	Adjust aviation expenses	Smith		
18	Adjust for approved regulatory assets and liabilities	Smith		
19	**Adjust for merger related costs**	**Smith**	**X**	
20	Amortize severance costs	Smith		
21	Adjust for NC income tax rate change	Smith		
22	**Synchronize interest expense with end of period rate base**	**Smith**	**X**	**X**
23	**Adjust cash working capital for present revenue annualized and proposed revenue**	**Smith**	**X**	**X**
24	Adjust coal inventory	Smith		
25	Adjust credit card fees	Smith		
26	Adjust for new depreciation rates	Smith		
27	Adjust vegetation management expenses	Smith		
28	Adjust reserve for end of life nuclear costs	Smith		
29	**Update deferred balance and amortize storm costs**	**Smith**	**X**	
30	Adjust other revenue	Pirro		
31	Adjust for change in NCUC regulatory fee	Smith		

ADJUSTMENTS TO OPERATING REVENUES AND EXPENSES				
Line No.	**Adjustment Title**	**Witness**	**May 2020 Update**	**ROE or Cap Str Change**
32	Reflect retirement of Ashville Steam Generating Plant	Smith		
33	Adjust for CertainTeed payment obligation	Smith		
34	Amortize deferred balance Asheville Combined Cycle	Smith		
35	Adjust purchased power	Smith		
36	Correct Lead-Lag - Supplemental	Smith		
37	Amortize Protected EDIT – Partial Settlement	Smith		
38	Remove certain Settlement Items – Partial Settlement	Smith		
39	Normalize for storm costs – Partial Settlement	Smith		

Q. DO THE PROPOSED ADJUSTMENTS IMPACT THE AGREEMENT AND STIPULATION OF PARTIAL SETTLEMENT BETWEEN THE COMPANY AND THE PUBLIC STAFF FILED ON JUNE 2, 2020 ("PARTIAL SETTLEMENT")?

A. No. In the Partial Settlement, the Company and the Public Staff agreed to certain adjustments to the revenue requirement in the Company's rebuttal filing on May 4, 2020. The updates through May proposed in this filing are new and were not included in the Company's prior supplemental filing and therefore, were not part of the Partial Settlement with the Public Staff. However, to the extent a calculation methodology for a pro forma adjustment was agreed to in the Partial Settlement, the same methodology has been applied to the May updates.

Q. DO YOU HAVE ANY EXHIBITS TO YOUR SECOND SUPPLEMENTAL DIRECT TESTIMONY?

A. Yes. I am providing the following exhibits:

- Smith Second Supplemental Exhibit 1 presents the impact of additional adjustments to test period operating income and rate base that the Company is supporting based on post-test period updates through May 31, 2020. Page 1 of the Exhibit summarizes the adjustments and the details for each adjustment presented on the subsequent pages.
- Smith Second Supplemental Exhibit 1-S takes Smith Second Supplemental Exhibit 1 and layers in the additional impacts of the Intervenor Settlements – i.e., the 9.75% ROE and 52/48 capital structure.
- Smith Second Supplemental Exhibit 2 summarizes the proposed total revenue adjustments in this proceeding, reflecting both the proposed increase in base rates and the net reduction in revenues reflected in the two proposed EDIT riders and the Regulatory Asset and Liability rider.
- Smith Second Supplemental Exhibit 2-S takes Smith Second Supplemental Exhibit 2 and layers in the additional impacts of the Intervenor Settlements – i.e., the 9.75% ROE and 52/48 capital structure.
- Smith Second Supplemental Exhibit 3 is a reconciliation of adjustments to base revenue requirement. The reconciliation begins with the $412.8 million base revenue requirement proposed by the Company in my Settlement testimony filed June 2, 2020.[1] Specific impacts related to May

[1] This amount incorporates impacts of the Agreement and Stipulation of Partial Settlement between DE Progress and the Public Staff filed on June 2, 2020.

2020 updates are itemized and summarized to show the resulting base revenue requirement of $438.2 million after May updates.

- Smith Second Supplemental Exhibit 3-S takes Smith Second Supplemental Exhibit 3 and layers in the additional impacts of the Intervenor Settlements – i.e., the 9.75% ROE and 52/48 capital structure to show the resulting base revenue requirement of $389.4 million.
- Smith Second Supplemental Exhibit 4-S is an updated EDIT rider which incorporates the impacts of the Intervenor Settlements on the return component of the rider.

III. CONCLUSION

Q. DO YOUR SECOND SUPPLEMENTAL EXHIBITS REFLECT A CHANGE IN THE REVENUE REQUIREMENT SOUGHT BY THE COMPANY IN THIS PROCEEDING?

A. Yes. If the Commission approves the Intervenor Settlements, the Company requests a revenue increase from base rates of $389.4 million. In addition, the Company requests that customer rates be reduced by a net $79.8 million through its two proposed EDIT riders and Regulatory Asset and Liability rider. As shown on Smith Second Supplemental Exhibit 2-S, the net proposed increase in revenue is $309.6 million. This is a $154.0 million reduction from the net amount proposed in the Company's Application.

If the Commission does not approve the Intervenor Settlements, the Company requests a revenue increase from base rates of $438.2 million. In addition, the Company requests that customer rates be reduced by a net $80.1

million through its two proposed EDIT riders and Regulatory Asset and Liability rider. As shown on Smith Second Supplemental Exhibit 2, the net proposed increase in revenue is $358.1 million. This is a $105.5 million reduction from the net amount proposed in the Company's Application.

Q. DOES THIS CONCLUDE YOUR SECOND SUPPLEMENTAL DIRECT TESTIMONY?

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of:	)	
	)	
Application of Duke Energy Progress, LLC For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina	)))))))	**DUKE ENERGY PROGRESS LLC'S CORRECTIONS TO THE SECOND SUPPLEMENTAL DIRECT TESTIMONY AND EXHIBITS OF KIM H. SMITH**

<u>CORRECTIONS TO THE SECOND SUPPLEMENTAL DIRECT TESTIMONY AND EXHIBITS OF WITNESS KIM H. SMITH</u>

Duke Energy Progress, LLC ("DE Progress" or "Company") provides the following Corrections to the Second Supplemental Direct Testimony and Exhibits of Kim H. Smith:

1. Since the filing on July 2, 2020, the Company has determined that Witness Kim H. Smith's Second Supplemental Direct Testimony and Exhibits contained incorrect information concerning the Excess Deferred Income Tax ("EDIT") Rider due to inadvertently amortizing the unprotected non-Property, Plant & Equipment EDIT for 20 years instead of 5 years. The following corrections to Witness Smith's second supplemental direct testimony address these changes:

    a. Page 8, Line 16 Change "$79.8 million" to "$91.0 million"

    b. Page 8, Line 19 Change "$309.6 million" to "$298.4 million" and change "$154.0 million" to "$165.2 million"

    c. Page 8, Line 23 Change "$80.1" to "$91.2"

c. Page 9, Line 3 Change "$358.1 million" to "$347.0 million" and change "$105.5 million" to "$116.6 million"

2. Replace last page of Smith Exhibit 1 Second Supplemental titled "Supplemental Changes to Op Income and Rate Base" with last page of Smith Exhibit 1 Second Supplemental Corrected.

3. Replace Smith Exhibit 2 Second Supplemental titled "Summary of Proposed Revenue Adjustments" with Smith Exhibit 2 Second Supplemental Corrected.

4. Replace last page of Smith Exhibit 1 Second Supplemental_S titled "Supplemental Changes to Op Income and Rate Base" with last page of Smith Exhibit 1 Second Supplemental_S Corrected.

5. Replace Smith Exhibit 2 Second Supplemental_S titled "Summary of Proposed Revenue Adjustments" with Smith Exhibit 2 Second Supplemental_S Corrected.

6. Replace Smith Exhibit No. 4 Second Supplemental _S Pages 1 and 2 with Smith Exhibit No. 4 Second Supplemental_S Corrected Pages 1 and 2.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of:

Application of Duke Energy Progress, LLC for Adjustments of Rates and Charges Applicable to Electric Service in North Carolina	)))))	**CORRECTED SECOND SUPPLEMENTAL DIRECT TESTIMONY OF KIM H. SMITH FOR DUKE ENERGY PROGRESS, LLC**

I. INTRODUCTION AND PURPOSE

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

A. My name is Kim H. Smith and my business address is 550 South Tryon Street, Charlotte, North Carolina. I am a Director of Rates & Regulatory Planning, employed by Duke Energy Carolinas, LLC ("DE Carolinas"), testifying on behalf of Duke Energy Progress, LLC ("DE Progress" or the "Company").

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS DOCKET?

A. Yes. I filed direct testimony and exhibits on October 30, 2019. I also filed supplemental direct testimony and exhibits on March 13, 2020, rebuttal testimony and exhibits on May 4, 2020, and settlement testimony and exhibits on June 2, 2020.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to update the Company's proposed revenue increase. An update is necessary to incorporate certain known and measurable changes through May 31, 2020. The specific items updated are identified later in my testimony.

II. UPDATES TO THE COMPANY'S TEST PERIOD OPERATING REVENUES, EXPENSES, AND RATE BASE

Q. WHAT ADJUSTMENTS TO REVENUE REQUIREMENTS ARE PROPOSED BY THE COMPANY?

A. The Company is updating its proposed revenue requirements to incorporate certain known and measurable changes to its revenues, expenses and rate base amounts previously filed in this Docket. These updates are limited, and are based on actual revenue, expense, and rate base amounts as of May 31, 2020. The updates are necessary and appropriate to provide the Company a reasonable opportunity to earn the return on equity approved by the Commission in this proceeding. Due to the extraordinary circumstances of the COVID-19 pandemic, the hearing and corresponding Commission order establishing rates in this case have been unavoidably delayed, and the Company voluntarily waived its right to implement its original proposed rates after the 270 days suspension period. Consequently, updating the Company's costs closer in time to the start of the hearing gives a more recent depiction of the Company's actual costs to serve its customers, which should be reflected in the Company's rates.

Q. WHAT OTHER ADJUSTMENTS ARE BEING PROPOSED AS A RESULT OF THE UPDATES DISCUSSED ABOVE?

A. Since the Company is updating its post-test year capital additions to reflect completed electric plant in service as of May 31, 2020, it is appropriate to also update the timing of the Company's requested deferral period for Grid Improvement Plan ("GIP") costs. The Company is requesting deferral of investments not included in this rate case. Now with the inclusion of plant in service through May 31, 2020, the Company's requested deferral of incremental GIP costs would start with plant placed in service beginning June 1, 2020 and continuing through December 31, 2022.

Q. WHAT ADDITIONAL INFORMATION IS BEING SUBMITTED IN THIS FILING?

A. DE Progress is also providing information which reflects the impact of the following settlement agreements it has entered into with intervenors (the "Intervenor Settlements"):

- Settlement Agreement with Harris Teeter, LLC filed June 8, 2020;
- Settlement Agreement with the Commercial Group filed June 9, 2020; and
- Agreement and Stipulation of Settlement with Carolina Industrial Group for Fair Utility Rates III filed June 26, 2020.

Commission approval of these agreements would result in revenue requirements based on 9.75% return on equity ("ROE") and a capital structure of 52% common equity and 48% long-term debt.

As described later in my testimony, the Company is submitting additional exhibits in this filing demonstrating the reduction to its proposed revenue increase (now based on post-test period updates through May 31, 2020) resulting from the ROE and capital structure agreed to in the Intervenor Settlements.

Q. WHICH "PRO FORMA" ADJUSTMENTS TO TEST PERIOD AMOUNTS ARE BEING UPDATED IN THIS FILING?

The following table shows the particular items revised in this filing in bold text.

ADJUSTMENTS TO OPERATING REVENUES AND EXPENSES				
Line No.	**Adjustment Title**	**Witness**	**May 2020 Update**	**ROE or Cap Str Change**
1	Annualize retail revenues for current rates	Pirro		

ADJUSTMENTS TO OPERATING REVENUES AND EXPENSES				
Line No.	**Adjustment Title**	**Witness**	**May 2020 Update**	**ROE or Cap Str Change**
2	Update fuel costs to proposed rate	McGee		
3	Normalize for weather	Pirro		
4	**Annualize revenues for customer growth**	**Pirro**	**X**	
5	Eliminate unbilled revenues	Smith		
6	Adjust for costs recovered through non-fuel riders	Smith		
7	Adjust O&M for executive compensation	Smith		
8	Annualize depreciation on year end plant balances	Smith		
9	Annualize property taxes on year end plant balances	Smith		
10	**Adjust for post-test year additions to plant in service**	**Smith**	**X**	
11	Amortize deferred environmental costs	Smith		
12	**Annualize O&M non-labor expenses**	**Smith**	**X**	
13	**Normalize O&M labor expenses**	**Smith**	**X**	
14	Update benefits costs	Smith		
15	Levelize nuclear refueling outage costs	Smith		
16	Amortize rate case costs	Smith		
17	Adjust aviation expenses	Smith		
18	Adjust for approved regulatory assets and liabilities	Smith		
19	**Adjust for merger related costs**	**Smith**	**X**	
20	Amortize severance costs	Smith		
21	Adjust for NC income tax rate change	Smith		
22	**Synchronize interest expense with end of period rate base**	**Smith**	**X**	**X**
23	**Adjust cash working capital for present revenue annualized and proposed revenue**	**Smith**	**X**	**X**
24	Adjust coal inventory	Smith		
25	Adjust credit card fees	Smith		
26	Adjust for new depreciation rates	Smith		
27	Adjust vegetation management expenses	Smith		
28	Adjust reserve for end of life nuclear costs	Smith		
29	**Update deferred balance and amortize storm costs**	**Smith**	**X**	
30	Adjust other revenue	Pirro		
31	Adjust for change in NCUC regulatory fee	Smith		

ADJUSTMENTS TO OPERATING REVENUES AND EXPENSES				
Line No.	**Adjustment Title**	**Witness**	**May 2020 Update**	**ROE or Cap Str Change**
32	Reflect retirement of Ashville Steam Generating Plant	Smith		
33	Adjust for CertainTeed payment obligation	Smith		
34	Amortize deferred balance Asheville Combined Cycle	Smith		
35	Adjust purchased power	Smith		
36	Correct Lead-Lag - Supplemental	Smith		
37	Amortize Protected EDIT – Partial Settlement	Smith		
38	Remove certain Settlement Items – Partial Settlement	Smith		
39	Normalize for storm costs – Partial Settlement	Smith		

Q. DO THE PROPOSED ADJUSTMENTS IMPACT THE AGREEMENT AND STIPULATION OF PARTIAL SETTLEMENT BETWEEN THE COMPANY AND THE PUBLIC STAFF FILED ON JUNE 2, 2020 ("PARTIAL SETTLEMENT")?

A. No. In the Partial Settlement, the Company and the Public Staff agreed to certain adjustments to the revenue requirement in the Company's rebuttal filing on May 4, 2020. The updates through May proposed in this filing are new and were not included in the Company's prior supplemental filing and therefore, were not part of the Partial Settlement with the Public Staff. However, to the extent a calculation methodology for a pro forma adjustment was agreed to in the Partial Settlement, the same methodology has been applied to the May updates.

Q. DO YOU HAVE ANY EXHIBITS TO YOUR SECOND SUPPLEMENTAL DIRECT TESTIMONY?

A. Yes. I am providing the following exhibits:

- Smith Second Supplemental Exhibit 1 corrected presents the impact of additional adjustments to test period operating income and rate base that the Company is supporting based on post-test period updates through May 31, 2020. Page 1 of the Exhibit summarizes the adjustments and the details for each adjustment presented on the subsequent pages.
- Smith Second Supplemental Exhibit 1-S corrected takes Smith Second Supplemental Exhibit 1 and layers in the additional impacts of the Intervenor Settlements – i.e., the 9.75% ROE and 52/48 capital structure.
- Smith Second Supplemental Exhibit 2 corrected summarizes the proposed total revenue adjustments in this proceeding, reflecting both the proposed increase in base rates and the net reduction in revenues reflected in the two proposed EDIT riders and the Regulatory Asset and Liability rider.
- Smith Second Supplemental Exhibit 2-S corrected takes Smith Second Supplemental Exhibit 2 corrected and layers in the additional impacts of the Intervenor Settlements – i.e., the 9.75% ROE and 52/48 capital structure.
- Smith Second Supplemental Exhibit 3 is a reconciliation of adjustments to base revenue requirement. The reconciliation begins with the $412.8 million base revenue requirement proposed by the Company in my Settlement testimony filed June 2, 2020.[1] Specific impacts related to May

[1] This amount incorporates impacts of the Agreement and Stipulation of Partial Settlement between DE Progress and the Public Staff filed on June 2, 2020.

2020 updates are itemized and summarized to show the resulting base revenue requirement of $438.2 million after May updates.

- Smith Second Supplemental Exhibit 3-S takes Smith Second Supplemental Exhibit 3 and layers in the additional impacts of the Intervenor Settlements – i.e., the 9.75% ROE and 52/48 capital structure to show the resulting base revenue requirement of $389.4 million.
- Smith Second Supplemental Exhibit 4-S corrected is an updated EDIT rider which incorporates the impacts of the Intervenor Settlements on the return component of the rider.

III. CONCLUSION

Q. DO YOUR SECOND SUPPLEMENTAL EXHIBITS REFLECT A CHANGE IN THE REVENUE REQUIREMENT SOUGHT BY THE COMPANY IN THIS PROCEEDING?

A. Yes. If the Commission approves the Intervenor Settlements, the Company requests a revenue increase from base rates of $389.4 million. In addition, the Company requests that customer rates be reduced by a net $91.0 million through its two proposed EDIT riders and Regulatory Asset and Liability rider. As shown on Smith Second Supplemental Exhibit 2-S corrected, the net proposed increase in revenue is $298.4 million. This is a $165.2 million reduction from the net amount proposed in the Company's Application.

If the Commission does not approve the Intervenor Settlements, the Company requests a revenue increase from base rates of $438.2 million. In addition, the Company requests that customer rates be reduced by a net $91.2

million through its two proposed EDIT riders and Regulatory Asset and Liability rider. As shown on Smith Second Supplemental Exhibit 2 corrected, the net proposed increase in revenue is $347.0 million. This is a $116.6 million reduction from the net amount proposed in the Company's Application.

Q. DOES THIS CONCLUDE YOUR SECOND SUPPLEMENTAL DIRECT TESTIMONY?

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-2, SUB 1219

In the Matter of:	)	
	)	
DOCKET NO. E-2, SUB 1219	)	**SECOND SETTLEMENT**
Application of Duke Energy Progress, LLC For	)	**TESTIMONY OF KIM H.**
Adjustment of Rates and Charges Applicable to	)	**SMITH FOR DUKE**
Electric Service in North Carolina	)	**ENERGY PROGRESS, LLC**
	)	

I. INTRODUCTION AND PURPOSE

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

A. My name is Kim H. Smith, and my business address is 550 South Tryon Street, Charlotte, North Carolina. I am a Director of Rates & Regulatory Planning, employed by Duke Energy Carolinas, LLC ("DE Carolinas"), testifying on behalf of Duke Energy Progress, LLC ("DE Progress" or the "Company").

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS DOCKET?

A. Yes. I filed direct testimony and exhibits on October 30, 2019. I also filed supplemental direct testimony and exhibits on March 13, 2020, rebuttal testimony and exhibits on May 4, 2020, settlement testimony and exhibits on June 2, 2020, second supplemental direct testimony and exhibits on July 2, 2020 and corrections to the second supplemental direct testimony and exhibits on July 9, 2020.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support the Second Agreement and Stipulation of Partial Settlement ("Second Partial Settlement") between the Company and the Public Staff ("Stipulating Parties"). The Second Partial Settlement was filed with the Commission on July 31, 2020.

Q. DO YOU HAVE ANY EXHIBITS TO YOUR SECOND SETTLEMENT SUPPORTING TESTIMONY?

A. Yes. I am providing the following exhibits, all of which reflect the terms of the Second Partial Settlement:

- Smith Second Settlement Exhibit 1 sets forth the operating results under current and proposed base rates.
- Smith Second Settlement Exhibit 2 summarizes the total revenue adjustments proposed in this proceeding, including the proposed increase in base rates and the net reduction in revenues reflected in the two proposed EDIT riders and the Regulatory Asset and Liability Rider.
- Smith Second Settlement Exhibit 3 is a reconciliation of adjustments to base rate revenue requirements. The exhibit begins with the revenue increase amounts shown in my Second Supplemental Exhibit 3S corrected and details the additional adjustments for which the Stipulating Parties reached agreement.
- Smith Second Settlement Exhibit 4 provides the revised computation of the NC Retail amount of EDIT refund, based on the Public Staff's recommendation of a levelized rider.

Q. WERE THESE EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes.

II. SECOND PARTIAL SETTLEMENT WITH PUBLIC STAFF

Q. DOES THE COMPANY BELIEVE THE SECOND PARTIAL SETTLEMENT REPRESENTS A BALANCED COMPROMISE THAT PROVIDES AN EQUITABLE RESOLUTION FOR CERTAIN ITEMS IN THIS PROCEEDING FOR ITS SHAREHOLDERS, CUSTOMERS AND OTHER STAKEHOLDERS?

A. Yes. As described in Witness De May's testimony, the Company believes the Second Partial Settlement with the Public Staff balances the financial impact of the rate increase on our customers with the Company's need to recover its revenue requirement, for the items included in the Second Partial Settlement, and our obligation to provide safe and reliable electric utility service to our customers.

Q. IN YOUR OPINION, DOES THE SECOND PARTIAL SETTLEMENT REFLECT A FAIR, JUST, AND REASONABLE RESOLUTION OF THE ISSUES IT ADDRESSES?

A. Yes. As stated previously, the Second Partial Settlement is the result of negotiations between the Stipulating Parties and resolves many of the issues in the case between the Stipulating Parties without the necessity of contentious litigation. Therefore, we respectfully request that the Commission approve the Partial Settlement in its entirety.

III. CONCLUSION

Q. DO YOUR SECOND SETTLEMENT EXHIBITS REFLECT A CHANGE IN THE REVENUE REQUIREMENT SOUGHT BY THE COMPANY IN THIS PROCEEDING?

A. Yes. If the Commission approves the Second Partial Settlement the Company requests a revenue increase from base rates of $409 million. In addition, the Company requests that customer rates be reduced by $147 million through its proposed riders. As shown on Smith Second Settlement Exhibit 2, the net proposed increase in revenue is $262 million. This is a $202 million reduction from the amount proposed in the Company's Application. These amounts may change based upon results from the Public Staff audit of the Company's May updates included in its July 2, 2020 second supplemental filing. The Public Staff audit is to be completed by September 15, 2020. In addition, these amounts assume the Commission accepts the Company's position on unsettled issues, thus are subject to change based on the Commission's decisions.

Q. ARE THERE OTHER CHANGES TO THE COMPANY'S APPLICATION FOR RATE INCREASE RESULTING FROM THE SECOND PARTIAL SETTLEMENT?

A. Yes. The Stipulating Parties agree that the Company will withdraw its request for deferral accounting for Grid Improvement Plan programs that are not named in the Second Partial Settlement as eligible for deferral. The Company hereby withdraws its request for deferral accounting of such programs.

Q. DOES THIS CONCLUDE YOUR SECOND SETTLEMENT TESTIMONY?

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of:	
Application of Duke Energy Progress, LLC for Adjustments of Rates and Charges Applicable to Electric Service in North Carolina	**JOINT TESTIMONY OF JAY W. OLIVER AND KIM H. SMITH IN COMPLIANCE WITH COMMISSION ORDER REQUESTING GIP INFORMATION**

I. INTRODUCTION AND PURPOSE

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

A. My name is Jay W. Oliver, and my business address is 400 South Tryon Street, Charlotte, North Carolina 28202. I am employed by Duke Energy Business Services, LLC ("DEBS") as General Manager, Grid Strategy and Asset Management Governance for Duke Energy Corporation ("Duke Energy"), the parent holding company for Duke Energy Progress, LLC ("DE Progress" or the "Company").

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS DOCKET?

A. Yes. I filed direct testimony and exhibits on October 30, 2019. I also filed rebuttal testimony and exhibits on May 4, 2020.

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

A. My name is Kim H. Smith, and my business address is 550 South Tryon Street, Charlotte, North Carolina 28202. I am a Director of Rates & Regulatory Planning, employed by Duke Energy Carolinas, LLC, testifying on behalf of DE Progress.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS DOCKET?

A. Yes. I filed direct testimony and exhibits on October 30, 2019. I also filed supplemental direct testimony and exhibits on March 13, 2020, rebuttal testimony and exhibits on May 4, 2020, settlement testimony and exhibits on June 2, 2020, second supplemental direct testimony and exhibits on July 2, 2020 and corrections to the second supplemental direct testimony and exhibits on July 9, 2020, and second settlement testimony and exhibits on July 31, 2020.

Q. WHAT IS THE PURPOSE OF YOUR JOINT TESTIMONY?

A. The purpose of our joint testimony is to respond to the Grid Improvement Plan ("GIP") portion of the Commission's July 23, 2020 *Order Requiring Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, to File Additional Testimony on Grid Improvement Plans and Coal Combustion Residual Costs* ("Order") in Docket Nos. E-7, Sub 1214 and E-2, Sub 1219. That Order, in relevant part, directs DE Progress to file certain supplemental economic analyses regarding DE Progress's proposed Grid Improvement Plan ("GIP") programs assuming, alternatively, that deferral of GIP costs is granted in one instance and denied in another. Our testimony and exhibits address this requirement and the revenue requirements computations requested by the Commission.

We also provide GIP analysis reflecting the Second Settlement and Partial Stipulation the Company entered into with the Public Staff and filed with the Commission on July 31, 2020 ("Second Partial Settlement"). The Second Partial Settlement is relevant since it includes a provision for the Company to withdraw its request for deferral accounting for certain GIP programs. Our analysis under this scenario thus shows the impact of the deferral of a smaller subset of GIP programs.

Q. PLEASE BRIEFLY DESCRIBE THE COMMISSION'S REQUEST FOR INFORMATION RELATED TO THE GRID IMPROVEMENT PLAN.

A. In its Order, the Commission requested an estimate of the North Carolina annual revenue requirement impact of the Company's GIP expenditures under two scenarios: one assuming the Company's request for an accounting deferral is granted and another assuming the Company's request for an accounting deferral is denied. The Commission also requested information on customer rate impacts under the two scenarios. The Commission provided instruction regarding a number of assumptions that are necessary to produce the requested information. Details requested include "the full impacts of the 2020-2022 GIP spending, as well as incremental operating and maintenance (O&M) costs associated with that GIP spending." Finally, the Commission ordered that the information should be "provided in spreadsheet form, with formulas intact, showing each major line item and explaining how it was calculated for each impacted year (2023, 2024, 2025, etc.), going out ten years."

II. DESCRIPTION OF SCENARIOS

Q. WITNESS OLIVER, HAS THE COMPANY PREPARED THE ANALYSES UNDER THE TWO SCENARIOS REQUESTED BY THE COMMISSION?

A. Yes. The Company has performed the analyses to the best of its ability with the information it has readily available.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY "TO THE BEST OF ITS ABILITY."

A. As previously summarized, the Commission asked the Company for a rate impact analysis under two scenarios. The first is if the requested deferral of GIP costs is granted by the Commission and DE Progress files a rate case in 2023. The Commission's Order also provides various other necessary assumptions to perform that calculation. The results of the calculation of this "Deferral Granted" scenario are reflected later in this joint testimony. In addition, as further explained by witness Smith, the Company has prepared another version of the "Deferral Granted" analysis to reflect DE Progress's Second Partial Settlement with the Public Staff.

The second analysis involves a "Deferral Denied" scenario and asks the Company to perform a similar rate impact analysis based upon any adjustment to the pace of GIP investment the Company might make based upon a denial of deferral treatment for GIP program costs. This scenario is problematic for the

Company because it would involve projecting the impacts of budget and capital management decisions that have not been made at this time and which would (and will) be influenced by a large number of factors that are not currently known.

Like any large business, Duke Energy and its subsidiary utilities go through a very involved, protracted, and iterative budgeting process on an annual basis to determine projected capital spending for the following year. This process involves the evaluation of many factors, including operational needs, customer requirements, projected revenues, projected costs, required capital expenses, cash-flows, accessibility to the debt and equity capital markets, the management of short-term and long-term borrowings and stock offerings, and maintenance of a desirable capital structure and debt ratings to name just a few. A major example of a variable that will significantly impact the Company's annual budget moving forward is the outcome of this rate case on DE Progress's financial stability and credit metrics, as explained in Company witnesses Young, Newlin and De May's testimony.

Q. HOW DOES THIS IMPACT THE COMPANY'S ABILITY TO CONDUCT THE ECONOMIC ANALYSES REQUESTED BY THE COMMISSION IN ITS ORDER FOR A "DEFERRAL DENIED" SCENARIO?

A. In multiple ways. For example, the Company has not performed a budget analysis for the "Deferral Denied" scenario requested by the Commission so it cannot predict with any degree of certainty how much it would scale back GIP spending if deferred asset treatment is denied in the pending rate case. Those decisions will ultimately be made by management on an annual basis following the normal budgeting process by the Company. Nevertheless, I can say that the Company will likely delay significant portions of its intended GIP spending if all or a portion of accounting deferral treatment is denied. Without a reasonable means of mitigating the negative impacts of regulatory lag associated with significant ongoing and incremental spending under the GIP, the Company would be required to reassess its ability to commit to the planned level of investment in this program given that the level of investment anticipated under the plan simply cannot be reasonably sustained in the absence of mitigation measures such as the deferral requested herein. As such, if the Commission determines not to grant the accounting deferral treatment for all or a portion of the Company's GIP investment sought in this proceeding, the Company will likely be in a scenario where its level of GIP investment will vary significantly from year to year as it prioritizes and reprioritizes work to meet its capital plan. In such a situation, the Company would have to perform smaller pieces of the GIP over a much longer timeframe with its existing revenues, which would delay important benefits for customers.

Simply put, to perform the work identified in the GIP at the pace and scope that provides the most benefit for customers, the Company needs new and modern ways to recover costs and avoid the regulatory lag that can harm the Company's financial metrics which, in turn, can harm customers. While critical to the modernization of the grid, without deferral (or some other alternative ratemaking treatment), the Company's GIP investments would need to compete annually for the same capital as base work, much of which is mandatory (*e.g.*, replacing failed equipment, providing service to new customers, or to meet a regulatory requirement). Because capital funding is dependent on multiple variables, some of which have been previously mentioned, the Company's ability to forecast future GIP investments without a deferral is limited.

Q. ARE THERE OTHER FACTORS THAT MAKE THE "DEFERRAL DENIED" RATE IMPACT ANALYSIS IMPOSSIBLE TO PROVIDE AT THIS POINT IN TIME?

A. Yes. For the reasons described in witnesses Young, Newlin and De May's rebuttal testimony, the Company cannot know what its revenues for the requested period will be because the determination of what those revenues will be for future periods is largely tied up in this case and will also be impacted by the economic environment, which is further exacerbated by the ongoing COVID-19 pandemic. Even a cursory examination of the differences in position of the Company and intervenors reveals a difference in proposed possible outcomes that varies by hundreds of millions of dollars. Without having a reasonable approximation of what our revenues will be for the designated period, it is literally impossible to calculate prospective cash-flows or available capital for investment in GIP programs. A similar situation persists with our costs for the designated period. The Company cannot be confident in its costs for 2021 or 2022 at this point in time and does not have enough contextual information (and will not have that information for some time) to project what funds will be available to support GIP investment in the last two years of the period specified.

Q. ARE YOU TELLING THE COMMISSION THAT YOU CANNOT PROVIDE THE SECOND "DEFERRAL DENIED" ECONOMIC ANALYSES THEY REQUESTED?

A. No. What I am saying is that we do not have the information necessary to provide the requested "Deferral Denied" analysis exactly as it would play out in reality because there are too many unknown variables. What we can and have provided, however, is a hypothetical analysis showing comparative rate impacts of the "Deferral Denied" scenario based upon an assumption that DE Progress would reduce its original projected GIP spending by a factor of 80 percent. In order to avoid overly complicated calculations, in a short period of time, that result from trying to adjust the hypothetical to the status of the pending case, our hypothetical assumes GIP spending reduced by 80 percent for a period of three years at the end of which DE Progress files a rate case. The Company selected 80 percent to represent the myriad of aforementioned variables impacting decisions to invest in GIP expenditures on an annual basis. This hypothetical corresponds to the timing involved in the "Deferral Granted" analysis.

Q. WHAT ASSUMPTIONS ARE BUILT INTO THE HYPOTHETICAL "DEFERRAL DENIED" SCENARIO?

A. The assumptions we used in conducting this analysis are explained later in this joint testimony and in the exhibits attached hereto.

Q. DO THESE ASSUMPTIONS REFLECT REALITY?

A. Probably not. For example, the rate impact analysis for the "Deferral Denied" scenario is based on a 10.3% return on common equity ("ROE") and a 53% equity to 47% debt ratio, as originally proposed in our Application, and as directed by the Commission. However, given the Company's settlements with several parties in this case, including the Public Staff, on issues including ROE and cap structure, the Company expects the final, authorized ROE by this Commission to be lower than 10.3%. Furthermore, there are simply too many factors that are unknown to the Company at this time that are likely to vary from our assumptions in the "Deferral Denied" analysis. For example, the Company has no definite plans to file a rate case in 2023. The Company may file before or after that timeframe, or both. So while the Company has conducted a "Deferral Denied" analyses for purposes of the Commission's Order, it is purely hypothetical in nature.

Q. DO YOU HAVE ANY OTHER THOUGHTS ABOUT THE HYPOTHETICAL ANALYSIS PROVIDED BY WITNESS SMITH?

A. Yes. The analyses presented by witness Smith represent a good faith attempt by the Company to provide comparative information that may be useful to the Commission in its evaluation of our GIP proposals, but I want to emphasize that a probative analysis would require a large and diverse set of assumptions about virtually every aspect of DE Progress's economic performance over the next several years. Accordingly, given so many economic uncertainties, we maintain that this analysis likely does not reflect decisions the Company will actually make during the period 2020-2023.

Q. IF DE PROGRESS DOES FILE A RATE CASE IN 2023, WOULD YOU EXPECT THE RESULTS OF THE "DEFERRAL DENIED" ANALYSIS TO REFLECT WHAT ACTUALLY HAPPENED BETWEEN NOW AND THAT RATE CASE?

A. No. Again, the Company cannot currently know what factors will influence its capital budgeting and investment practices over the next three years. And given that its hypothetical is just that, it is not reasonable or rational to believe it will be reflective of reality during the next three years. Most importantly, it is not designed to serve that function. We developed it solely to try to provide, as best we could, a basis for comparing the first scenario, where deferred accounting treatment is allowed, to a situation where deferral accounting was denied for GIP spending in accordance with the Commission's Order.

III. THE COMPANY'S ANALYSES

Q. MS. SMITH, CAN YOU PLEASE DESCRIBE THE EXHIBITS TO THE JOINT TESTIMONY?

A. We provide an exhibit for each scenario requested by the Commission: GIP Exhibit 1 – Deferral Granted and GIP Exhibit 2 – Deferral Denied. These exhibits are based on the Company's original request for deferral of GIP related costs pursuant to DE Progress's Application in this docket.

We have also provided additional analyses showing what the first scenario (Deferral Granted) would look like if the Commission were to approve the Second Partial Settlement: GIP Exhibit 3 – Deferral Granted (Settlement). This exhibit reflects the terms of the Second Partial Settlement, in which the Company has agreed to withdraw its request for deferral of costs related to certain GIP programs, resulting in a deferral request that is more limited than originally proposed.

Q. HOW ARE THE EXHIBITS ORGANIZED?

A. Each exhibit contains five pages, which show the results of the spreadsheet calculations performed to comply with the Commission Order. Each exhibit contains the following items:

Page 1 – Rate impacts by customer class

Page 2 – Income statement and rate base amounts – 10 years

Page 3 – Revenue requirements – 10 years

Page 4 – Assumptions

Page 5 – Summary of deferred amounts

The Excel spreadsheets provided, with formulas intact, include detail workpapers that support the filed exhibits.

Q. MS. SMITH, WERE THESE EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes.

A. Deferral Request is Granted

Q. PLEASE DESCRIBE THE GENERAL APPROACH TO COMPUTING THE MONTHLY REVENUE REQUIREMENTS IF GRANTED DEFERRAL OF GIP COSTS.

A. The Company started with the estimated GIP program expenditures for years 2020, 2021, and 2022. The Company estimated when amounts spent would result in completed electric plant-in-service, *i.e.*, the length of the construction period. Monthly revenue requirements were computed for completed plant in service amounts, beginning the first month that the plant is in service. Revenue requirements include depreciation, return on net plant investment, installation O&M, and property taxes. The monthly revenue requirements were computed for electric plant in service added from January 2020 through December 2022. It was assumed that each month's revenue requirement was deferred as a regulatory asset, and a monthly return (*i.e.*, carrying cost) was accrued on the deferred asset balance.

Next, rate case timing was considered. As instructed by the Commission, we were to assume that a rate case would occur in 2023. Accordingly, we assumed that the test period would be calendar year 2022, and new rates would be effective January 1, 2024. During the period January through December 2023, before new rates would become effective, the Company assumed it would continue to defer the monthly revenue requirements on the completed plant in service as of December 31, 2022.

As a result, giving consideration to rate case timing, the deferred GIP amounts reflect the monthly revenue requirements for the period January 2020 through December 2023, for completed GIP plant in service as of December 31, 2022.

Q. PLEASE DESCRIBE HOW YOU DETERMINED THE RECOVERY OF THE DEFERRED AMOUNTS IN A GENERAL RATE CASE.

A. In an assumed 2023 general rate case, the Company would seek recovery of the balance of deferred costs, amortized over a period of time proposed by the Company. This deferred balance represents the revenue requirement amount associated with the GIP investments during the period January 1, 2020 through December 31, 2023, that has not yet been reflected in rates, and therefore funded by investors.

To comply with the Commission's request, the Company must assume an amortization period. In a traditional general rate case, the selection of an amortization period would be determined based on a number of factors. For purposes of providing the information requested by the Commission, the Company has assumed an amortization period of five years. A longer amortization period would produce a lower annual rate impact of the deferral and a short amortization period would result in a higher annual rate impact.

In addition, in the general rate case, the ongoing revenue requirements associated with the GIP investments would be incorporated into future rates, since the test period operating expenses and rate base would include the GIP investments in service at the end of test period. The calculations assume that at the end of the five-year amortization period, base rates are reset to remove the recovery of the deferred GIP costs, and the on-going revenue requirements remain in base rates.

Q. WHAT ASSUMPTIONS DID YOU USE FOR ROE, CAPITAL STRUCTURE, AND COST ALLOCATION?

A. For purposes of calculating revenue requirements under the two scenarios, the Commission asks the Company to "use the return on common equity, capital structure, and cost allocation methodology that each Company has advocated in the present rate case dockets." The Company interprets the Commission's request to mean that it should use the positions on these items as advocated in its Application. In order to simplify the analyses, we are using the ROE, capital structure, and cost allocations included in the Company's Application as a proxy for all periods included in the analyses. The ROE, capital structure, and cost allocations that will be approved in this case are not the same as the ROE, capital structure, and cost allocations currently approved nor are they necessarily going to be the same as the ROE, capital structure, and cost allocation methodology approved in a future rate case.

B. Deferral Request is Denied

Q. PLEASE DESCRIBE THE GENERAL APPROACH TO COMPUTING THE MONTHLY REVENUE REQUIREMENTS IF DENIED DEFERRAL OF GIP COSTS.

A. The calculations prepared by DE Progress in response to the scenario in which the Company's request for deferral accounting is denied are identical to the calculations for the scenario in which a deferral is granted except estimated GIP expenditures are reduced and no deferral is assumed. Under the denial scenario, the original GIP expenditures are reduced by 80%. This assumption is explained above by witness Oliver.

The exhibits presented are the same as for the "Deferral Granted" scenario. A separate Excel file with the exhibits and workpapers is provided.

C. Deferral is Granted and Second Partial Settlement is Approved

Q. PLEASE DESCRIBE THE ADDITIONAL SCENARIO PROVIDED BASED ON THE SECOND PARTIAL SETTLEMENT.

A. Subsequent to the Commission's Order in this docket requesting these calculations, the Company and the Public Staff filed their Second Partial Settlement with the Commission, in which the Company agreed to withdraw its request for an accounting deferral for certain GIP programs, but retain its deferral request for specific programs for which deferral is supported by the Public Staff and other intervenors. As a result, the Company is providing an additional scenario assuming deferral of the costs for only those programs for which the Company request an accounting deferral under the terms of the Second Partial Settlement. This scenario includes deferral of GIP costs related to completed plant in service beginning June 2020. Amounts related to GIP completed plant in service for January through May 2020 are incorporated in the Company's proposed revenue increase in this docket.

Q. ARE THE CALCULATIONS PREPARED UNDER THE SETTLEMENT SCENARIO THE SAME AS FOR THE SCENARIOS REQUESTED BY THE COMMISSION?

A. The data provided and the underlying computations are the same, but the amount of GIP expenditures subject to deferral is reduced from the Company's "Deferral Granted" scenario based on the terms of the Second Partial Settlement. In addition, this exhibit also reflects the 9.6% ROE and 52% equity and 48% debt capital structure included in the Second Partial Settlement. For purposes of this exhibit, we are using the settled ROE and capital structure as a proxy for all periods included in the analyses. The ROE and capital structure that will be approved in this rate case are not the same as the ROE and capital structure currently approved nor are they necessarily going to be the same as the ROE and capital structure approved in a future rate case.

Q. DO YOU HAVE ANY OTHER COMMENTS ON THE SCENARIOS?

A. Yes. These scenarios contain several assumptions and should not be interpreted as a guarantee of what future rate impacts will be under any of the scenarios. For example, in allocating the costs to the customer classes, an allocator was developed based on the test year distribution plant in this rate case, using the allocation methodologies proposed in this rate case. When the next rate case is filed, distribution investments in the new test period may vary from the allocations used in these scenarios. In addition, as discussed previously, assumptions were made around rate case timing, cost of capital, and in-service dates of capital spend. Any changes in these factors, or changes in other factors (tax rates, other rate changes, etc.), will impact the ultimate rates for customers.

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR JOINT TESTIMONY?

A. Yes.

Duke Energy Progress, LLC
Summary of Testimony of Kim H. Smith
Docket No. E-2, Sub 1219

I am the witness who supports Duke Energy Progress's requested revenue requirement, pro forma adjustments, and various accounting requests. As a result of the settlement agreements the Company has entered into with the Public Staff and other intervenors, the majority of revenue requirements issues have been resolved, pending Commission approval. The most significant issue still in dispute that is covered in my testimony is the appropriate ratemaking treatment for the Company's coal ash compliance costs.

The particular coal ash-related costs at issue are the costs incurred by the Company in connection with its coal ash basin closure activities from September 1, 2017 through February 29, 2020. All of these costs were incurred due to a change in the law that required the Company to manage coal ash differently than it had done in the past, and to retire long-lived assets that the Company had been using for purposes of coal ash management and storage. The costs are accounted for in AROs as explained by Company witnesses Riley and Doss. These costs have been deferred in accordance with the Commission's order in the Company's previous rate case, decided in February 2018. In the current case, the Company proposes a five-year amortization period, along with inclusion of the unamortized deferred balance in rate base – identical to the treatment approved and ordered by the Commission in the Company's previous rate case. Inclusion of the unamortized balance in rate base of course means that the Company would earn a return on that balance at its weighted average cost of capital during the amortization period. This is precisely what the Commission ordered in the prior case.

In this case, the Public Staff again proposes a lengthy amortization period for recovery of deferred coal ash costs and a disallowance of a return on the unamortized balance in order to achieve what it calls an "equitable sharing" between customers and shareholders. The Public Staff's "equitable sharing" adjustment runs directly contrary to well-established ratemaking and cost recovery principles and, in particular, the basic principle that a public utility's reasonable and prudently incurred costs are recoverable in rates. The Commission has rejected Public Staff's arbitrary approach on at least four occasions and should do so again in this case.

The Public Staff's proposal acknowledges that financing costs during the initial period of deferral – that is, from the time the costs are incurred until they are brought into rates – should include the Company's financing costs. It is during the period over which the costs are amortized after being brought into rates that the Public Staff indicates no financing costs should be allowed. This runs contrary to well established ratemaking and cost recovery principles.

The costs at issue include the cost of money. The financing costs related to funds advanced by investors are no less costs associated with the provision of service to customers than the depreciation, O&M, or other costs of the power plants that generate electricity or the towers, poles, and lines that transmit and distribute that electricity to customers' homes and businesses. None of the costs at issue have previously been brought into rates and paid for by customers. All of these costs have been funded by investors. Because the costs are wholly financed by the Company and its investors, the Public Staff appropriately recognizes that the Company's financing costs during the deferral period are legitimately incurred and recoverable. That same principle applies during the amortization period as well.

As the Commission found in Duke Energy Carolinas' 2017 rate case, "if in the process of bringing the deferred costs into rates the costs are amortized over a period of years, not allowing a return on the unamortized costs again impairs the Company's ability to earn at its authorized rate of return." The Commission concluded that denying DEC the opportunity to earn its allowed rate of return on prudently incurred costs results in rates that are unjust and unreasonable. The same conclusion continues to hold today and is equally true for Duke Energy Progress.

Duke Energy Progress, LLC
Summary of Testimony of Kim H. Smith
Docket No. E-2, Sub 1219

I am aware that the Commission came to a different conclusion in its Order in Dominion North Carolina's most recent rate case, based on the evidence and record in that case, although I am not completely familiar with that record. However, the record on this issue for Duke Energy Progress was fully developed in the Company's previous rate case, and the evidence presented in the current case is no different from the evidence in the prior case.

In its prior rate case, the Company had requested a "run rate" to collect at least a portion of ongoing coal ash basin closure costs, which would have shifted the funding source for those costs from the Company and its investors to customers. The Commission rejected the Company's proposal. Noting that the Company had requested – and that the Commission had approved – deferral of the costs into an ARO, the Commission indicated that the Company had therefore conceded that treating coal ash basin closure costs as recurring test year expense was inadequate. The Commission held instead, and I quote:

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

The costs referenced in the 2018 order are the costs that are at issue now in this rate case. The Commission's direction seems clear to me, and the Company has done what it was ordered to do – it has raised the money to fund its ongoing coal ash costs from its investors, and now seeks recovery of those costs. The costs include the cost of money, as this Commission recognized in the 2018 Order.

This concludes my summary.

COMMISSIONER CLODFELTER: Ms. Smith, your video has been cutting in and out on us. I'm not sure what is there. But your audio seems to be okay, but your video seems to be coming and going.

THE WITNESS: I know. It seems every time I hit my spacebar, my video has been going out. I'm not sure why, I'm sorry.

COMMISSIONER CLODFELTER: All right. Ms. Jagannathan, proceed.

MS. JAGANNATHAN: Thank you.

Q. And because you obviously are a different witness than Ms. McManeus, I'm just going to ask you a couple of foundational questions before we go ahead and work through the stipulation.

So, Ms. Smith, did you watch Jane McManeus testify during the DEC hearing?

A. Yes, I did.

Q. And did you have the opportunity to review the transcript of her live testimony during the DEC-specific hearing?

A. Yes, I did.

Q. And do you agree with the answers Ms. McManeus gave during that live testimony?

A. Yes, I do.

Q. And you would have no objection to her answers to the questions she was asked during the hearing being copied into the record as if you gave them orally from the stand; is that right?

A. That's correct.

MS. JAGANNATHAN: Okay. Commissioner Clodfelter, pursuant to the joint stipulation of live testimony and exhibits of Jane L. McManeus, which was entered into between Duke Energy Progress and the Attorney General's Office, and filed with the Commission on September 25, 2020, I would move that the live testimony of DEC witness Jane McManeus in Docket Number E-7, Sub 1214, be copied into the record in this proceeding as if given orally from the stand by DEP witness Kim Smith. And the applicable testimony is located in transcript Volume 15, page 125, line 23 through page 149, line 13, and continuing on page 154, line 19 through page 160, line 7.

COMMISSIONER CLODFELTER: All right. You've heard the motion. Are there any objections to the motion?

(No response.)

COMMISSIONER CLODFELTER: Hearing none, the motion is allowed.

(Whereupon, the Testimony from Docket Number E-7, Sub 1214 Transcript Volume 15, page 125, line 23 through page 149, line 13; and transcript Volume 15, page 154, line 19 through page 160, line 7 were copied into the record as if given orally from the stand.)

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CROSS EXAMINATION BY MS. FORCE:

Q. Good afternoon, Ms. McManeus and Mr. Speros.

My name is Margaret Force with the Attorney General's Office, and I think most of my questions, or all of them are directed to Ms. McManeus as well.

A. (Jane L. McManeus) Okay.

Q. I'd like to run through some numbers that relate to the coal ash cost recovery that's addressed in this case.

And I believe that, Ms. McManeus, I'm looking mostly at your testimony, the supplemental testimony that you filed. And that would be on page 3, you indicate that the adjustment for what you called deferred environmental cost is number 11; isn't that right?

A. I filed a lot of testimony. Could you repeat for me so I can look at it? I have my direct, and then I have a supplemental, and then rebuttal. So do you mean my first supplemental?

Q. I do. And that's dated February 14, 2020.

A. And I'm sorry, what page again?

Q. Page 3.

A. (Witness peruses document.)

Okay. I'm at page 3. And on page 3, I see a list of adjustments.

Q. I am referring to number 11, which is the adjustment that you've made for deferred environmental costs. And I believe that refers to the cost associated with coal ash; is that right?

A. Yes, that is correct.

Q. And I could ask you -- I think it would be useful for you to take a look at your Exhibit 1 that you filed with your supplemental testimony, so the same date, February 14th. And you have identified labels on the coal ash in categories that are called ARO and non-ARO, where ARO refers to the removal of coal ash or closure of ash ponds, and the non-ARO part addresses ongoing operations at operating plants, like dry ash handling and water treatment; does that sound right?

A. That's right. I did separate it into two categories.

Q. So if you'd look at your supplemental Exhibit 1, the updates to work papers that were filed in E-1, Item 10, appear on page 55 of that exhibit, if you'd look there.

A. Ms. Force, I don't have in front of me that particular detail in my Exhibit 1. I have in front of me what my final exhibit looked like for coal ash.

Q. Well --

A. Let me --

Q. I looked at -- let me ask you this: When I'm looking at that supplemental testimony, it relates to actual costs, as I understood it, during the deferral period; is that right?

A. That's right. And I think that we're -- the one I'm looking at is probably identical to what you're looking at. So what we did is included in this adjustment the recovery of the coal ash costs that were incurred January of 2018 through January of 2020, and that's what you've recently heard Ms. Bednarcik testify to.

Q. And when you talk about those numbers, you're talking about the expenditures in each of those months through the end of January 2020, right?

A. That's correct.

Q. So if you look at that number, then -- our numbers may be a little bit different because of adjustments that you've made for rate of return, but I just want to run through and get some of the basics down.

When you look at that period, we're talking about 25 months, and the -- and I think we just said, the further updates don't add months to it, but they do increase the amount for what you call the carrying costs in some places, the rate of return; is that right?

A. That's correct. We did not add any actual coal ash expenditures beyond January 2020, but we do show the additional carrying costs through July of '20.

Q. That would be the end of July. And when was it that the temporary rates took effect?

A. We had originally expected rates to be effective August 1, but the temporary rates went into effect mid-August, so there's a little gap in between the end in this pro forma adjustment and what actually happened. So there are some financing costs that were not captured.

Q. Okay. So I'm looking on page 57 of the supplemental exhibit. I'm hoping it's in the same place as yours is. I see that the -- and the amount should be the same -- well, it's close to the same. Roughly $378.464 million as the total amount that you're talking about for the closure of ash ponds, including the rate of return during the deferral period; does that sound right?

A. That's correct.

Q. And in my document, that's the sum of $341.568 million plus $36.806 million, and the

$36.806 million relates to the carrying costs during the deferral period; is that right?

A. That's correct.

Q. So the period of time that Duke was carrying those expenditure costs was roughly two and a half years or 32 months at the longest time, but those carrying costs apply as the expenditures were made.

So a lot of those expenditures were just made under 18 months ago; is that right?

A. Yes. The expenditures were made over that time period that you described. So some of them as early as January of 2018, and then the later ones, January of 2020. And the Company still incurs financing costs on those amounts that have been advanced by investors.

Q. And the rate of return that's used is the rate of return from the last rate case reflecting the rate of return on equity that was approved in the return on long-term debt; is that right?

A. Yes, that's correct.

Q. Okay. So now let's identify the amount that Duke proposes to include in the cost of service, or the annual revenue requirement in the case.

Would you agree with me that the amount is

$75.7 million?

A. The revenue requirement is actually made up of two components. It's made up of the amortization, and then it's made up of a return on the unamortized balance. And I think, in total, that amount is about $96 million, and the amortization piece of it is around -- now -- (sound cut off). Sorry. I'm talking about the total including the -- I'm just -- I'm sorry. I'm simply speaking of the ARO amount.

Q. That's what I was talking about. And is it -- for the amount that's amortized each year, separating from the amount that shows up in the proposal for rate base, what was the amount you said?

A. It's about $76 million.

Q. And then when you include the amount that's being amortized, would you say that that comes out, the two together -- well, that that rate of return amount would be about $16.3 million?

A. I'm sorry, I don't have that piece of paper in front of me, but the total is $96 million. So it's about $20 million.

Q. Okay. So $96 million is the amount for the defer -- the amount that's been deferred in this period January 1st of 2018 through January 31st of 2020, then, that's being proposed by Duke in this case, right?

A. I would see it slightly differently. The revenue requirement associated with the amount that's deferred and brought forward in this rate case is about $96 million.

Q. Okay. Now, is it also true that Duke is still amortizing the coal ash costs from the last rate case?

A. Yes, it is true.

Q. And is the amount of that roughly 110- to $120 million per year reflected in the revenue requirement?

A. It's about $120 million.

Q. So together, the amount is over $200 million per year that will be recovered in the revenue requirement related to coal ash under Duke's proposal in the case; is that right?

A. I would say that differently again. I would say that existing rates already includes an amount, and then if the Commission approves the request of the Company, then in customers' rates would be a total of around the $200 million that you're stating.

Q. It's a little more than that, it sounds like --

CHAIR MITCHELL: Ms. Force, I'm going to interrupt you. For purposes of the record, would you please just classify which document you're looking at.

MS. FORCE: Sure. We're actually looking at little different documents, but I can refer you specifically to McManeus Supplemental Exhibit 1, which is part of her testimony that was filed. It's the exhibit to her testimony filed February 14, 2020, and I started with page 55 of that exhibit.

THE WITNESS: And I'm looking at that as well.

Q. And to further clarify, would you agree with me, Ms. McManeus, that the amount of deferral hasn't changed since that supplemental testimony was filed, but the amount of the rate of return that's applied to it has changed?

A. Yes.

MS. FORCE: Does that clarify it for you, Chair Mitchell?

CHAIR MITCHELL: Yes. Thank you, Ms. Force.

Q. We were talking about --

A. I'm sorry -- I'm sorry, Ms. Force. I need to perhaps elaborate a little bit more. The coal ash recovery is one that is, you know, not settled upon. And so ultimately the exact revenue requirement will be determined when the Commission does render its opinion about what the appropriate return on rate base will be.

Q. Yes. And I didn't mean to confuse the record.

So when you talked about $96 million, do you remember what the rate of return was that you were using in that calculation?

A. (Witness peruses document.)

Q. It would be more helpful to ask it this way.

That the amount of rate of return is from the last rate case, isn't it, that we used to calculate up through the period of deferral?

A. Yes, it was, in my supplemental file.

Q. But when we calculate the amount on the rate base going forward, would that be an amount that's calculated based on the rate of return that the Commission fixes in this case?

A. Yes, it is.

Q. Those numbers may adjust somewhat depending on the final outcome in the case, correct?

A. Yes.
Q. But roughly speaking, would you agree with me that we're talking about over $200 million per year that would be recovered through rates for coal ash cost?
A. Yes. I would agree that, if I look at what customers are paying in existing rates, as well as what the Company is proposing that customers pay, it would be over $200 million. About 120 in the existing, and about 96 in the currently proposed; and that adds up to more than -- a little more than $200 million.
Q. So I know costs won't be distributed that way for customers, but Duke Carolinas has about two million customers, so it's going to be about $100 per year per customer, just roughly?
A. I don't have a calculation of -- like, my calculation is really sort of a percent impact on customer bills, and like what is being proposed in this case is a 2 percent average increase for North Carolina retail customers; but I did not -- that average is different among customer classes, and I didn't compute an amount per customer bill.
Q. That's fine. We can move on. I have a few questions for you that are more general accounting

principles for ratemaking.

Can you agree with me that the accounting exhibits that you prepared show Duke's position about the annual revenue requirement needed to meet the costs providing electric service to retail customers after rates are set going forward?

A. Yes. The purpose of my Exhibit 1 is to identify the annual revenue requirement that the Company needs to provide electric service.

Q. And in order to estimate what that cost of service is, then you prepare exhibits that show costs in a test year with a number of adjustments to that; is that right?

A. Yes. In the state of North Carolina, we are in a historical test period state, so we start with historical actuals. And then to the extent that those amounts would not be representative of the Company's revenues and expenses in the future, then we are allowed to make certain pro forma adjustments to make them more representative of the future.

Q. So would you agree with me that some of the adjustments normalize costs?

A. That's correct. Some of the adjustments normalize costs.

Q. For example, there's an exhibit in your adjustments for making an adjustment to normalize for variations and weather; is that right, on how much electricity might be used?

A. That's correct.

Q. And you might make adjustments to annualize costs, say if a cost started in March or June, so that you are representing what the costs would be over the course of the full year; am I understanding annualized correctly?

A. Yes, that's correct.

Q. And if you had made expenditures in 2018 for the construction of a new power plant, for instance, those expenditures wouldn't show up in the month that they were incurred as an operating expense for the Company that would be expected going forward, would they? They'd be capitalized?

A. Yes. If you're speaking of a generating plant, you have a construction period. The expenditures are being financed by investors, and from an accounting perspective, following either GAAP or FERC accounting, they would be capitalized.

Q. And expenditures on long-term assets are not recovered in the month that the expenditures are made,

but they rather are recovered in rates over the useful life of the assets, right?
A. Yes. The Company recovers those amounts by depreciating the assets over their estimated service life, and recovers that depreciation as well as the return on the unrecovered balance.
Q. And when -- so to restate that a little bit, the full amount of an expenditure for an addition to plan, which will be used in rendering service over a long period of time, should not be charged to customers who use the service in the month of such expenditure, but is spread over the anticipated life of the equipment, right?
A. That's traditionally what is done to recover the cost of a generating plant. And I think you're correct that, rather than recover it all in one period, usually the ratemaking treatment is to recover it over its life through depreciation expense.
Q. And can you agree with me that this is a recognition of the principles that the users in each period should be charged with a cost of service attributable to that period?
A. Yes. I would say that that is an underlying principle. I would also note that, on occasion, that's

not always possible.

Q. So are you talking about an exception to the general rule, then?

A. Yes. I'm -- when I said "on occasion," I meant that it's not always, but on occasion that is not the case.

Q. And just as an another example, there are rate case expenses that are probably going to be included in this case, and those expenses are not reflected as an annual amount, but rather would be spread over the anticipated time between rate cases so that it -- I guess you would call that normalizing the amount; is that correct?

A. Yes. There are certain costs that are captured and spread over multiple periods of time in an attempt to normalize.

Q. Okay. Now, just asking a couple more questions along these lines, this is pretty general, but there are also quite a few adjustments that are made to address the fact that Duke Carolinas serves in both North and South Carolina and serves both retail and wholesale customers, right?

A. I'm not sure what you mean by "adjustments." I think if you look at my Exhibit 1, it starts out with total Company amounts, and then, through cost of service, one would allocate or assign amounts to North Carolina retail jurisdiction, which by definition assumes that some other rate jurisdictions would also be assigned or allocated a portion of those system amounts.

Q. And in many cases, those costs are -- where they're joint costs, are approximated, right? They're not exactly this part goes to North Carolina, this part goes to South Carolina; there has to be some sort of an allocation process that's an approximation; am I right?

A. I'm not really sure if I would call it an approximation. I imagine you heard witness Hager speak extensively about cost of service and the underlying principles behind it and cost causation principles. And, obviously, we don't do cost of service on a customer-by-customer basis. We have to group them similarly. And so yes, they're -- they are allocated because we don't -- because we cannot do cost of service by individual customer.

Q. Okay. I won't continue with that, Ms. McManeus, you're right, there are other folks who speak to cost of service.

I'd ask you now to please turn -- I want to go through a few documents with you to get them into the record, and I'm not going to spend a lot of time with the documents. But if you'd turn, please, to AGO Exhibit 43.

A. (Witness peruses document.)

Q. And that is a document with Duke Energy at the top, and it has the date, December 30, 2016.

A. Okay. I have this document now.

MS. FORCE: So I'd ask that this document be marked AGO McManeus Speros Cross Exhibit 1, please.

CHAIR MITCHELL: The document will be so marked.

(AGO McManeus/Speros Cross Exhibit 1 was marked for identification.)

MS. FORCE: Thank you, Chair Mitchell.

Q. Can you agree with me, after you look at this, Ms. McManeus, that this is a petition -- the petition that was filed by Duke on December 30, 2016, for an accounting order to defer environmental compliance costs in the Dockets E-7, Sub 1110, and E-2, Sub 1103?

A. Yes, that's what this is.

Q. You included a cover letter with that, that if you look at page 2 of the petition --

(Reporter interruption due to sound failure.)

CHAIR MITCHELL: Ms. Force, we've now lost -- there are you. You're back.

MS. FORCE: I'm sorry. I had to move the book, I think, because I'm turning away from the mic. So I turned the mic on and I'll try to remember to turn it off so we don't interfere with each other.

Q. But if you look on page 2, it says on that second full paragraph:

"Closing ash basins is part of the lifecycle of the Company's coal plants and compliance with state and federal regulatory requirements as part of the normal operation of the utility."

Would you agree with me that that's what is stated there?

A. Yes, I agree.

Q. And this is Duke's petition requesting that the costs be deferred for recovery in some future proceeding; is that right?

A. Yes, that's correct. This was our petition, which was consolidated into the previous rate case and ruled on by the Commission in that case granting the deferral.

Q. And it could also be -- I'm sorry.

Within that document, on page 9, there's a reference to an order that was issued by the Commission in E-7 -- Docket Number E-7, Sub 723, dated August 8, 2003; do you see that?

A. Yes, I do.

Q. And I have that exhibit, and we can either ask the Commission to take judicial notice of it or that -- I have that as AGO Exhibit 40. If you want to take a look at that, you'll see.

A. Ms. Force, I would just note to you -- I have Exhibit 40 here. But I would just note to you that you are starting to ask me some questions that are covered in the testimony of one of our other witnesses, Mr. Doss.

Q. That's fine. I'm not going to ask you very many questions, I'll just get these into the record. The documents speak for themselves.

A. Okay.

Q. Would you agree -- this says -- what's been prefiled as AGO Exhibit 40 is that E-7, Sub 723, order from the Commission; would you agree with that?

A. That's what Exhibit 40 is, yes.
Q. Okay.
MS. FORCE: And just for clarification in the record, I'd ask to mark this as AGO McManeus/Speros Cross Exhibit 2.
CHAIR MITCHELL: All right. Hearing no objection to your motion, it's allowed.
MS. FORCE: Okay. Thank you.
(AGO McManeus/Speros Cross Exhibit 2 marked for identification.)
Q. And then I would ask you to turn to AGO Exhibit 41, please. Do you have that?
A. Yes, I see it.
Q. Okay. Just -- I'm looking -- what I'm looking at is comments to the Attorney General's Office in those same subdoc -- the petition for accounting order, that's E-2, Sub 1103, and E-7, Sub 1110; can you agree with me to that?
A. Yes. That's what your Exhibit 41 is.
MS. FORCE: And I'd ask to mark this as AGO McManeus/Speros Cross Exhibit 3, please.
CHAIR MITCHELL: Hearing no objection, the document will be so marked.
(AGO McManeus/Speros Cross Exhibit 3 was

marked for identification.)

Q. And one more. If you'll turn to 42 -- AGO 42, please. That's dated -- it's a Duke Energy letterhead dated April 19, 2017; do you see that?

A. Yes, I do.

Q. Okay.

MS. FORCE: I'd ask to mark this as AGO McManeus/Speros Cross Exhibit 4, please.

CHAIR MITCHELL: All right. The document will be so marked.

(AGO McManeus/Speros Cross Exhibit 4 was marked for identification.)

Q. And can you agree with me that these are Duke's reply comments in that accounting docket that, as you said, was consolidated into the last rate case?

A. Yes. These are Duke's reply comments.

Q. Okay. Thank you. All right. So I have another question for you, and it involves the exhibit -- AGO Exhibit 28.

A. (Witness peruses document.)

Q. Are you there?

A. Okay. I see it.

Q. Good. Okay. And I -- if you'll take a look at this, does it appear to you to be a Duke Energy response to a data request from the Attorney General's Office in Docket Number E-7, Sub 1146?

A. Yes, it is.

Q. Okay.

MS. FORCE: I would ask that this be marked as AGO McManeus/Speros Cross Exhibit 5, please.

CHAIR MITCHELL: Document will be so marked.

MS. FORCE: Thank you.

(AGO McManeus/Speros Cross Exhibit 5 was marked for identification.)

Q. So please -- do you recall this -- I asked you a question about it a couple of years ago, Ms. McManeus.

Can you agree with me that this is a discovery request that was made in the last case and asks Duke if Duke had included any costs and depreciation for closure of ash impoundments? And the answer from Duke was that no final dismantlement costs were factored into the prior DEC depreciation study. It was assumed in the last dismantlement study that the salvage received for scrap would sufficiently offset the costs to dismantle. The previous dismantlement study occurred prior to the passage of CAMA and CCR legislation. The CAMA and CCR legislation have increased the estimated ash impoundment closure cost by significant amounts and are regarded -- recorded in accordance with the asset retirement allocation accounting documents; is that right?

A. That's what this data request response says.

Q. Okay. And I'd asked you some questions about that last time. I don't have any more questions for you at this point. The document speaks for itself. Thank you. I appreciate it.

A. I would note, Ms. Force, that, in this particular case, other witnesses are available to address any questions about depreciation rates and the dismantlement costs.

Q. Thank you. Appreciate that.

CHAIR MITCHELL: All right. Mr. Trathen?

MR. TRATHEN: Madam Chair, I don't have any questions.

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

(No response.)

CHAIR MITCHELL: Redirect for the panel?

MS. JAGANNATHAN: Chair Mitchell, I just have a couple of questions for Ms. McManeus.

CHAIR MITCHELL: All right. Please proceed.

REDIRECT EXAMINATION BY MS. JAGANNATHAN:

Q. Ms. McManeus, I just want to clarify with you that ARO coal ash spend is not included the Company's temporary rates that went into effect in August; is that right?

A. That's correct.

Q. Okay. And you discussed with Ms. Force the costs that the Company is seeking recovery for in this case, the January 2018 through January 2020 costs.

And to be clear, with respect to the coal ash compliance costs the Company is seeking to recover in this rate case, the Commission gave the Company specific instructions as to how to account for those costs; is that right?

A. Yes. In the Commission's previous order in Sub 1146, the Commission directed the Company to defer these costs -- so let me back up for a minute. In the previous case, the Commission rendered its order on the costs that were related to 2015, '16, and '17; but in its order, it addressed how the Company should handle costs subsequent to 2015, '16, '17. And it specifically directed the Company to defer those costs to a future rate case and to include a return on the deferred balance. And actually stated that, in the future case, unless imprudence was established, that it would permit a full return on the unamortized balance.

And so the Company has been following the Commission's instructions in deferring these costs and including the financing costs, the return in the deferred balance.

Q. Thank you.

MS. JAGANNATHAN: I don't have any more redirect.

COMMISSIONER DUFFLEY: I just have one question for Ms. McManeus.

EXAMINATION BY COMMISSIONER DUFFLEY:

Q. So when I asked a question of Mr. De May the other day, he referred me to you just to see if you have had any follow-up to his answer. And so I was basically asking him a hypothetical about if in this case, you know, hypothetically you had requested for the coal ash -- the ARO coal ash expenditures to be amortized over five years with a return on the unamortized piece. And then with respect to the EDIT, you-all agreed in your second stipulation to flow back unprotected federal EDIT over five years as well with a return. So -- and I heard Mr. De May's answer was that -- I asked if that would affect the revenue requirement or if he did a full offset in this case versus spanning those over five years. And he suggested that it would not have an impact on the revenue requirement. And I just ask that question of you as well.

A. (Jane L. McManeus) Well, as a result of that line of questioning, and some additional questions from Commissioner Clodfelter, we are now going to be pulling together the late-filed exhibit demonstrating or illustrating these concepts. And I think, at a high level, it's a fairly simple assumption to say you're offsetting one regulatory asset in a regulatory liability. But when you get down to doing the exact calculations, you've got to make some assumptions about return.

For example, sometimes a return is levelized; sometimes a return is not levelized. So to really do the calculations, you have to make a few assumptions. And as I understand it, the Public Staff is making a filing that asks for a little bit of clarity on some of these questions so that we can then prepare calculations that illustrate these questions and can do so based on the assumptions that the Commission would ask for.

Q. Okay. Thank you very much. I appreciate that.

COMMISSIONER DUFFLEY: I have nothing further.

CHAIR MITCHELL: All right. Commissioner Hughes?

COMMISSIONER HUGHES: No questions at this time.

CHAIR MITCHELL: Commissioner McKissick?

COMMISSIONER McKISSICK: One quick question, and that's for Ms. McManeus.

EXAMINATION BY COMMISSIONER McKISSICK:

Q. From what I'm reading, you're seeking not just a return, but also interest in addition to the return; is that correct? Just for purposes of clarity,

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in terms of me understanding the nature of the request at this time.

A. (Jane L. McManeus) Certainly. Commissioner, you're speaking of the coal ash recovery, correct?

Q. Yes. Yes.

A. Okay. So the way I think about it is, we use a number of terms when we're talking about this interest or return. Sometimes we call it the cost of money, sometimes we call it weighted average cost of capital, we say it's a debt and equity return, it's financing costs. So it gets kind of confusing. So the way I think about it is, when we have amounts that we spend, for example, on coal ash, that are not yet reflected in our rates -- so, for example, the 2018, '19 spend is not reflected in our rates.

So by definition, investors are advancing these funds. And investors are made up of both our bondholders, you know, debt investors, and common shareholders. So when we say we need to get a return, we're really saying that we need to collect the amount of money that we need to pay interest to the -- for the debt financing. And then, in addition, for the equity financing, we need a level of earnings that is attractive to equity investors.

So when we say we want a return, we're talking about total financing costs on these amounts that have been advanced, and it's made up of both debt and equity.

Q. That, I kind of understood, but the way I was -- and I think you clarified it. I mean, you're looking at the total cost that's involved there, in terms of the return to those who are stockholders, and whatever costs you might have spend separately and apart for monies that are borrowed that could have been related to it; is that correct?

A. Yes. So when I think of what the Company's requesting, I think of it in terms of being made whole, and being made whole in terms of cost. And in addition -- and in that category of cost, you certainly have financing costs as well as amounts that have been expended on remediation, you know, for coal ash -- for meeting coal ash compliance requirements.

So we have two types of costs, but both of them are definitely Company costs.

Q. Got it. Yeah. You know, I'm getting acquainted with all the terminology, and I basically understood the way you explained it. It's just that, when I was reading it on occasions, you know, it's clear to me when you're talking about a return, you're looking at what's going back to the stockholders. When I start thinking about other costs of capital, I'm thinking of that more in terms of, you know, borrowed funds that might have been used separately and apart from shareholder funds.

So, I mean, I guess I'm pretty clear now in terms of what you've indicated. It's just sometimes the terminology does not always seem consistent. Does that make sense?

A. Yes. And I would say that it sounds like you have a correct understanding that, if I spend a dollar, usually that dollar is financed by both debt and equity, and so we're going to have some interest expense, and I'm going to have some -- an earnings requirement for my common shareholders. So both are involved in financing my expenditures. It sounds like you've got that straight in your mind.

Q. All right. And, you know, I need to go back over some of these details here, and I'll probably have more questions at a future date. Will you be returning for other issues?

A. If I'm needed, my counsel has elected to have the right to recall me. So if things come up that I do need to address, I'll get to be last person to be called to address those.

Q. Well, hopefully, by the point that that might be needed, others would have provided additional clarity, so you'll be able to sit out. Thank you.

COMMISSIONER McKISSICK: Thank you, Madam Chair. I have no further questions.

MS. JAGANNATHAN: Thank you, Commissioner Clodfelter. And pursuant to the same stipulation, I would also ask that the following exhibits that were accepted into evidence in Docket Number E-7, Sub 1214, be identified as designated in the DEC rate case and moved into the record in this proceeding. And those are AGO McManeus/Speros Cross Exhibits 1 through 5.

COMMISSIONER CLODFELTER: All right. The parties have heard the motion. Are there any objections?

(No response.)

COMMISSIONER CLODFELTER: Hearing none, motion is granted.

(AGO McManeus/Speros Cross Examination Exhibits 1 through 5 from Docket Number E-7, Sub 1214 were admitted into evidence.)

COMMISSIONER CLODFELTER: All right. Ms. Jagannathan.

MS. JAGANNATHAN: Thank you. Ms. Smith is now available for cross examination.

COMMISSIONER CLODFELTER: All right. Ms. Force.

MS. FORCE: Thank you. And thank you, Ms. Jagannathan for the summary of the stipulation. That will save us some time.

CROSS EXAMINATION BY MS. FORCE:

Q. Good morning, Ms. Smith. My name is Margaret Force with the Attorney General's Office, and I have a few questions mostly about the coal ash costs. I do have one question first that's a little bit different. But if you would -- I'm going to be referring often to your second settlement testimony, the exhibit for that, so if you would have that ready, that would be helpful. That was filed on July 31, 2020.

A. (Witness peruses document.)

I have it.

Q. Are you there? Okay. If you look on Exhibit 1 -- I'm sorry, let me find the right place. I had looked through them, but I'd better get there too.

On Smith Exhibit 1, the amount that shows up for the amount of taxes -- North Carolina retail operations, the amount that would be reflected in the revenue requirement for the proposed increase relating to taxes, income taxes is $157.5 million; is that right? Do I have the right number for that?

A. You're on Exhibit 1?

Q. I am. The second settlement.

A. What page of Exhibit 1 are you on?

Q. I'm sorry. I found it. It's on Exhibit 1, and it's line 9. Page 1.

A. There is the total income taxes on column 1, total Company per books.

Q. That's right. And then if you go over to the far right column, that's column 6, is it 157 -- about $157.5 million?

A. And I am seeing 163.976, I must not be on the same filing, so just a minute.

(Witness peruses document.)

Q. Hopefully --

A. Did you say 151.769?

Q. Well, I have a little different number. 157.494 is what I see in column 6. That's line 9 on your page 1, second settlement. Are we at the same place? I didn't mean to make it complicated. Sorry. It sounds like the number you gave was very close.

A. I think your -- subject to check, I will -- but whichever settlement you're looking at, subject to check, I'll say that is correct; how's that?

Q. And I believe I'm using the settlement that was filed on July 31, 2020; is that what you're referring to?

MS. JAGANNATHAN: Ms. Force, I have the same number as you, so I can see where you are. So I can confirm that that's the correct number.

MS. FORCE: I didn't mean to take up very much time with that. Most of my questions are going to be relating to the numbers that relate to the coal ash.

Q. So let's flip back a little bit and we'll go on to that, and hopefully the numbers line up then when we do the next numbers.

For -- referring to your Exhibit 1, as you go back through the exhibit, you have a number of adjustments. One of them being for coal ash, and that's item 11, correct, for the deferred environmental costs?

A. That is correct.

Q. Okay. And the exhibit that details the adjustment shows up on pages NC1100 through NC1110; is that right?

A. That is correct.

Q. Okay. So we're going to look at those now. According to my notes, on page 1100 in the second settlement, you have a breakdown that shows ARO and non-ARO coal ash-related costs; isn't that right?

A. That's correct.

Q. So to clarify, when you use the labels ARO and non-ARO, those are categories that distinguish the costs that are related to the closure of ash ponds and disposal of CCR as opposed to costs that are incurred for ongoing operations; is that right? That are ARO-related -- excuse me, that are coal ash-related?

A. Yes. Would you mind asking your question again.

Q. Sure. Just to clarify the distinction that's drawn between ARO and non-ARO, since these are both related to coal ash, the ARO costs you've identified are for closure of ash ponds and disposal of CCR, and that distinguishes from costs that are incurred for ongoing operations like dry ash handling and water treatment?

A. Yes, ma'am.

Q. Okay. Good. So if we look at 1100 -- and I don't know -- there's not a page number that's as easy to find, but it's called 1100. And in my PDF file, that's page 60, if you're looking at the electronic copy.

A. Yes, I have that.
Q. Flip back to that. That's where it appears that you've given a narrative about what these adjustments are for, correct?
A. Yes, that is correct.
Q. And then looking to the next page, 1101, this breaks down the amount for the ARO portion and the non-ARO portion. And if you look at it with me, it's $480.114 million for the ARO part, and then $39.999 million for the non-ARO; is that right?
A. Yes. Did you say 440.115 for the ARO portion?
Q. Yes.
A. And 39.999 for the non-ARO. Yes, ma'am that's correct.
Q. Good. We're in the same numbers this time. And then 1102, it breaks down -- we're going to focus on the ARO part. If you look on -- that's page 63 of the PDF document. And am I right, then, that when we take that ARO part, the total is -- shows $404.634 million is the amount that was spent from September 2017 through February 2020, and that's on line 40; do you see that?
A. Yes, I do.

Q. Okay. So that's the total amount that was spent without including any carrying costs.

The next numbers I'm going to read out to you are for cost of removal items that were still being recovered before the new rates took effect; am I right about that?

A. On the cost of removal, that is where -- that reflects -- the cost of removal credits reflects what we were collecting in -- through the depreciation. And in the last rate case, we asked to put those amounts that were already collected against the deferral to lower the amount we needed to collect from customers. We already collected those amounts from customers.

Q. So in the first few months before the new rates took effect, those amounts show up in total in your tally on page 1102 as $1.324 million to offset the amounts recovered for the cost of removal for active plants, and then $4.176 million is the amount that was collected from prior rates for cost of removal for retired plants; is that right?

A. You said $1.3 million and 4.2 million?

Q. About, right. 1.324 and then 4.176.

A. It's correct.

Q. Okay. So the net of those amounts, then, reflects what -- an amount that's not shown there, but just about $400 million, correct, $399 million?

A. That is correct.

Q. So then there's another column there that shows the rate of return that was booked during the referral period of $40.980 million, correct?

A. Yes, ma'am; that is correct.

Q. Okay. Now -- so during those periods, these are the amounts that we're looking at as the total ARO-related coal ash costs in this case.

Is there any further adjustment for months after the period of this settlement that would be reflected ultimately through the time that new rates apply?

A. No. The coal ash is not included in our interim rates that we put into effect September 1st, so this is all that we're asking for in this case.

Q. But interim rates did start to take effect at some point for Duke Energy Progress, right, temporarily?

A. Yes, it did. But in the creation of the interim rates, they did not -- we are not collecting anything related to coal ash.

Q. Okay. And when did those take effect?

What's the exact date?

A. September 1st.

Q. Okay. That's what I thought. All right. So -- but as far as these costs go, the deferral amount that was paid, the $40.98 million, that's based on the overall rate of return for Duke Energy Progress from the last rate case, or current rates; is that right?

A. Yes, ma'am. Or weighted average cost of capital.

Q. Okay. And that's based on the long-term debt and the return on equity, but it is -- would you agree with me that the longest time that Duke carried the cost was roughly 36 months, about three years back to September 2017?

A. Yes, back to September 2017.

Q. And many of those costs were incurred more recently than that?

A. Yes, that's correct.

Q. Over the period. Okay. So now let's take a look at the amount that Duke proposes to include in cost of service. And that's taking the total of -- am I right, 440.115 is what those -- is the total amount that is going to be recovered, and that's -- the proposal is to amortize that over five years, right?

A. That is correct.

Q. So on line 8 on, let's see, 1101, turning back to that page, am I right that it's $88.023 million per year that would be recovered in annual revenue requirement, not including the rate of return part going forward?

A. That is correct.

Q. So that leaves a balance of unamortized costs of $352.092 million?

A. Yes, ma'am.

Q. That amount, then, some of that is going to be booked as accumulated deferred income taxes leaving a balance that goes into rate base of $270.5 million; is that right?

A. Yes, that's correct.

Q. Okay. So what if we were to take -- what's the amount that that works out to be that's going to be included in the revenue requirement annually for the rate base rate of return on the unamortized balance, please, approximately?

A. I'm sorry, approximately $23 million.

Q. Okay. So if we take 23 and 88, it's over $100 million a year, then, we're talking about in cost of service or the annual revenue requirement in this case?

A. Yes. $111 million, approximately.

Q. Right. Okay. And Duke is still amortizing the coal ash costs from the last rate case too, right?

A. Yes, ma'am.

Q. And that was about $60 million per year; is that right?

A. It was actually $53 million.

Q. And is that including the -- okay. That includes the rate of return and rate base, comparable number?

A. Yes, it does.

Q. So when we're talking about the two together, then, are we talking about over 100 and -- over $160 million per year?

A. Yes, ma'am, we are.

Q. And Duke Progress has 1.4 million North Carolina retail customers, right?

A. That sounds about right.

Q. I took that from the application at page 3. I know the number is not precise.

So that amounts to somewhere between 118 and 120 million -- excuse me, $118 and $120 per year per customer if you were to just simply spread that over customers; is that right?

A. Yeah, but that's not normally the way we calculate the cost per customer.

Q. Sure, sure. Okay. So the non-ARO costs is the other category of coal ash that's included in the total numbers in some of the testimony that you've provided. And would you agree with me that the -- those costs had been made at coal plants that are active and relate to conversion -- dry ash conversion and alternate water measures?

A. Yes, from what I understand.

Q. As I recall in the last rate case, those were treated as more like capital costs that were separate; I've heard that referenced in this one; so it's a different category of cost?

A. It is a different category of cost. And witness Doss could explain the different categories and why some goes in one category and some goes in ARO and non-ARO categories.

Q. Okay. Now, I'd like to go over a document and get it into evidence, and I won't spend much time with this, but I'd, first of all, refer you to what was introduced in the last rate case, and so it's been brought in in this case by stipulation as AGO

McManeus/Speros Cross Exhibit 1. It will be easier for you to find, perhaps. It's the petition that Duke filed for an accounting order in the last rate case, and it applied to both DEC and DEP.

MS. JAGANNATHAN: Ms. Force, can you give Ms. Smith the reference to the DEP potential cross exhibit number, if you have it?

MS. FORCE: I had it at one time and got rid of it. Sure. I think it's 43, but I'm afraid I may be referring to the prior docket. I mean --

MS. JAGANNATHAN: Ms. Force, it might be Exhibit 40. Is it Duke's request for an accounting order?

MS. FORCE: That's right.

Q. And really, it's -- I'm going to refer you to a footnote, so we can do this subject to check. If you look in that petition, there is a reference in footnote 2 on page 5 to a 2003 order that was issued in E-2, Sub 826. It's been referred to in this case sometimes as the ARO order.

A. Yes, I have that page in front of me.

Q. Okay. All right. Good. And actually, it's -- I wanted to introduce the order in the CP&L case that would be relevant to this docket. So if you would turn for that to AGO Potential Exhibit 34, I believe I have the right one. And you'll see that that is Docket Number E-2, Sub 826 in the matter of Carolina Power & Light, and it's called "Order granting motion for reconsideration and allowing deferral of costs."

A. Just a minute. I had to change books.

Q. Sure.

A. (Witness peruses document.)

I have it in front of me now.

Q. Okay. Thank you. Good.

MS. FORCE: I'd ask that this be marked as AGO Smith/Speros Cross -- I'm sorry, I had the wrong -- this isn't really a panel at this point. Should we just say AGO Smith Cross Exhibit 1?

COMMISSIONER CLODFELTER: Let's say -- let's call it Smith Direct AGO Cross Examination Exhibit -- just to be on the safe side, let's call it 6. Even though she is testifying in place of Ms. McManeus and not as part of a panel, this is a bit -- a bit of a unicorn here. We've got -- I think, so there's no confusion about the numbering -- and I see Mr. Mehta appearing on my screen, so he's going to guide me through this. The safest practice is to call it -- yes, Mr. Mehta?

MR. MEHTA: Commissioner Clodfelter, the exhibit police need to weigh in here. And I will apologize in advance whenever I'm marking one of these, because I'm sure I will mess it up entirely. But Ms. Smith is here on both direct and rebuttal. Therefore --

COMMISSIONER CLODFELTER: Therefore, we don't need the direct rebuttal distinction?

MR. MEHTA: Correct.

COMMISSIONER CLODFELTER: So we will call this Smith AGO Cross Examination Exhibit -- I still think we ought to use 6 just to be on the safe side.

MR. MEHTA: Correct.

COMMISSIONER CLODFELTER: It will be so designated.

MS. FORCE: So I have it right too, it's Smith AGO Cross Exhibit 6?

COMMISSIONER CLODFELTER: You got it.

MS. FORCE: Okay. Good.

(Smith AGO Cross Exhibit 6 was marked for identification.)

Q. Would you agree with me, Ms. Smith, that this is the order that was referred to in Duke's petition for an accounting order regarding coal ash costs?

A. Yes, ma'am, I agree.

Q. That's all. Thank you. I don't have any further questions. I appreciate it.

(Reporter interruption due to Commissioner Clodfelter's audio being muted.)

COMMISSIONER CLODFELTER: I don't see notes of any other party asking to reserve cross examination, but I'll ask again. Public Staff or any other intervenor?

MS. HOLT: No questions.

COMMISSIONER CLODFELTER: Okay. Have cross examination for the witness, if not, redirect, Ms. Jagannathan?

MS. JAGANNATHAN: Thank you.

REDIRECT EXAMINATION BY MS. JAGANNATHAN:

Q. You were talking with Ms. Force about the $53 million relating to the continued amortization of the regulatory asset approved in Duke Energy Progress' last rate case; do you recall that conversation?

A. Yes, I do.

Q. And that $53 million is not part of the increase in revenue requirement the Company is seeking in this rate case; isn't that right?

A. Yes, that is correct. It is already part of current rate, so is it not incremental.

Q. Okay. Thank you for that clarification. I have nothing further.

COMMISSIONER CLODFELTER: Thank you. Let's see if we have questions from Commissioners.

Commissioner Brown-Bland?

COMMISSIONER BROWN-BLAND: No questions.

COMMISSIONER CLODFELTER: Commissioner Gray?

COMMISSIONER GRAY: No questions.

COMMISSIONER CLODFELTER: Commissioner Mitchell? Chair Mitchell?

CHAIR MITCHELL: No questions.

COMMISSIONER CLODFELTER: Commissioner Duffley?

COMMISSIONER DUFFLEY: I just have one clarifying question, and it might be a more appropriate question for witness Doss.

EXAMINATION BY COMMISSIONER DUFFLEY:

Q. I thought I heard you state that non-ARO costs, like with water testing would be a non-ARO compliance cost; is that correct?

A. That would be a better question for witness Doss.

Q. Okay. Thank you. No further questions.

COMMISSIONER CLODFELTER: All right, Commissioner Hughes?

COMMISSIONER HUGHES: No questions.

COMMISSIONER CLODFELTER: Commissioner McKissick?

COMMISSIONER McKISSICK: No questions.

COMMISSIONER CLODFELTER: All right. I have no questions. So, Ms. Jagannathan, I think that that's it, and we're ready for motions if there are any.

MS. JAGANNATHAN: The Company doesn't have any motion with respect to Ms. Smith at this time. I believe we reserved the right to recall her at the end of the case if necessary. Thanks.

COMMISSIONER CLODFELTER: Ms. Force?

MS. FORCE: And I'd move to admit the Smith AGO Cross Exhibit 6 into the record, please.

COMMISSIONER CLODFELTER: Hearing no objection, it will be so ordered.

(Smith AGO Cross Exhibit 6 was admitted

into evidence.)

MS. FORCE: And to clarify, the other exhibits are already in the record by stipulation and --

COMMISSIONER CLODFELTER: That's correct. And Ms. Jagannathan moved those in at the beginning of the witness' testimony.

MS. FORCE: Good. Thank you.

COMMISSIONER CLODFELTER: Ms. Smith, you are subject to recall, so I'm not sure we can finally dismiss you, but your counsel will advise you accordingly. Thank you.

THE WITNESS: Thank you.

COMMISSIONER CLODFELTER: Mr. Robinson, let's see where we are. Back to you.

MR. ROBINSON: Thank you, Commissioner Clodfelter. As you indicated, Ms. Smith was the last of our direct case, so that will end our direct case and we'll move on to intervenor cases.

Commissioner Clodfelter, the motion I will make is not quite a renewal but more of a revision. At this time, while we don't intend to put Mr. Riley up as an individual witness, we will not seek to formally excuse him at this time and rather reserve the right to call him in the event we need him to appear to clarify any issues that may arise as the proceeding continues.

So accordingly, at this time, I revise my motion to only seek to move Mr. Riley's rebuttal testimony and one exhibit into the record as if given orally in the stand. Again, I'm doing this in anticipation of us not calling him, that's why I'm doing it now. Thank you.

COMMISSIONER CLODFELTER: His exhibit will be marked as identified as prefiled rebuttal testimony, correct?

MR. ROBINSON: Yes, sir.

COMMISSIONER CLODFELTER: All right. You've heard the motion, is there any objection from any party?

MS. DOWNEY: Commissioner Clodfelter, just a question, no objection. But I understand Mr. Riley, if I understand it correctly, is subject to a stipulation. At what point -- is that correct?

COMMISSIONER CLODFELTER: I believe that's correct. Mr. Robinson, were you intending to move the stipulation in and the rebuttal case or what do you want to do about that?

MR. ROBINSON: Commissioner Clodfelter, I may be misremembering. I thought -- I thought I had moved that in previously. So actually I recall now, I think, Ms. Downey, you had indicated that you wanted that additional time to move in that transcript citation and exhibits to acknowledge and confirm that that -- all of those exhibits or any exhibits that referred were included. So do I need to renew that? I'm happy to do that as well.

COMMISSIONER CLODFELTER: I think for good order's sake, because that was at the very beginning, and it's only been two days but we've come a very long way in these two days. So just for good order's sake let's do that again just to be sure we haven't missed anything at all. Okay?

MR. ROBINSON: Certainly. So subject to and per that stipulation that Ms. Downey just referenced pertaining to the coal ash and accounting witnesses, I would move at this time also that the stipulated live testimony of DE Carolinas -- or Sean Riley, who was the DE Carolinas witness in the DEC case, that stipulated live testimony be moved into the record as if given orally from the stand in the DEP case. And I have the transcript citation here whenever you're ready, Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Please proceed.

MR. ROBINSON: All right. Transcript Volume 23, page 150, line 1 through page 183, line 20. As well as transcript Volume 24, page 12, line 2 through page 36, line 24.

COMMISSIONER CLODFELTER: And, Mr. Robinson, we've already accepted his prefiled testimony and the exhibit therewith; were there any exhibits with the stipulated testimony that need to be moved in?

MR. ROBINSON: Not to my knowledge, Commissioner Clodfelter. Ms. Downey, if you have any that I missed, please feel free to include. But not to my knowledge, Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Ms. Downey?

MS. DOWNEY: I will double-check, but I'm not aware of any.

COMMISSIONER CLODFELTER: All right. We have the motion from Mr. Robinson. Is there any objection?

(No response.)

COMMISSIONER CLODFELTER: Hearing none, motion is granted.

(Riley Rebuttal Exhibit 1 was admitted into evidence.)

(Whereupon, the prefiled rebuttal testimony of Sean P. Riley, as well as testimony from Docket E-7, Sub 1214, Volume 23, page 150, line 1 through page 183, line 20; and Volume 24, page 12, line 2 through page 36, line 24 were copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of:	)	
	)	**REBUTTAL TESTIMONY OF**
Application of Duke Energy Progress, LLC	)	**SEAN P. RILEY**
For An Adjustment of Rates and Charges	)	**FOR DUKE ENERGY**
Applicable to Electric Service in North	)	**PROGRESS, LLC**
Carolina	)	

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Sean P. Riley. My business address is PricewaterhouseCoopers LLP, 601 South Figueroa Street, Los Angeles, CA 90017.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS REBUTTAL TESTIMONY?

A. I am submitting this rebuttal testimony on behalf of Duke Energy Progress, LLC ("DEP" or the "Company").

Q. PLEASE DESCRIBE YOUR OCCUPATION AND WORK EXPERIENCE.

A. I graduated from the University of Vermont in 1990 and was hired by Coopers & Lybrand (predecessor company to PricewaterhouseCoopers LLP ("PwC")) in 1992 as an auditor focused on the financial statement audits of regulated utilities. PwC is the largest professional services network in the world, providing audit, tax and advisory services to the largest and most complex companies globally. I was admitted to the partnership of PwC in 2004. I am a certified public accountant ("CPA") currently licensed in the States of California, Maine and Massachusetts.

I am a member of PwC's National Power, Utility and Renewable Energy Practice. Our nationally recognized practice is viewed as a leader in the Utilities sector, and comprises over 1,300 professionals, including professionals notably experienced in serving rate regulated entities. We serve all of the largest and most complex regulated utilities in the United States.

I currently have two roles within our Utility practice. First, I am an Assurance Partner leading significant financial statements and internal controls over financial reporting audit engagements in the Power and Utility sector. In addition, I lead PwC's Complex Accounting and Regulatory Solutions ("CARS") practice. In this role, I oversee a team of highly experienced utility sector specialists that advise clients on complex technical accounting and regulatory / ratemaking matters. In addition, our CARS team is responsible for the development of thought leadership related to the Power and Utilities Sector.

I previously completed a three-year tour as the Power and Utility technical accounting leader in the Accounting Services Group within PwC's National Office. I am a frequent speaker at PwC utility industry events, as well as for organizations such as the Edison Electric Institute and American Gas Association.

Q. HAVE YOU DEALT WITH THE UNIQUE ACCOUNTING AND FINANCIAL REPORTING ISSUES ENCOUNTERED BY REGULATED ENTERPRISES?

A. Yes. Throughout my career, I have focused on utility accounting and regulatory / ratemaking issues primarily as a result of auditing regulated enterprises. The unique generally accepted accounting principles ("GAAP") applicable to regulated entities embodied in Accounting Standard Codification ("ASC") 980 *Regulated Operations ("ASC 980")* (previously known as Statement of Financial Accounting Standard ("SFAS") 71, *Accounting for the Effects of Certain Types of Regulation ("SFAS 71")*) and related standards all need to be understood so that auditors can determine if a company's accounting has been applied appropriately. During my career, I have consulted with utilities, and internally with other PwC engagement teams, as to how these standards should be applied.

Q. HAVE YOU PROVIDED TRAINING ON THE APPLICATION OF GAAP TO REGULATED ENTERPRISES?

A. Yes. I have developed and presented utility accounting seminars focusing on the unique aspects of the regulatory process and the resulting accounting consequences of the application of GAAP. I have presented at seminars as well as delivered training on an in-house basis. I have also presented at various Edison Electric Institute and American Gas Association ratemaking and accounting seminars.

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR TESTIMONY.

A. My testimony will address the following items: (1) Describe the applicable GAAP for rate regulated entities such as Duke Energy Progress, LLC under which the accounting follows the ratemaking; (2) Describe the accounting for Asset Retirement Obligations under ASC 410, *Asset Retirement and Environmental Obligations* ("ASC 410*") (*formally known as SFAS 143, *Accounting for Asset Retirement Obligations* ("SFAS 143") and FASB Interpretation 47, *Accounting for Conditional Asset Retirement Obligations* ("FIN 47")); (3) Describe how regulators permit recovery of expenditures / costs and the GAAP accounting for such actions. Costs are often recovered in the ratemaking process either as or after they have been incurred but are also recovered in certain circumstances in advance of the actual expenditures; and (4) Summarize DEP's accounting for coal ash remediation efforts and the related ratemaking history.

Q. DOES YOUR TESTIMONY INCLUDE ANY EXHIBITS?

A. Yes. Riley Rebuttal Exhibit 1 includes my educational and professional background.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. My testimony concludes that DEP's accounting for coal ash costs, the history of which has been described to us by the Company's management, is appropriate under GAAP, which are required to be followed by registrant companies of the Securities and Exchange Commission ("SEC") such as DEP. Further, DEP's depreciation expense is also consistent with GAAP because such accounting follows the ratemaking treatment for such costs. [1]

II. GENERALLY ACCEPTED ACCOUNTING PRINCIPLES APPLICABLE TO RATE REGULATED ENTITIES

Q. BEFORE DISCUSSING THE SPECIFIC ISSUE OF DEP'S ASH POND COST RECOVERY, CAN YOU PROVIDE A BACKGROUND ON THE APPLICATION OF GAAP TO RATE REGULATED ENTITIES SUCH AS DEP?

A. Yes. GAAP provides the framework for measuring and reporting assets, liabilities, revenues and expenses in financial statements. Such principles present a "common yardstick" for investors and others who are interested in the

[1] This testimony was prepared in connection with the filing of Duke Energy Progress with the North Carolina Utilities Commission and for the use and benefit of Duke Energy Progress. PwC disclaims any contractual or other responsibility to others based on their access to or use of testimony and the information contained herein.

financial condition and results of operations so that investors can evaluate the entity, for among other things, potential investment. The Financial Accounting Standards Board ("FASB") and predecessors promulgate accounting principles for various transactions. Periodic reporting of results under GAAP for publicly traded entities occurs through Annual Reports to investors and other stakeholders (for example, state and federal regulators, including the SEC, the agency responsible for protecting investors). While GAAP presents a common yardstick for accounting and reporting, there are certain industries where GAAP takes into account the unique nature of such industries so that the appropriate financial results are presented in a way that reflect the differing economic consequences of that industry.

Q. DOES RATE REGULATION CREATE UNIQUE ECONOMIC CONSEQUENCES THAT NEED TO BE CONSIDERED WHEN PRESENTING FINANCIAL RESULTS UNDER GAAP?

A. Yes. Under traditional rate regulation for investor-owned utilities, the prices charged for services provided by utilities (electric, gas and water entities) are regulated (subject to review and approval) by a state's regulatory commission and / or the Federal Energy Regulatory Commission ("FERC"), as applicable. This is because such entities provide a necessary service and operate as monopolies. Without such regulation, the monopoly utility could charge whatever it could, and would therefore potentially earn "super-monopoly" profits. Instead, the regulatory compact permits the utility to operate in a specific service territory and, in return, the regulatory commission regulates various aspects of the utility, including pricing.

The prices charged by a rate-regulated utility are based on the utility's cost of providing service, including both capital and operating costs. Capital costs include a return on investment to utility investors measured as the allowed rate base times an allowed rate of return. Operating costs include the costs of providing service to customers and include necessary operating and maintenance expenses, depreciation and taxes, among others. A rate case is the vehicle for presenting costs to a regulator for recovery and determining the revenue requirement of a utility.

Q. HOW DOES RATE REGULATION IMPACT GAAP?

A. In the ratemaking process, the regulator can decide to permit recovery of a cost in a period that is different from when GAAP would require such cost to be reported. For enterprises in general, there is no direct link between expenses and revenues. For such enterprises, revenues / prices are based on what the market will bear. Because rate-regulated utilities are not subject to competition, the regulator acts as a substitute for competition and requires rate cases for the utility to present its costs for the development of its revenue requirement (prices). Under this unique rate-regulation mechanism, there is a matching of revenues and costs that should be reflected in the utility's financial statements. This is accomplished via ASC 980, *Regulated Operations* (ASC 980), which includes the concepts initially included in SFAS No. 71.

Q. WHAT IS ASC 980 AND ITS PREDECESSOR STATEMENT SFAS 71?

A. SFAS 71 was issued by the FASB in 1982. This Statement was the primary accounting principle providing accounting guidance for rate regulated entities and addressed the unique accounting for entities where a clear linkage exists between rates or tariffs charged to customers and a rate regulated company's cost. A rate regulated enterprise's costs include both necessary operating expenses and an allowed return (representing the cost of capital, both debt and equity).

Under SFAS 71, utilities are required to defer, as regulatory assets, incurred costs that non-regulated entities would charge to expense if, as a result of the regulatory process, it is probable that such costs will be recovered in future charges to ratepayers. Additionally, rate regulated entities are required to record regulatory liabilities when it becomes probable that a regulator will require the refund of revenues previously charged to and collected from ratepayers, or when amounts are collected in advance of a cost being incurred. The FASB codified the concepts of SFAS 71 within ASC 980, *Regulated Operations* in September of 2009.

Q. WHAT ARE THE REQUIREMENTS FOR APPLYING ASC 980?

A. ASC 980-10-15-2 provides the specific scope requirements of ASC 980. Entities with regulated operations that meet all of the following criteria are required to apply ASC 980 to the general purpose-external financial statements of its regulated operations:

> *a. The entity's rates for regulated services or products provided to its ratepayers are established by, or are*

> *subject to, approval by an independent, third-party regulator or by its own governing board empowered by statute or contract to establish rates that bind customers.*
>
> *b. The regulated rates are designed to recover the specific entity's costs of providing the regulated services or products ...*
>
> *c. In view of the demand for the regulated services or products and the level of competition, direct and indirect, it is reasonable to assume that rates set at levels that will recover the entity's costs can be charged to and collected from customers. This criterion requires consideration of anticipated changes in levels of demand or competition during the recovery period for any capitalized costs ...*

Q. GENERALLY, WHICH TYPES OF ENTITIES FOLLOW THE ACCOUNTING UNDER ASC 980?

A. Historically, rate regulated electric, gas and water utilities follow the accounting requirements of ASC 980. Unlike competitive entities, where the rates / prices charged for products or services are based on competition, rate regulated entities typically set the rates they charge their customers based on their costs, as determined in a rate case in which test year operating and capital costs are presented to a regulator, with a revenue requirement based on costs ultimately ordered. Utilities typically have exclusive right to and are required to provide service in their authorized jurisdiction in exchange for the Commission's oversight of a number of operational and financial factors, such as determining the rates that can be charged to customers. The economic effects of regulation were considered unique by the FASB when they considered the accounting that eventually resulted in ASC 980.

Said another way, because rate regulated utilities are permitted to charge rates (revenue) based on costs, their financial statements should recognize the direct linkage between costs and revenues. Further, if a regulator permits recovery (revenue) of a cost subsequent to an accounting period when the actual cost was incurred, that cost should be deferred on the balance sheet (rather than expensed in the income statement) and amortized to the income statement in the period in which the revenues to recover that cost are being reflected. This accounting matches the costs (expenses) and revenues (based on those costs).

The important point here is that, for utilities, accounting follows ratemaking, not the other way around.

Q. CAN YOU PROVIDE A SIMPLE EXAMPLE OF HOW ASC 980 IS APPLIED?

A. Yes. Assume a hurricane occurs in 2019 resulting in considerable damage to two entities. One entity is a rate regulated utility and the other is an unregulated maker of widgets. Both entities spend $20 million performing a variety of storm restoration and maintenance activities to repair the damage caused by the hurricane. Under GAAP, both entities would record $20 million of maintenance expense in 2019 as both companies incurred $20 million of maintenance costs in the period.

The widget maker presumably would not be able to pass along the $20 million maintenance expense in the price of widgets because widget prices are set by the competitive widget market where there is no direct correlation between current costs and future revenues. Thus, that company would likely report lower than expected net income in 2019 due to the hurricane. The regulated utility company would likely seek recovery of this cost from its regulator. Precedent would play an important role in determining whether rate actions of the regulator would permit future rate recovery of the storm costs. If the utility concluded that recovery of the $20 million was probable (i.e., greater than a 75% likelihood of recovery), it would reverse the $20 million of maintenance expense (remove from the 2019 income statement) and record a regulatory asset (add to the 2019 balance sheet). The regulatory asset would then be charged to expense (amortized) in the period that the regulator permitted recovery of the regulatory asset through rates. So, if the regulator permitted recovery of the $20 million storm restoration and maintenance at the rate of $5 million per year for four years beginning in 2020, the utility would amortize $5 million of the regulatory asset each year as amortization expense to match the $5 million of additional revenues it is able to bill customers to recover that cost.

Q. IN YOUR EXAMPLE, THE UTILITY DOES NOT REPORT AN EXPENSE IN ITS 2019 INCOME STATEMENT LIKE THE WIDGET COMPANY BUT DEFERS THAT COST ON ITS BALANCE SHEET (AS A REGULATORY ASSET), AND SUBSEQUENTLY AMORTIZES THAT COST TO THE INCOME STATEMENT IN THE PERIODS IT IS BEING RECOVERED IN REGULATED RATES. IS THAT BECAUSE OF COST-BASED RATE REGULATION?

A. Yes. SFAS 71 as originally issued noted:

> *"This Statement may require that a cost be accounted for in a different manner from that required by another authoritative pronouncement. In that case, this Statement is to be followed because it reflects the economic effects of the rate-making process—effects not considered in other authoritative pronouncements. All other provisions of that other authoritative pronouncement apply to the regulated enterprise."*

The ratemaking process provides a linkage between costs and revenues, creating an economic effect which is reflected in GAAP financial statements for rate regulated entities. ASC 980 has been in effect for many years and the concept of regulatory assets and regulatory liabilities is not a new one. If the conditions of ASC 980 are met, regulated entities will recognize a regulatory asset or liability whenever expenses or revenues are recognized in one period for regulated ratemaking but would have been recognized in another period under GAAP for an unregulated entity.

The important point here is that the GAAP accounting for rate-regulated utilities follows the ratemaking process to reflect the unique, economic consequences of rate regulation.

Q. ARE THERE OTHER EXAMPLES YOU CAN CITE ON HOW ASC 980 IS APPLIED?

A. Yes. Utilities with automatic fuel adjustment clauses defer the difference between the fuel expenditures incurred in the period and the fuel expense being collected through current rates as a regulatory asset or liability so that the fuel expense shown in the income statement matches the fuel expense collected through current rates. Fuel expense in excess of the amount collected through current rates is deferred until the period in which such expense is charged to customers. Again, such difference between the GAAP expense and ratemaking recovery is deferred by regulated entities as a regulatory asset or liability. There are many other similar examples that could be cited.

Q. WHEN UTILITY INVESTORS SUPPLY THE FUNDING FOR EXPENDITURES PRIOR TO RECOVERY FROM CUSTOMERS, IS A RETURN GENERALLY PERMITTED ON SUCH A REGULATORY ASSET UNTIL RECOVERY HAS OCCURRED?

A. Yes. In utility accounting and ratemaking there is a concept of “recovery of” and “return on” investment. Simply stated, recovery of the investment means the investor receives full cost recovery of each dollar invested. This is best illustrated by referring to the investment in property, plant and equipment. An investment in a generating facility, for example, requires capital investment on the front end to acquire or construct the facility. The investor recovers their investment as the plant is depreciated and the customers pay the revenue requirement (which includes recovery of depreciation expense). However, as the investor has supplied the funds for investment in the plant in advance of recovering such investment, they are also entitled to a return on their investment related to the time value of money, opportunity cost and risk associated with that investment. Therefore, the undepreciated cost (i.e., remaining net book value) of the plant is included within rate base and earns an allowed return. In this manner, over the asset’s life, the investor receives their money back and earns a return on their investment until fully recovered.

The same concept applies to other investor funding where recovery occurs over time. In my hurricane example above, this would result in the regulatory commission permitting a return on the unamortized regulatory asset until such balance has been recovered to reflect the upfront cost of financing provided by the utility investor.

Q. WHAT IF INVESTORS DO NOT RECEIVE BOTH RECOVERY OF AND RETURN ON THEIR INVESTMENTS?

A. If investors do not receive both recovery of and return on investment, it increases investment risk and, all other things being equal, may increase a company's cost of capital. As capital-intensive industries, such as utilities, require significant capital investment, not permitting an adequate return on investment may impact a company's ability to attract capital. As most utility investment funding is both recovered and receives a return, capital investment that does not recover both is at a competitive disadvantage.

III. <u>ASC 410 ASSET RETIREMENT AND ENVIRONMENTAL OBLIGATIONS</u>

Q. WHAT ARE THE REQUIREMENTS OF ASC 410 UNDER GAAP?

A. ASC 410 establishes the GAAP standard to account for legal retirement obligations. The Standard became effective in 2003 and requires an entity to determine if it has a present legal obligation to remove, dispose, or remediate an asset. If a legal obligation presently exists, the fair value of the legal obligation is to be recorded as an Asset Retirement Obligation (ARO) with a corresponding Asset Retirement Cost (ARC) recorded as well. The initial accounting journal entry is as follows:

Dr. ARC	XXX
Cr. ARO	XXX

The entity would then depreciate the ARC asset over the underlying asset's economic life and accrete, or increase, the ARO liability through the estimated retirement date, such that when the retirement cost is paid, the ARC asset would have been fully depreciated and the ARO liability would have increased to the amount of the full obligation. Both ARC depreciation expense and ARO accretion expense are recorded on the income statement over time to recognize the estimated costs of settling the legal obligation in the periods that the related asset is being used. As a result, when the underlying asset reaches the end of its useful life, the Asset Retirement Obligation would represent (i.e., be equal to) the cost to settle the obligation at that time.

Q. HOW DOES ASC 410 DEFINE LEGAL AROS?

A. ASC 410 is the codification of the concepts contained within SFAS 143, *Accounting for Asset Retirement Obligations* ("SFAS 143"). SFAS 143 became effective in 2003, with a scope that included the costs of "legal obligations associated with the retirement of a tangible long-lived asset." Specifically, "The statement only applies to costs related to the retirement of a tangible long-lived asset resulting from "acquisition, construction, or development and / or normal operation of a long-lived asset." The definition was expanded by Financial Interpretation (FIN) 47, *Accounting for Conditional Asset Retirement Obligations - An Interpretation of FASB Statement No. 143* to include "conditional" obligations to remove or dispose of assets.

Common AROs in the electric utility industry include decommissioning of nuclear plants, Federal and state requirements to safely close ash ponds, and costs to remove asbestos from facilities. The retirement activities for the majority of the utility industry's assets have not been classified as AROs (and do not meet the accounting requirements of ASC 410) because they are not legal obligations (i.e., there is no legal obligation to retire an asset). However, this does not mean that removal costs on such assets will not be incurred or not recognized in GAAP. GAAP requires that non-legal retirement costs be recognized when incurred, typically at the end of an asset's life, prior to consideration of any ratemaking impacts and the effect of ASC 980.

Q. PLEASE DESCRIBE IN MORE DETAIL HOW THE INITIAL ARO LIABILITY AND ASSET RETIREMENT COST ASSET ARE DETERMINED UNDER ASC 410?

A. The process to determine the ARO liability begins with estimating the future cost associated with the legal obligation. The estimated future cost is then discounted using a "credit-adjusted risk-free rate." The discounted future obligation is recorded on the balance sheet (credit) with an equal increase in the fixed asset balance (debit) for the ARC asset at the time the legal obligation arises (which could be as of, prior or subsequent to the point in time that the property is placed in service).

This ARC asset amount is depreciated on a straight-line basis through depreciation expense. The discounted ARO liability is increased each year through an accretion expense charge such that the ARO liability amount will increase to the ultimate cost to remove the asset by the estimated removal date (which may be at or several years after the date the asset is retired).

Q. IS AN ARC RECORDED EVEN IF THE UNDERLYING ASSET HAS REACHED THE END OF ITS USEFUL LIFE WHEN THE LEGAL OBLIGATION FIRST ARISES?

A. No. In a situation where the legal obligation arises subsequent to the end of the underlying asset's useful life, no ARC is recorded; rather the retirement cost (debit) is charged directly to expense before considering any ratemaking or the impacts of ASC 980.

Q. DOES ASC 410 DISTINGUISH BETWEEN THE ACCOUNTING FOR LEGAL ASSET RETIREMENTS VERSUS NON-LEGAL ASSET RETIREMENTS?

A. Yes. ASC 410 concludes that only legal AROs should be recorded in the financial statements at the time that the legal retirement obligation arises. Asset retirements, where there is no legal requirement associated with the retirement of the asset, were excluded from the accounting required by ASC 410. The FASB has paid increasing attention to the balance sheet presentation of assets and liabilities. The main thrust behind ASC 410 is to require that all legal liabilities of an entity are recorded on the Balance Sheet. Thus, the discounted value of the legal liability to remove an asset is recorded on the balance sheet of all entities at the time the legal obligation arises.

Q. WITH THAT BACKGROUND ON THE ASC 410 GAAP ACCOUNTING, HOW ARE SUCH COSTS GENERALLY TREATED IN THE RATEMAKING PROCESS?

A. Generally, regulators ignore ASC 410 for ratemaking purposes. Neither the ARO liability nor the ARC asset are included within rate base, and ARC depreciation and ARO accretion are excluded from operating expenses for determination of the revenue requirement. While the ARO liability and ARC asset are presented on the balance sheet, they result from accounting journal entries, not investor or customer contributions (and therefore are not considered for ratemaking purposes until the point that actual removal costs are expended upon the retirement of the asset).

Q. DOES THIS MEAN THAT LEGAL REMOVAL COSTS ARE NOT RECOVERED FROM CUSTOMERS IN THE RATEMAKING PROCESS?

A. No. Quite the opposite. As with all reasonable and prudently incurred costs incurred by a utility, costs to remove assets upon retirement are almost always recovered; however, the mechanism of recovery can vary. Sometimes these removal expenditures (referred to as "cost of removal " or "negative salvage") are recovered from customers over some period of time after removal expenditures are spent, and other times they are estimated and recovered from customers in advance of the actual expenditure through an estimated cost of removal concept - a regulatory mechanism that I will describe shortly. As a result, the ARC depreciation expense and ARO accretion that would be recognized in the income statement for a non-regulated entity are typically deferred as a regulatory asset for a regulated entity under ASC 980. This regulatory asset is reduced (amortized) upon recovery from customers via whatever mechanism is approved by the regulator.

Q. ARE LEGAL REMOVAL COSTS ALWAYS RECOVERED VIA COST OF REMOVAL?

A. No. As I mentioned previously, decommissioning of nuclear plants is a common utility ARO. Frequently, such costs are collected via a nuclear decommissioning surcharge which operates differently from the traditional cost of removal concept. For all costs, it is ultimately up to the regulator to determine if costs are prudently incurred and recoverable from customers. Once it is determined that a cost is prudently incurred and should be recovered, it is then up to the regulator to determine the method and period of recovery. This is an important point. Accounting does not drive cost recovery, but rather cost recovery drives the accounting under ASC 980.

Further, as noted in Company Witness Spanos's testimony, starting on p. 36:

"Witness Maness' testimony quotes from the Company's response to DR 147-3, 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 [147-1], 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 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 common 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.*

This response squares with my own experience with and understanding of industry practice."

Based on my experience, Mr. Spanos's characterization of how utilities generally treated the costs of CCR remediation for ratemaking purposes was consistent with industry practice prior to the enactment of the federal CCR Rule. Furthermore, prior to the issuance of the CCR rules, not recording an ARO liability for coal ash ponds was consistent with industry practice. As noted in Mr. Spanos's testimony, there was uncertainty surrounding the potential date or range of dates of retirements of the ash ponds, as it was considered likely they would continue to be used in future periods at the sites. ASC 410-20-25-7, 8 and 9 address these types of conditional obligations and acknowledge that there will be instances in which an entity does not have the information to reasonably estimate the fair value of an asset retirement obligation and that it is a matter of judgement dependent on an entity's relevant facts and circumstances. As such, it is not unusual that there was disparity in the timing of recording of ARO liabilities related to ash ponds due to each individual utility's facts and circumstances.

Q. DOES ASC 410 CONTAIN GUIDANCE ON THE RATEMAKING TREATMENT OF LEGAL ARO LIABILITIES OR OTHER NON-LEGAL COSTS OF REMOVAL?

A. No. ASC 410 and other FASB pronouncements do not address ratemaking treatment; ASC 980 addresses the accounting based on ratemaking treatment. However, ASC 410 acknowledges that many regulated entities recover asset retirement costs differently than how GAAP may recognize the related expense. Discussing rate-regulated entities, ASC 410 states:

> *"The amounts charged to customers for the costs related to the retirement of long-lived assets may differ from the period costs recognized in accordance with this Statement, and, therefore, may result in a difference in the timing of recognition of period costs for financial reporting and rate-making purposes."*

ASC 410 further recognizes that if the requirements for ASC 980 are met, the rate-regulated entity would recognize for financial accounting purposes a regulatory asset or liability for the differences in timing of cost recognition (and related recovery from customers) for ratemaking and financial reporting.

IV. COST OF REMOVAL

Q. WITH THAT EXPLANATION OF THE GAAP ACCOUNTING FOR LEGAL ASSET RETIREMENT OBLIGATIONS, CAN YOU TALK MORE BROADLY ABOUT REMOVAL COSTS AND THE ASSOCIATED RATEMAKING AND ACCOUNTING CONSIDERATIONS?

A. Yes.

Q. WHAT ARE REMOVAL COSTS?

A. Removal costs are the costs incurred at the end of an asset's useful life. At that time, there may be a salvage value, removal cost, or both. An example of salvage value is the amount realized from selling scrap metal resulting from dismantling a fixed asset. Salvage can be differentiated from the costs incurred by the Company to physically remove assets from service upon retirement, safely dispose of the asset and / or restore the site, which are referred to as removal costs (again, sometimes referred to as "negative salvage"). The FERC defines cost of removal as "the cost of demolishing, dismantling, tearing down, or otherwise removing retirements of utility plant, including the cost of transportation, and handling incidental thereto." Certain of these removal costs represent legal obligations. For example, certain sites contain asbestos and many transformers contain polychlorinated biphenyls ("PCBs"). There are environmental laws that govern the removal of asbestos and PCBs when the facility or transformer is retired, each of which comes with a cost. Certain removal costs are not legally required but are incurred for other reasons. For example, when utility poles are retired, they are physically removed from service although there is generally no legal obligation to do so.

Q. WHAT IS THE ACCOUNTING FOR PROPERTY, PLANT AND EQUIPMENT AND REMOVAL COSTS UNDER GAAP?

A. Under GAAP, the cost of an asset is capitalized and depreciated over its estimated useful life in a systematic and rational manner (generally on a straight-line basis), such that at the end of its useful life the plant asset has been fully recovered through depreciation charges. As previously stated, when the asset is retired, there can be a salvage value, a cost to remove or dismantle the fixed asset, both, or neither.

Based on GAAP, all entities need to consider salvage value when determining the annual depreciation charge. The definition of depreciation accounting under GAAP is as follows:

> *"The cost of a productive facility is one of the costs of the services it renders during its useful economic life. Generally accepted accounting principles require that this cost be spread over the expected useful life of the facility in such a way as to allocate it as equitably as possible to the periods during which services are obtained from the use of the facility. This procedure*

is known as depreciation accounting, a system of accounting which aims to distribute the cost or other basic value of tangible capital assets, less salvage (if any), over the estimated life of the unit (which may be a group of assets) in a systematic and rational manner." ARB No. 43 Paragraph 9-C- 5.

As noted above, depreciation accounting contemplates allocating the net original cost of the fixed asset (cost of the fixed asset reduced by the estimated salvage value) over its estimated useful life. For example, assume a fixed asset is acquired for $10,000 with an estimated five-year life and an estimated salvage value (at the end of year 5) of $500. The net cost to be recovered through annual depreciation charges is $9,500 or $1,900 each year ($9,500/5). In this manner, the net cost is allocated over the estimated useful life of the fixed asset and each period incurs an appropriate depreciation charge.

Q. DOES GAAP PROVIDE FOR RECOGNIZING THE COST OF REMOVAL OR NEGATIVE SALVAGE BEFORE IT IS EXPENDED?

A. No. GAAP does not have any standard that requires the cost of removal to be recorded for non-legal removal obligations prior to the removal being performed.

Q. THEN WHAT IS "COST OF REMOVAL ACCOUNTING?"

A. "Cost of removal accounting" is not a term that is defined in GAAP. Rather, I and others who are familiar with regulatory accounting, use this term to describe the ratemaking treatment approved by regulators in certain situations when the cost to remove an asset is recovered over the asset's useful life (and in advance of the actual removal expenditure) and the resulting accounting under ASC 980 for this regulatory mechanism.

Q. HOW DOES "COST OF REMOVAL ACCOUNTING" WORK?

A. Because regulators have granted recovery of cost of removal over an asset's life for certain assets, the regulator allows entities to include an advanced recovery of removal costs through additional charges to depreciation expense when developing the revenue requirement. As a result, ASC 980 allows regulated entities to recognize this "removal cost depreciation" for these assets for GAAP to match the revenue being collected to fund the eventual removal cost.

Q. IF THE REGULATOR ALLOWS FOR THE ADVANCED COLLECTION OF COST OF REMOVAL THROUGH "REMOVAL COST DEPRECIATION", HOW IS THAT ACCOUNTED FOR?

A. As previously noted, there is no GAAP that stipulates the accounting for "removal cost depreciation". Rather, ASC 980 matches the "removal cost depreciation" expense with the revenue requirement that considers "removal cost depreciation" as one of the costs of providing service. An example will help to clarify the accounting. Assume there is a cost basis of an asset of $100 with a 10-year life. Also assume there is a cost of $20 to remove the asset upon retirement. In this example, a non-regulated entity would depreciate the asset itself at $10 per year ($100 asset divided by a 10-year life equals $10 depreciation expense per year) and then recognize $20 of expense when the asset is removed. A regulated entity, only in situations where the regulator approves the recovery of the removal cost over the asset's life through cost of removal depreciation, would recognize $12 of depreciation expense per year (comprised of $10 depreciation charge per year to recover the $100 asset itself which was originally funded by investors plus $2 each year to recover, in advance, over 10 years, the $20 estimated cost of removal). While the investor's investment in Property, Plant and Equipment increases rate base, the cumulative "removal cost depreciation" recovered in advance from customers would reduce rate base until the removal is performed, at which time no incremental expense would be recognized as it was recognized over the asset's life.

Q. IF THE REGULATOR DOES NOT GRANT RECOVERY OF REMOVAL COSTS OVER AN ASSET'S LIFE, WOULD IT BE APPROPRIATE FOR THE UTILITY TO RECOGNIZE "REMOVAL COST DEPRECIATION"?

A. No. As I have stated, for regulated entities, accounting does not drive ratemaking; rather, ratemaking drives accounting. ASC 980 allows for a matching of revenue and expenses. If there is no revenue for the collection of cost of removal, there can be no "removal cost depreciation" as this would violate the concepts of ASC 980.

Q. CAN YOU PLEASE SUMMARIZE YOUR OVERVIEW OF ASC 410 AND "COST OF REMOVAL ACCOUNTING" AND HOW THEY IMPACT RATEMAKING?

A. Yes. First, accounting does not drive ratemaking; rather, ratemaking drives the accounting under ASC 980. All entities, regulated or not, must apply the provisions of ASC 410. However, if it is probable that a regulator will allow recovery of legal retirement costs for the associated assets at some point in the future, the ARC depreciation and ARO accretion costs are deferred as a regulatory asset. Once the revenues are billed to customers to collect removal costs, via whichever mechanism is approved by the regulator, then the expense is recognized at that point and the regulatory asset is reduced.

In contrast, "cost of removal accounting" is not specified in GAAP, but rather is reflected in GAAP financial statements as a result of ASC 980 to mirror the ratemaking approved by a regulator. Under this mechanism a higher depreciation expense is recognized to match the recovery of removal costs approved by the regulator. Such amounts are included in accumulated depreciation for ratemaking purposes; for financial statement presentation purposes, such amounts are reflected as a regulatory liability (for GAAP non-legal obligations) or netted within a regulatory asset account (for GAAP legal obligations to offset the regulatory asset recorded for deferred ARC depreciation expense and ARO accretion). Regardless of its balance sheet classification, the accumulated removal cost depreciation is included as a reduction to rate base because such amounts have been funded by ratepayers, and therefore ratepayers should receive the benefit of a return on amounts they have contributed.

V. SUMMARY OF DEP'S ACCOUNTING AND RATEMAKING FOR COAL ASH REMEDIATION

Q. CAN YOU PLEASE SUMMARIZE HOW DEP HAS ACCOUNTED FOR COAL ASH REMEDIATION COSTS PRIOR TO THE ADOPTION OF ASC 410 (SFAS 143) IN 2003?

A. Yes. I understand from discussions with DEP's asset accounting witness David Doss that prior to the adoption of SFAS 143, DEP did not recognize any assets or liabilities for coal basin closure costs or other legal obligations to remove assets. This was entirely appropriate as GAAP did not require any different accounting for legal obligations. Further, as the Commission had not approved any rate recovery associated with any such actual or anticipated coal ash basin closure costs, there were no ASC 980 entries to record.

Q. HOW DID DEP ACCOUNT FOR COAL ASH BASIN CLOSURE COSTS AS A RESULT OF THE ADOPTION OF SFAS 143 IN 2003?

A. Based on my understanding through discussions with witness Doss, consistent with other regulated utilities, DEP recorded its SFAS 143 accounting entries based on the laws in effect at the time of adoption. DEP concluded that no legal obligation existed at that point in time regarding coal ash basin closure. As a result, the accounting rules did not allow recording obligations for coal ash upon adoption.

Also, consistent with other regulated utilities, in relation to other situations where DEP had a legal retirement obligation at the adoption date of SFAS 143, such as for nuclear decommissioning obligations, DEP recorded a regulatory asset for the cumulative ARC depreciation and ARO accretion expense associated with those legal retirement obligations for amounts that would have been recorded historically (but not yet recovered from customers). ARC depreciation expense and ARO accretion were also recorded (added) in subsequent periods to this regulatory asset, offset by any recoveries of such costs from customers via previously approved removal cost depreciation.

Q. YOU SAID THAT TO RECORD A REGULATORY ASSET UNDER ASC 980, THESE COSTS HAVE TO BE PROBABLE OF FUTURE RECOVERY. HOW DID DEP SUPPORT THIS ASSERTION THAT SUCH RECOVERY WAS PROBABLE?

A. At the time of adoption of SFAS 143 in 2003, Progress Energy Carolinas, Inc. (the predecessor company to DEP) applied for an accounting order from the NCUC, which it received in 2003, signaling the Commission's intent to provide recovery of these legal asset retirement costs[2]. It is not uncommon to rely on an accounting order to support a regulatory asset if there is no prior conflicting precedent on point and the evidence supports the probability of recovery from customers in the future. In 2003, DEP concluded there was no such conflicting precedent here and that adequate evidence existed to support the recognition of a regulatory asset based on DEP's assessment that it was probable that the NCUC would provide for recovery of such costs.

[2] Docket No. E-2, Sub 826

Q. WHEN DID DEP FIRST REQUEST A MECHANISM TO RECOVER THE COSTS TO CLOSE ITS ASH BASINS?

A. In its 2010 depreciation study, DEP included estimated closure costs related to coal ash in the dismantlement study performed by Burns & McDonnell, a third-party engineering firm. As a result, upon the NCUC's acceptance of this depreciation study and the associated inclusion of these costs in rates (the study was effective July 1, 2012), DEP appropriately utilized "cost of removal accounting" for coal ash closure costs, whereby depreciation expense included the amounts approved for recovery in rates. The amounts collected under this regulatory mechanism were recorded to accumulated depreciation for ratemaking purposes (and reflected as a regulatory liability for GAAP financial reporting purposes) and therefore reduced rate base.

This study was performed prior to the passage of the Federal EPA's Coal Combustion Residual ("CCR") rules in 2015 and the North Carolina Coal Ash Management Act ("CAMA") in 2014. It was not until these laws were passed that DEP concluded that a legal obligation was created, and therefore ARO accounting under ASC 410 became applicable.

Q. DID DEP UPDATE ITS GAAP ACCOUNTING AND PROPOSED APPROACH TO THE RECOVERY OF COAL ASH BASIN CLOSURE COSTS AFTER THE PASSAGE OF THE CCR RULES AND CAMA?

Yes. The CCR and CAMA laws required DEP to perform certain closure efforts that would require significantly more investment than previously estimated. Further, as a result of the enactment of these laws, a legal obligation subject to the accounting guidance of ASC 410 was created. Thus, DEP appropriately recorded an ARO liability related to its required closure of coal ash basins to reflect this legal obligation at the time of their enactment. An offsetting ARC was recorded for any active plants. For plants that had been retired, the offset was charged to expense as is appropriate under ASC 410. This expense was then reversed / deferred as a regulatory asset in accordance with ASC 980.

In 2017, DEP filed a rate case requesting recovery of CCR and CAMA costs incurred (i.e., amounts spent for remediation of coal ash) from January 1, 2015 through August 31, 2017. In 2018, the NCUC approved recovery of these costs, net of amounts previously collected through cost of removal depreciation, over a five-year period, including a return on the unamortized balance[3] (the "2018 Order"). Further, this same order approved the Company's deferral of costs expended subsequent to August 31, 2017 until its next general rate case. It is my understanding that depreciation rates no longer included any negative salvage for coal ash basin remediation beginning on March 16, 2018 in conjunction with the effective date of the 2016 depreciation study.

Q. WHAT WAS DEP'S ACCOUNTING FOR THIS RECOVERY?

A. Based on my understanding, through discussions with witness David Doss, DEP has recorded all coal ash basin ARO accretion and ARC depreciation expense to an ARO regulatory asset. As cash is spent related to the requirements of CCR and CAMA, these amounts are reclassified from the ARO

[3] Docket No. E-2, Sub 1103

regulatory asset to a “spent” ARO regulatory asset, net of amounts previously collected via cost of removal accounting. The unamortized “spent” ARO regulatory asset balance accrues a debt and equity return. Once these remediation expenditures are recovered, either through cost of removal via depreciation expense (through March 16, 2018) or the five-year amortization period (which commenced on March 16, 2018) approved by the NCUC for the January 1, 2015 through August 31, 2017 expenditures, DEP reduces the “spent” ARO regulatory asset.

Q. BASED ON THESE ACCOUNTING AND RATEMAKING FACTS, WOULD IT HAVE BEEN APPROPRIATE FOR DEP TO CONTINUE TO FOLLOW “COST OF REMOVAL” ACCOUNTING FOR CCR COSTS SUBSEQUENT TO THE MARCH 16, 2018 EFFECTIVE DATE OF THE 2018 ORDER REFERENCED PREVIOUSLY?

A. No. Based on its 2018 Order, the NCUC indicated its intent to provide for the recovery of CCR and CAMA costs subsequent to August 31, 2017 on an “as spent” basis. Further, no amounts for future closure costs have been included in DEP’s current revenue requirement (i.e., negative salvage for coal ash was not included in the depreciation rates approved as part of the 2018 Order). As a result, it would be inappropriate to recognize any “removal cost depreciation” without the offsetting recovery in revenue from March 16, 2018 onward.

Q. ARE YOU SUGGESTING THAT THE NCUC CANNOT APPROVE RECOVERY OF CCR COSTS IN ADVANCE OF SUCH COSTS BEING SPENT?

A. Absolutely not. The NCUC can approve whatever regulatory treatment they desire within their statutory limits. The NCUC's history in this matter makes that point clear. From 2012 to 2018, the NCUC approved the recovery of coal ash basin remediation costs in advance of such costs being incurred via the NCUC's allowance for such costs through the cost of removal methodology (via removal cost depreciation expense). Beginning in 2018, the NCUC altered this approach by changing the ratemaking approach to allow for recovery of such costs after the fact (i.e., after the expenditure of funds for remediation). Specifically, from 2012 to 2018, the NCUC approved DEP's use of "cost of removal accounting" to recover amounts for coal ash remediation, and beginning in 2018, approved DEP's deferral of the amounts paid for such remediation to a "spent" ARO account for future recovery consistent with the 2018 order previously referenced. In other words, DEP's GAAP accounting appropriately reflected the ratemaking in place both before and after March of 2018. As I have consistently noted in my testimony, the accounting must match whatever regulatory treatment is approved.

Q. TO RECAP, COULD YOU PLEASE SUMMARIZE DEP'S GAAP ACCOUNTING BEGINNING IN 2012 RELATED TO THIS MATTER?

A. Yes. Perhaps example accounting journal entries will be helpful. All amounts are illustrative entries for operating plants and do not represent actual amounts recorded. In addition, note that my example ignores the allowed return on the unamortized balance of the "spent" ARO regulatory asset approved by the NCUC.

Entry #1: Recognize $100 of cost of removal through depreciation expense based upon recovery from customers in rates as approved by the Commission:

Dr. Accounts Receivable	100	
Cr. Revenue		100
Dr. Depreciation Expense	100	
Cr. Accumulated Depreciation		100[4]

Entry #2: Record ARO under ASC 410 upon the enactment of CAMA and the CCR rules:

Dr. ARC	5,000[5]	
Cr. ARO		5,000

Entry #3: Record ARC Depreciation and ARO Accretion Expense with offsetting ASC 980 entry to defer the expense recorded under ASC 410 (assuming amounts are probable of collection):

Dr. ARC Depreciation Expense	50	
Cr. ARC Accumulated Depreciation		50
Dr. ARO Accretion Expense	250	

[4] For GAAP financial reporting, this Accumulated Depreciation amount is reclassified to a Regulatory Liability account; however, for ratemaking purposes such amounts remain in Accumulated Depreciation and serve to reduce rate base.

[5] Note that the debit to this entry would have been to a regulatory asset account for any plants that were in a "retired status" at the time of the recording of the associated ARO (in accordance with ASC 980). For simplification of the example, I have assumed no such "retired plants".

Cr. ARO		250
Dr. ARO Regulatory Asset	300	
Cr. ARC Depreciation Expense		50
Cr. ARO Accretion Expense		250

Entry #4: Recognize the performance of a portion of the remediation efforts:

Dr. ARO	150	
Cr. Cash		150
Dr. "Spent" ARO Regulatory Asset	150[6]	
Cr. ARO Regulatory Asset		150

Entry #5: Adjust the accounts to net the removal cost accumulated depreciation (a regulatory liability) with the "spent" ARO Regulatory Asset:

Dr. Accumulated Depreciation	100	
Cr. "Spent" ARO Regulatory Asset		100

In this example, the net "spent" ARO regulatory asset is $50; this amount remains to be collected from customers and earn a return (represented as the difference between the "Spent" Regulatory Asset of $150 in Entry #4 and the Cost of Removal Accumulated Depreciation of $100 in Entry #1). As a result, upon the Commission's approval of the collection of the amounts previously expended, the final entry, excluding any impacts of a return on the unamortized balance, would be as follows:

[6] This accumulated amount represents the unamortized balance that, after netting with accumulated depreciation (entry #5) accrues an allowed debt and equity return as approved by the NCUC. Such entries to accrue a return have not been included in this example for simplicity.

Dr. Accounts Receivable	50	
Cr. Revenue		50
Dr. Amortization Expense	50	
Cr. “Spent” ARO Regulatory Asset		50

As can be seen in the example shown above, the ARO Regulatory Asset increases for GAAP accretion expense and ARC depreciation expense and decreases for amounts expended for remediation. The ARO Regulatory Asset balance does not earn a return nor does it impact ratemaking. In contrast, the “spent” ARO Regulatory Asset increases for amounts expended for remediation as well as for the accrual of an allowed return on the net unrecovered investor supplied funds (not shown in the above entries), and decreases based on amounts collected from customers as approved by the Commission.

Q. IS “COST OF REMOVAL ACCOUNTING” UNIVERSALLY APPLIED FOR “NORMAL” ASSET RETIREMENTS SUCH AS UTILITY POLES?

A. No. While the majority of regulators apply the ratemaking and accounting treatment for cost of removal as I have described, one outlier is the Pennsylvania Public Utility Commission, which has required certain jurisdictional utilities to capitalize incurred costs of removal as a regulatory asset after the removal occurs and has permitted recovery from customers over a future period. It has also required certain jurisdictional entities to capitalize the incurred costs of removal as part of the new asset being constructed and is depreciated / recovered over the life of the new asset. In either case, these costs are included in the rate base and earn a return as investors have financed these asset retirement costs. This example reinforces my primary assertion that for regulated entities, accounting follows ratemaking, not the other way around.

Q. HAVE YOU REVIEWED THE COMMISSION'S RECENTLY ISSUED ORDER IN THE DOMINION ENERGY NORTH CAROLINA ("DENC") CASE, DOCKET NO. E-22, SUB 562, ADDRESSING RECOVERY OF DENC'S COAL ASH BASIN CLOSURE COSTS?

A. Yes. I have reviewed sections of the DENC Order that address Findings of Fact Nos. 56-58, which specifically focus on DENC's accounting for CCR closure costs. On these issues the Commission decided:

- DENC did not account for CCR compliance costs as costs of removal in computing and requesting recovery of its allowance for depreciation expense.
- DENC's failure to incorporate such closure costs as part of its allowance for depreciation expense is contrary to accepted depreciation expense accounting principles.
- It is appropriate to require DENC to properly account for coal ash basin closure costs as part of costs of removal included in its allowable depreciation expense.

Q. WHAT IS YOUR REACTION TO THE COMMISSION'S ORDER IN THAT CASE?

A. While I am not familiar with the exact fact pattern in that case, nor am I familiar with the accounting practices of DENC, I have a different interpretation of

GAAP and accepted depreciation expense accounting principles. Assuming that DENC's accounting and ratemaking history is similar to that of DEP's as I have summarized in my testimony, DENC's accounting would be consistent with GAAP and accepted depreciation expense accounting principles. I am not aware of any accepted GAAP depreciation expense principle contrary to this practice. Consistent with my testimony, if DENC had not been provided recovery of the associated coal ash basin remediation costs, it would not be appropriate to include such costs in its depreciation expense recognized for GAAP as there would be no matching with the associated revenue for recovery of such costs. As I have previously stated, GAAP, through the application of ASC 980, follows ratemaking, not the other way around.

VI. CONCLUSION

Q. MR. RILEY, CAN YOU PLEASE SUMMARIZE YOUR TESTIMONY AND THE CONCLUSIONS YOU HAVE REACHED?

A. Yes. ARO accounting under ASC 410 is required for all entities, regulated and non-regulated. However, ASC 410 is typically ignored for ratemaking purposes as GAAP does not drive ratemaking. Rather, regulators generally approve either (1) "cost of removal accounting" which allows regulated entities to accrue "removal cost depreciation" expense to match amounts allowed in revenues (i.e., amounts are collected in advance of the cash expenditure for remediation), or (2) recovery of such cash expenditures after they are made, in which case a regulatory asset is recorded under ASC 980 if such expenditures are probable of recovery in the future from ratepayers. Amounts collected in advance of expenditures are typically recorded in accumulated depreciation (classified as a regulatory liability account for GAAP financial reporting purposes), which reduces rate base, while expenditures incurred prior to recovery are recorded to a regulatory asset (which either separately accrues a return or is added to rate base). DEP's accounting and depreciation practices as detailed in my testimony appear to be consistent with GAAP and historical practices with regards to regulated utilities.

Q. DOES THAT CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

MR. HESLIN: Thank you, Chair Mitchell.
Mr. Riley is available for cross examination.
CROSS EXAMINATION BY MR. GRANTMYRE:
Q. There is Bill Grantmyre with the Public Staff. Mr. Riley, on page 7, lines 3 and 4, you state:
"The prices charged by a rate-regulated utility are based on the utility's cost of providing service, including both capital and operating costs."
Would you agree that regulatory Commissions sometimes set rates that do not cover all prudently incurred utility costs?
A. Yes, I would agree.
Q. And one example would be that a percentage of senior executive salaries are sometimes excluded from rate recovery?
A. Yes, that is true. Although I would say that, for many utilities around the country, in many cases utilities follow a holding company structure. So some senior executives sit in the holding company as opposed to the regulated utility, so it really depends on the structure of the utility.
Q. But those senior executives, some of their had salaries would be allocated to the operating utility; is that correct?

A. That's correct.
Q. And you're aware that Commissions have disallowed or had some type of sharing of board of directors' compensation and expenses?
A. Yes.
Q. And also Commissioners have disallowed promotional advertising and lobbying expenses may be excluded from rate recovery?
A. Generally speaking, civic and political activities can be construed as what is called below the line, and therefore are shareholder costs, not ratepayer costs.
Q. And also the unamortized balance of nuclear cancellation costs have been denied a return, haven't they, even though they may have been prudently incurred?
A. I would need some specific examples on that.
Q. Well, Shearon Harris plant that was canceled, wasn't that denied a return back in the '80s? It was a construction plant.
A. I'm not familiar with that situation.
Q. And so there are situations when Commissioners do disallow, in ratemaking, prudently incurred costs, in summary?

A. I'm pausing because you're using the word "prudently." It really depends on the situation, but, in general, if there a disallowance, it's the view of the utility -- I'm sorry, the Commission that such costs were not prudently incurred.

Q. Well, payment to senior executives may be a prudent payment, but there's some sharing with the shareholders, correct?

A. Sure. You were referring to disallowance, so that's what I was explaining to you.

Q. Okay. Now, page 8, you discuss on lines 10 through 13, you discuss how SFAS 71, now ASC 1980 -- I'm sorry, 980, allowed certain costs to be deferred for future recovery instead of expense when incurred, correct?

A. That is correct.

Q. Are you aware that North Carolina is an historical test year jurisdiction?

A. Yes.

Q. And is it fair to say that in an historical test year jurisdiction, an unexpected utility expense would normally be deemed to be recovered in existing rates and not deferred?

A. For purposes of applying ASC 980, if a --

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there were various ways of deferring, or bases to defer incurred costs. ASC 980 specifically says that, if an entity determines that an incurred cost, an expense, is considered probable of recovery in the future from ratepayers, and that could be based upon past precedent at that particular utility, with other utilities, or by other means, then such amounts could be deferred as a regulatory asset, because they're, again, considered probable for recovery.

Q. But in ratemaking -- I'm talking about ratemaking rather than the accounting rules -- a utility expense that's incurred in a year would normally be recovered in existing rates, would it not, and not be deferred absent a deferral approval by the Commission?

A. Generally speaking, you would expect cost over service -- cost of service items to be recovered in the year that they're incurred.

Q. And would you agree that, in a jurisdiction like North Carolina, historical test year, the prohibition on retroactive ratemaking would normally bar a utility from recovering in future rates a past cost?

A. I'm not familiar enough with North Carolina law to answer that question.

Q. Do you agree that deferral is an exceptional regulatory tool that protects utilities from a significant drop in rate of return when there is a significant unexpected expense?

A. No. No, that's not the purpose of ASC 980. It's been mentioned in other testimonies. ASC 980 is effectively a matching of expenses with the recovery of those expenses from customers. And so it's in many cases either viewed as -- or Commissions look to either have costs recovered in a particular year or as they're managing rates over a period of time. But I would not call them exceptional.

Q. Are you familiar with General Statute 62-133 that sets out for the Commission what is to be included in rates?

A. I am not.

Q. Well, would you accept, subject to check, that ASC 980 is not mentioned at all in that statute?

A. Subject to check, certainly.

Q. And would you also accept that there's no mention of GAAP in that General Statute 62-133?

A. Subject to check, certainly.

Q. And would you also accept, subject to check, that G.S. 62-133 has no mention of FERC?

A. Again, subject to check, certainly, yes.

Q. Now, you explain that FASB standards apply to regulated utilities on pages 7 to 12.

Do you agree that, for state retail ratemaking, state law takes precedent over FASB standards if the two differ?

A. I would like to clarify that, when you're talking about state law, I believe you're talking about ratemaking and what to charge to ratepayers. GAAP, General Accepted Accounting Principles, in ASC 980 are financial reporting standards, accounting standards for financial reporting for entities such as DEC. And so one doesn't override another. I talk about it in my testimony. Accounting follows ratemaking. So as ratemaking and rates are established, the Company, for purposes of its financial reporting, must apply GAAP, including ASC 980, which would take into account those considerations as it relates to ratemaking.

Q. Now, would you agree that, without deferral, the ongoing accretion and depreciation expenses for ARO coal ash costs would not be recovered in an historical test year jurisdiction?

A. I'm sorry, you said without deferral, sir?

Q. Yes.
A. Yes, that is correct.
Q. So is it fair to say that, when a regulatory Commission allows a deferral of coal ash closure costs, it changes the ratemaking treatment that would otherwise have occurred under FASB ASC 410?
A. I'm sorry, sir, can you repeat the question again?
Q. So is it fair to say, when a regulatory Commission allows deferral of coal ash closure costs, it changes the ratemaking treatment that otherwise would occur under the application of FASB ASC 410; would you agree with that?
A. I would. But I'd just clarify, I got confused at the last part of your -- ASC 410 deals with accounting for asset retirement obligations. Ratemaking is outside of ASC 410. ASC 410 does not drive the ratemaking associated with asset retirement obligations.
Q. And I would turn you to page 10. You've already testified to some of this, but we'll go through it very quickly. Page 10, line 7 and 8, would you please read that into the record, the line 7 that begins with "the important point"?

A. Certainly.

"The important point here is that, for utilities, accounting follows ratemaking, not the other way around."

Q. And if we could go to page 12, lines 12 through 14, could you read that into the record?

A. Yes.

"The important point here is that the GAAP accounting for rate-regulated utilities follows the ratemaking process to reflect the unique economic consequences of rate regulation."

Q. And on page 17, line 16, can you read that first sentence beginning with "generally"?

A. "Generally, regulators ignore ASC 410 for ratemaking purposes."

Q. And also on page 21, line 4, I'll read the question if you could read the first two sentences.

"Does ASC 410 contain guidance on the ratemaking treatment of legal ARO liabilities or other nonlegal costs of removal?"

If you would read the answer.

A. Answer:

"No. ASC 410 and other FASB pronouncements do not address ratemaking treatment. ASC 980 addresses the accounting based on ratemaking treatment."

Q. And it also says, the next, line 6 and 7 -- could you read line 6 and 7?

A. "However, ASC 410 acknowledges that many regulated entities recover asset retirement costs differently than how GAAP may recognize the related expense."

Q. Now, on -- you're PricewaterhouseCoopers; is that correct?

A. That's correct.

Q. And on PricewaterhouseCoopers' audited financial statements, what is the sentence they use that says that the company complies with GAAP -- they issue an unqualified opinion that they comply with Generally Accepted Accounting Principles; what is that wording, do you remember?

A. Well, PricewaterhouseCoopers is a private company and we're not audited. But if you're asking --

Q. No. When they issue an audit opinion, I'm sorry.

A. Oh, I see, I see, yes. When we issue an audit opinion -- well, effectually -- and what an audit opinion is, is an independent audit firm, such as PricewaterhouseCoopers -- and we are, by the way, not the auditors of Duke. If we were to issue an opinion on DEC, for example, if it's considered unqualified, it means they're complying with Generally Accepted Accounting Principles and that the financial statements are fairly presented in all material respects.

Q. And the audit -- audit reports also have footnotes that explain unusual circumstances; isn't that correct?

A. I wouldn't call them unusual circumstances. In accordance with Generally Accepted Accounting Principles, there are required disclosures following all of the generally accepted accounting principles that apply to a particular entity, and that's what companies would include in their footnotes.

In addition, as a public company, the SEC also has additional disclosures that are required on publicly filed financial statements.

Q. But the Commission's ratemaking treatment on ARO costs can be described in a footnote very successfully in an audited financial statement; can it not?

A. Yes. For regulated utilities, there would be a footnote, typically titled regulatory assets and liabilities. And within there, there would be a description of regulatory assets and liabilities recognized.

Q. And that could explain the ratemaking treatment for the differential that may be different from GAAP or FERC; is that correct?

A. That's correct.

MR. GRANTMYRE: I have no further questions.

CHAIR MITCHELL: All right. Attorney General's Office?

MS. FORCE: No questions. Thank you.

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

(No response.)

CHAIR MITCHELL: All right. Redirect for the witness.

MR. HESLIN: Yes. Thank you, Chair Mitchell.

REDIRECT EXAMINATION BY MR. HESLIN:

Q. Mr. Riley, you received some questions from Mr. Grantmyre about ARO accounting, and in previous testimony we've heard about how the Commission or ARO accounting in this instance aligns with applications and orders related to coal ash recovery, and then the recognition in 2018 by the Commission that the Company had no choice in the matter but to use ARO accounting.

But can you explain the process for creating AROs, their requirements, and how it fits into the ratemaking process?

A. Certainly. So bear with me in terms of the discussion of journal entries. But when you step back, what FAS 143 required, and then FAS 143 became ASC 410, it required that for legal retirement obligations, that companies must recognize those legal retirement obligations on their books and records. Prior to the issuance of FAS 143, there was diversity in practice in terms of companies recognizing or not recognizing legal retirement obligations.

What the standard requires is that, to the extent that there's a legal retirement obligation identified, a company will look to estimate what that retirement obligation is. And that estimate will be based on what a third party would incur in terms of costs to perform that retirement obligation activity for the company. The company would then present value of those future retirement expenditures back to today's dollars and would recognize an obligation called a asset retirement obligation with an offsetting -- and that's it -- with an offsetting debit, an asset retirement cost.

Now, I think it's important to note that that asset retirement cost is not a separate asset of the company, but rather it's a part of the operating asset, the long-lifed asset which it's associated with. So in this case, it would be the coal plants. And FASB was very specific on this point. They viewed that the asset retirement obligation was integral to our prerequisite for -- for operating the long-lifed asset. It was not a separate asset, but it was part of the overall long-lifed asset.

And then what would happen is, is that asset retirement cost, the asset, would be amortized over the life of the operating asset. The obligation, which I mentioned, which is present valued, would be accreted into the future. Accretion expense would be incurred every year to increase the obligation as you came closer and closer to those retirement activities.

Both of those items would be reflected as expense, annual expense, a period charge within a company's financial statements.

Separately, what has to happen is then a company would if it was a rate-regulated entity, would make a determination as to whether or not those expenses are recoverable from ratepayers in the future. And standard there is, is it probable of recovery from ratepayers in the future? Not guaranteed, but probable, which is generally 75, 80 percent, in terms of a percentage.

If it's deemed probable, then it would result in the company recognizing a regulatory asset and reversing the expense that was recognized under the ARO accounting for that year. And so you would end up with a regulatory asset. That regulatory asset would only get reversed when those -- when that amount was actually recovered from ratepayers.

I'd like to -- I'm sorry, you were on mute. But maybe I just want to make one clarifying point. At the time a company estimates its ARO or its asset retirement obligation, that represents an estimate. An estimate of what a third party will incur to perform those retirement activities. Even if the company will perform them on its own, but it has to be in the eyes of a third party.

Separately, it's an estimate, and estimates can change over time based on changes in facts and circumstances, changes in technology. In addition, there can be multiple scenarios in terms of how retirement activities are performed. If that was the case, then the utility would apply a probabilistic model to come up with that asset retirement obligation.

But the key point there is, is that overall, this asset retirement obligation is an estimate. And to the extent that the estimate changes, it would be recognized in that period as a change in estimate.

Q. Okay. So it would be fairly typical for those estimates to change over time; is that correct?

A. Yes. Excuse me.

Q. That was a yes?

A. Yes. Yes.

Q. And you talked about when the initial retirement cost is established and its connection to the facilities, and you also -- you've heard testimony or the standard of used and useful.

Can you talk about how -- in creating or establishing that initial retirement cost, how that can relate to the idea of used and useful?

MR. GRANTMYRE: I object. I don't remember any cross examination on the terms used and useful. This is Bill Grantmyre.

MR. HESLIN: The questions -- the cross

examination by Mr. Grantmyre was about ARO accounting. I'm talking about a facet of ARO accounting, and in particular, the initial retirement costs. And so I'm asking a question that is very related to cost, it just wasn't -- the three words "used and useful" weren't included in your cross.

CHAIR MITCHELL: All right. Mr. Heslin, I'm going to overrule the objection. I'll allow the question to proceed, but please stick to redirect.

MR. HESLIN: Yes, Chair Mitchell.

THE WITNESS: So maybe going back to what I said earlier, that the FASB looked at that asset retirement cost as being integral to the operating asset, itself. In this case, the coal plant. The coal plant was deemed used and useful and was a recoverable cost for ratepayers.

The one point that I would like to highlight, and it was just mentioned in my testimony, that ASC 410 is typically excluded from ratemaking. The reason for that is because, in many cases, there hasn't been a cash outlay associated with the asset retirement obligation.

So in this case, although the asset -- asset retirement cost has been recognized, there hasn't been a cash outlay as yet related to the retirement obligation efforts.

And therefore, what we typically see, what I typically see across the country is that that asset retirement cost and obligation are excluded for purposes of rate base, and instead are recovered in the future as the company gets closer to its retirement activities or gets beyond its retirement activities.

Q. Thank you, Mr. Riley. And kind of following up on that, Mr. Grantmyre walked you through certain parts of your testimony where you state very clearly that you recognize the principle that accounting follows ratemaking. But I'd ask you to provide a little context for those statements in your testimony and why that applies here within the context of the coal ash expenses and costs that we're talking about.

A. Certainly. So it is a favorite phrase of ours in the utility world, and really what it's meant to say is that Commissions have a lot of latitude, obviously, in terms of setting rates. For purposes of financial reporting, what ASC 980 does, GAAP accounting, it recognizes the effects of how rates are established by a Commission. Not the other way around. The accounting comes after rates are determined.

And the consequences of that can be, as we talked about earlier, a deferral of expense, because that expense could be recovered in the future rather than as a -- in the period that it's incurred, it could be recovered in the future from ratepayers, and therefore the accounting would defer the expense. Similarly, if a company were to recover monies ahead of incurring a cost, as is in the case of cost of removal, for example, it could result in establishing an obligation, a regulatory liability is what we call it, to be carried on the books of the financial statements.

But it's an important point that, for financial reporting purposes, the Commission sets rates, and then for financial reporting purposes, you reflect the impact of those decisions in the financial statements of the Company.

Q. And I think you might have touched on it with that answer, but I just want to be clear. Mr. Grantmyre asked you to turn to page 21 in your testimony when he was going through the series of questions about certain statements about ASC 410 in your testimony. And on line 6 and 7 of page 21 of your prefiled rebuttal testimony or your rebuttal testimony, it states:

"However, ASC 410 acknowledges that many regulated entities recover asset retirement costs differently than how GAAP may recognize the related expense."

Do you have any further context or explanation for that statement, or have you covered that?

A. Just to clarify that point, what we see at utilities across the company -- the country, really what's getting at here is that, as I talked about earlier, over time, that asset retirement cost would be depreciated, and depreciation expense will be recognized. Similarly, the asset retirement obligation, because it has been present valued, must accrete over time up to the ultimate obligation that needs to be relieved. And so that accretion expense and that depreciation expense will be recognized in the financial statements of a company.

To the extent that it's probable that that depreciation expense and accretion expense will be -- is probable of being recovered from ratepayers in the future, then that expense would be deferred and the company would recognize a regulatory asset for those costs.

Q. And is that similar to what has happened here in this instance, or is it different?

A. It is similar. This is exactly how Duke has applied the accounting at DEC. And I would say it's -- in my experience working with utilities across the country, this is -- this is very consistent with what I see across the country.

Q. And in addition, Mr. Grantmyre, when he was walking you through the ratemaking statute, he highlighted the -- that GAAP and FERC were not contained or included in the texts of that statute. But to the extent that there are industry -- those are industry standards that apply to utilities such as DEC, do you have an opinion on whether deviations from those standards in different jurisdictions could have an impact on companies or the industry as a whole?

A. Well, I haven't -- I haven't read what was referred to, that -- the statute. It's not surprising to hear that it doesn't refer to GAAP or FERC, because, from my understanding and what I'm hearing, that relates to ratemaking and how rates would be established. Which is completely -- as I said before, it's completely separate from financial reporting purposes. Financial reporting would be applied after the ratemaking is determined.

Now, I point out that we've talked about deferral of expenses for future recovery. If for some reason that these costs were deemed not to be recoverable, then that would result in a charge by the Company for disallowed costs. So that's the flip side to what we're talking about, for financial reporting purposes.

Q. And you wouldn't be surprised to know that Rule 8-27, North Carolina Utilities Commission Rule 8-27 requires the FERC Uniform System of Accounts of utilities, but -- would you?

A. No, that would not surprise me.

Q. And then from an accounting perspective, is there a bright line rule that dictates whether an activity is always capitalized or always expensed, or is the end purpose of that activity what governs the accounting?

MR. GRANTMYRE: I would object. I don't remember asking any of these questions about what's capitalized and what's not.

CHAIR MITCHELL: All right. Mr. Heslin, can you tie this to cross examination of your witness?

MR. HESLIN: Once again, it's just the general accounting principles that are inherent in the ARO. There's obviously been testimony before this about the ARO, and those costs coming out of ARO as whether they were expenses or some other category, and so these are redirect related to that facet of the -- of the testimony.

CHAIR MITCHELL: All right. Mr. Heslin, I'm going to allow -- I'm going to overrule the objection. I'm going to allow the question to proceed, but I'm going to ask you one more time, let's stick to redirect here.

MR. HESLIN: Thank you, Chair.

THE WITNESS: To answer your question in the context of ARO accounting, I would say it is unique. If I go back to my initial statement, when a company makes an estimate of a legal retirement obligation, it records an asset retirement obligation and an associated asset retirement cost. Again, that's an asset. You say what is that asset comprised of? It's comprised of the estimate of future retirement activities associated with legally retiring that asset, whatever that means in that particular context.

And so it's retirement activities in this case that are getting capitalized on a present-value basis. So it's very unique as it relates to ASC 410 as compared to other GAAP that you might point to in terms of capitalization of property plant equipment versus recognition of period costs. ASC 410 is very specific in terms of how that asset retirement cost is built up.

Q. Thank you, Mr. Riley.

MR. HESLIN: Chair Mitchell, I have no further redirect at this time.

CHAIR MITCHELL: All right. Questions from Commissioners, beginning with Commissioner Brown-Bland.

COMMISSIONER BROWN-BLAND: I don't have any questions.

CHAIR MITCHELL: All right. Commissioner Gray?

COMMISSIONER GRAY: No questions.

CHAIR MITCHELL: Commissioner Clodfelter?

COMMISSIONER CLODFELTER: Nothing.
CHAIR MITCHELL: Okay.
Commissioner Duffley?
COMMISSIONER DUFFLEY: No questions.
CHAIR MITCHELL: Commissioner Hughes?
COMMISSIONER HUGHES: Yes.
EXAMINATION BY COMMISSIONER HUGHES:
Q. Just a clarification question. In your testimony you talk a lot about best practices or practices you've seen across the country. I realize there's a lot of unique things going on here. But I just wanted to get a better understanding of how what's being talked about in North Carolina relates to both the accounting standards and what you see in other jurisdictions. I think what the Public Staff is proposing in a lot of ways with this equitable sharing is not occurring through an accounting treatment, but it's occurring through a ratemaking treatment with the assignment of a rate of return.
And I just want to clarify that, that is what the Public Staff is -- has talked about by looking at a future net present value and coming up with some sort of net present value of option one versus option two. I'm not sure if you've looked at the economic analysis

that the Public Staff is requiring, but that's what I see -- think they're requiring. That's what they're proposing, is option one versus option two, and they get to their equitable sharing by comparing option two to option one. But I think both of those options are economic analyses, they're not accounting treatment.

So I'm trying to understand, from an accountant's perspective, and an ARO accounting perspective, can what the Public Staff is proposing be done without involving any kind of changed accounting? In other words, if the rate of return is set at a ratemaking period, and that's known and that's moving forward, that all can be done within the confines of this ARO accounting standards; can it not? I know that was a long question. I'm happy to try and clarify it.

A. No, sir. I understand your question. Maybe I can try to respond, and then if I don't fully respond, you can follow up with a question.

I understand your point around an economic analysis. If I were to step back as just an accountant thinking about this situation, as I think about any sort of recovery of cost, recovery of an asset, what I have to ask myself is: Based on the accounting standards, is the Company receiving full recovery of its costs, and by the way, if it's actually been out-of-pocket cash, getting a return, an allowed return as well on those costs, or is it something less? If it's receiving something less than a full return, a full recovery of and on costs that it has expended, then that would be viewed as being a disallowance.

It can be an explicit disallowance or an implicit disallowance. And there are accounting standards that drive disallowances. So to the extent that a utility expends $1,000, for example, and is not allowed recovery on and of that $1,000, say the regulator determines that it will only allow recovery of $800 over a five-year period, or say the utility is only allowed recovery of $1,000 but over a five-year period, in both of those situations, an auditor would look at that and say there's been an explicit or an implicit disallowance of costs. And that disallowance would be recognized immediately, as opposed to over time.

So there are accounting consequences associated with -- call it an economic analysis that results in a sharing of costs. That sharing what the rate -- what the shareholder is called -- is absorbing, it's recognized immediately.

Q. So with that -- with that explanation, what do accountants use as the default rate of return for calculating the disallowance? Is that -- isn't that set at rate setting time, or is there some sort of standard that you use for the default?

A. It can depend on the situation, but in the case of a company using its general funds, in this case you would say for ash -- coal ash remediation, generally it would be the weighted average cost of capital.

Q. So that's what you would -- that's what you would use kind of as the default rate?

A. That's correct.

Q. Okay. And then if I can just understand -- just this is a basic question. When you were talking about -- a number of times I think I heard that you said that these ARO assets are very difficult to map over to physical assets. Is that true? I mean, if I had -- if there's an asset on the book that is actually a physical asset that I could go see versus an ARO asset, that if I follow the way those were treated, I would see a number of differences? I mean, the ARO asset gets on the books before the physical asset is even there before a dollar's even been spent; is that correct? But that wouldn't happen with the physical asset?

A. I apologize if I was unclear earlier. So you have the creation of an actual physical asset. Let's use the coal plant in this example. The coal plant is built, you have a physical asset. The Company has determined that there is a legal retirement obligation driven by CAMA, driven by CCR, and therefore it must recognize an asset retirement obligation and an associated asset retirement cost, an asset.

The FASB -- the Financial Accounting Standards Board does not look at that asset retirement cost as being some separate intangible asset. It's not a separate asset, but rather, that asset retirement cost is part of the coal facility, itself. It's part of that operating long-lived asset. And that asset retirement cost would be amortized over the life of that coal asset.

So depending on what asset retirement obligation you're talking about, you can have different asset retirement costs that are mapped to different assets that created that legal retirement obligation.

Q. But from a -- from that standpoint, if I'm looking at a coal plant, I'll see a lot of physical things made out of concrete and steel. They will be getting a rate of return on that asset being shown up. Then over here to the left I have to visualize a bunch of future trucks carting -- carting ash away, and that's this untangible asset. That part of the asset has a value but doesn't exist yet. There's not a truck moving forward.

Does that part of the asset -- is that earning a return in the same year that the physical parts of the asset are earning a return?

A. That's a good question, and that gets into my point around the cash. At the time that asset retirement cost is recognized, the utility is not out-of-pocket cash. In your words, the trucks haven't started coming in to remove those assets. And so as a result, that asset retirement cost and obligation for ratemaking purposes are typically excluded from rate base. And if you follow Duke's accounting, what happens is, bear with me, that asset retirement cost is depreciated, that asset retirement obligation is accreted, expense is recognized on an annual basis. Duke takes the position that it's probable that those expenses are recoverable in the future from ratepayers, so it reverses that expense and records a regulatory asset. Now, at that point, it's still not out-of-pocket cash, so they record the regulatory asset, but they do not earn a return on that regulatory asset.

At a future point in time when they start expending monies, now cash is actually starting to flow, they reverse that regulatory asset and record a regulatory asset, I think they call it a spent regulatory asset, to designate amounts recoverable from ratepayers for which they are out of pocket cash. They have used shareholder funds, and as a result should earn a return on that spent regulatory asset. I hope that answers your question.

Q. I have it now. And you wrote some of that in your testimony and you answered that before, I just needed to hear it three times. Thank you. No further questions.

A. Thank you.

CHAIR MITCHELL: All right.

Commissioner McKissick?

COMMISSIONER McKISSICK: Just one or two brief questions.

EXAMINATION BY COMMISSIONER McKISSICK:

Q. Mr. Riley, with Pricewaterhouse, you

obviously provide similar comparable services as to what you're doing in this case to utilities across the country; is that correct?

A. That is correct.

Q. So let me ask you this, because we've been focused so much on what Duke is doing or the way they've handled things. In other jurisdictions that had the, you know, used coal as the way of generating electricity, they had the coal ash ponds or impoundments, in those other jurisdictions that you are familiar with, are they wrestling with these same types of issues at this time in terms of accounting in the way they're establishing things?

A. In my opinion, no. No.

Q. They're not in other places? What did they do in other jurisdictions to handle things differently in terms of potentially treating the coal generation facilities in a way to know that when they came to their end and they had these impoundments to deal with, to go ahead and put aside reserves for addressing it?

A. Generally speaking, it's how I just described it a moment ago where -- where, generally around the time that CCR was issued, those asset retirement obligations and related asset retirement costs were recognized, they followed asset retirement obligation accounting, depreciating and accreting the asset liability, deferring the expense. And then regulators in a particular jurisdiction, really in the context of setting rates for that jurisdiction, had to decide at what point they allow recovery of those expenses, over what period of time.

Q. Thank you. I don't have any further questions.

CHAIR MITCHELL: Mr. Riley, I have one question for you.

EXAMINATION BY CHAIR MITCHELL:

Q. In response to questions from Commissioner Hughes, you indicated that, if there is a disallowance, whether it be implicit or explicit, that disallowance is recognized immediately and not over time; did I understand your testimony correctly?

A. That's correct.

Q. Okay. And so can you then sort of -- so then what happens? If the disallowance is recognized immediately, what is the significance to the Company? Help me understand sort of the rest of the situation.

A. Sure. Let me go back to my example, which was say there's a $1,000 asset and a commission chooses to allow only recovery of $800 of that asset over a five-year period. So that translates into -- or we'll make it a four-year period, make the math easy. So instead of recovering $250 a year, they're going to recover $200 a year.

What GAAP -- what I'm getting at related to the disallowance and the immediate recognition of that loss is that GAAP does not want to defer that loss. It's a known loss. You're going to not recover $200. So why defer that loss and recognize it evenly over a four-year period? It needs to be recognized today.

Now, the impact of that would be a charge to the financial statements of the utility, and it would impact the Company's net income in that period. Now, I would also say, just qualitatively thinking about it as a person that works in the utilities sector, from the financial side, to the extent that there's a disallowance, that raises concerns related to regulatory uncertainty, and that creates concerns around credit and other potential issues associated with the Company that could obviously impact the Company's cost of capital.

Q. All right. Thank you, Mr. Riley.

CHAIR MITCHELL: All right. Questions

on Commissioners' questions, beginning with the Public Staff?

MR. GRANTMYRE: Yes. This is Bill Grantmyre again, on Commissioner Hughes' questions.

EXAMINATION BY MR. GRANTMYRE:

Q. Has DEC in this case proposed to include in rate base any portion of the balance of the asset retirement cost asset?

A. I don't believe so, sir, but I would -- I would say that that's more of a question for the Company to confirm.

Q. Are you aware that DEC is trying to include in rate base only a portion of the deferral of depreciation and accretion expense?

A. I think that they're looking to include the spent regulatory asset that I mentioned earlier.

Q. Thank you, that's all I have.

CHAIR MITCHELL: All right. At this point we are going to --

CHAIR MITCHELL: All right. Let's go back on the record, please. We are on questions on Commissioners' questions for Mr. Riley. Mr. Grantmyre had just finished his questions. Let me check one more time to see if any other intervening parties have questions on Commissioners' questions for the witness?

(No response.)

CHAIR MITCHELL: All right. Hearing none, Mr. Heslin -- oh, Ms. Townsend, did you --

MS. TOWNSEND: I was just saying no questions from the Attorney General's Office.

CHAIR MITCHELL: Okay. Thank you, Ms. Townsend.

All right. Mr. Heslin, you're up.

MR. HESLIN: Thank you, Chair Mitchell.

Whereupon,

SEAN P. RILEY,

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

EXAMINATION BY MR. HESLIN:

Q. Mr. Riley, Commissioner McKissick asked you whether other states were wrestling with these coal ash recovery issues, and you said no.

In your observations, how are other jurisdictions handling coal ash recovery?

A. In general, what I observed is that they have not followed cost of removal accounting. What they followed is just traditional ARO accounting. Similar to how Mr. Doss described their ARO accounting at DEC. To the extent that expenditures are made, companies are recording regulatory assets and earning a return on unrecovered regulatory assets. I think that's, in general, what I'm seeing.

Q. Are you aware of any jurisdictions that have approved or adopted an equitable sharing theory with significant disallowances such as that proposed by --

A. No. No, I'm not aware.

Q. And based on your review of coal ash recovery decisions across the jurisdictions, why have these other jurisdictions not wrestled with this coal ash accounting ARO issue?

A. I would respond by saying that, clearly, these are costs that need to be dealt with, and Commissioners are looking at over what period will they be recovered from ratepayers. And, in general, you see them being recovered more towards the retirement activities occurring. So, in other words, you're not recovering it through cost removal in advance, but rather in later periods. So it's more of a timing of recovery question for Commissions as opposed to whether costs should be recovered.

Q. And are the other jurisdictions allowing recovery of and on these coal ash costs?

A. We haven't seen -- and I mentioned disallowances earlier. We haven't seen disallowances in this area, so the answer to that is yes.

Q. And Chair Mitchell asked you questions dealing with accounting -- the accounting perspective of potential regulatory disallowances.

If the Commission were to adopt the Public Staff's equitable sharing theory, which it denied in the prior DEC rate case, but in this case disallowed billions of dollars of recovery in coal ash costs, in your opinion based, on your experience and observations, what would be the perception of and the impact to the Company?

A. Well, maybe we can start with the impact to the Company financially. Obviously, there would be, as I talked about earlier, a charge to earnings immediately in the income statement, and that would flow through to a significant reduction in equity of the Company. Ultimately, the strength of the financial position of the Company would be severely impacted given that dollar size or the magnitude of that level of disallowance.

In terms of the perception, you have to think about it in terms of investors. Investors are comparing regulated utilities across the country. They have choices to make in terms of who they invest in. And they compare one utility versus another, and in terms of perceived risk. So the question investors would ask is: Is the regulatory compact in North Carolina working? Is there greater risk in North Carolina as compared to other utilities elsewhere in the United States?

And with that level of a disallowance, it's reasonable to assume that they would perceive a greater level of risk. And as a result, if they were to invest in Duke, they would expect a higher level of return. So all things being equal, they would expect a higher level from Duke than from others. The impact of that is that it would increase the overall cost of capital of Duke, which when you think of ratemaking theory, that ultimately would result in increased rates to

North Carolina customers.

MR. HESLIN: Chair Mitchell, I have no further questions.

CHAIR MITCHELL: All right. I actually have one additional question for the witness.

EXAMINATION BY CHAIR MITCHELL:

Q. Just that we are all clear, when you say "cost of removal accounting," can you explain exactly what you mean by that?

A. Certainly. I'm sorry I was unclear. Cost of removal accounting is -- is a mechanism that is employed by regulators to allow for recovery of retirements in advance of them occurring. So it's just a matter of being able to build up a reserve to be able to pay for the retirement when it happens. You typically see, and I think Doss talked -- witness Doss talked about this related to nonlegal retirement obligations.

The point around cost of removal is that you're recovering costs in advance of the actual expenditures from ratepayers; i.e., building up a reserve. And typically what you see as it relates to the AROs that we're talking about is that they're typically recovered after the expenditures occur from ratepayers, as opposed to recovering it in advance.

CHAIR MITCHELL: All right. Thank you, Mr. Riley. Any questions on my question just asked of Mr. Riley? And I actually see Commissioner Duffley with her hand raised, so she must have an additional question for the witness as well. So I'll let Duffley proceed, and then we'll take questions on my question and Duffley's questions.

COMMISSIONER DUFFLEY: Thank you, Chair Mitchell.

EXAMINATION BY COMMISSIONER DUFFLEY:

Q. I just would like to clarify the record with this question. So you mentioned that the disallowance is recognized immediately, and then I thought I heard a response that could be billions of dollars. But is the disallowance just related -- so let's say, hypothetically, there was a disallowance in this case. The full recognition would only be for the costs sought in this case, it would not be for the entire estimated ARO, correct?

A. I'll try to answer your question with an example. If the utility were seeking -- were in need to recover $1,000 -- just going back to my earlier example -- to recover a $1,000 asset, and the Commission were to conclude that it could only recover $800 of that $1,000 asset, and say they said they could recover it over a four-year period with a return, then in that case, the disallowance in my example would be $200.

Q. Okay. I understand that. Let's just use hypothetical numbers. Let's say that the estimated asset retirement obligation is $1 billion, but the utility comes in for a rate case as they spend, deferral and spend, and let's say, in case number one, they come in and seek $500 million. And the regulatory agency disallowed 50 percent of that $500 million.

The Company's then not required to recognize a full loss on that $1 billion; it would just have to immediately recognize the disallowance of $250 million; is that correct?

A. Excluding considerations of return. The immediate disallowance with the explicit disallowance in your example would be $250 million. I think then what the Company would need to assess is, is it exposed to non-recovery of the remaining $500 million; what caused the $250 million charge on the first $500 million. So it would have to consider the potential ripple effect on the remaining balance as well.

Q. Okay. But that would be in the context of the credit metrics versus accounting?

A. No, it's an accounting consideration. So if they needed to recover $1 billion, they were only going in for the first $500 million, and there was an order to say share the first $500 million, 250 and 250, the Company would need to say is it probable that we'll recover the remaining $500 million, or do we think it's likely that we'll have a charge -- actually, is it probable that we will incur an additional disallowance on the remaining $500 million? In which case, if it concluded that it was probable that it would also have a disallowance on the second $500 million, it would also have to accelerate that charge as well.

Q. At that point of the first disallowance?

A. That's correct.

Q. Okay. Thank you for that explanation.

COMMISSIONER HUGHES: Commissioner -- I mean, Chair Mitchell, before you go, I have a question based on these questions too.

CHAIR MITCHELL: All right. You may proceed, Commissioner Hughes.

EXAMINATION BY COMMISSIONER HUGHES:

Q. Mr. Riley, you referred to the word "disallowance" a number of different times, and you've used an example of, you know, $1,000. From what I understand here, the, quote, disallowance that the Public Staff is requesting, again, is a net present value disallowance. So it's a disallowance of a net present value in some cases over 25 years. So what I can see on a cash flow diagram that they presented is -- you know, they're disallowing amounts way into the future.

And I'm just curious, again, your example of it being shown right away, and you gave an example of $500 million and $250 million is disallowed. Could you just say how it would work mathematically, if it instead was $500 million was sought after and $500 million was granted, but over a period of time that caused a net present value disallowance? That's just way into the future, and I'm having a hard time wrapping my head around what would actually show up today. Does that make sense?

A. Yes, it does. I'll try to answer your question. So in your example, if the Company's seeking $500 million in recovery and they're granted

$500 million in recovery, except if the Company is out-of-pocket cash today $500 million and they're not going to recover that for, say, a period of time, call it 25 years, they have used shareholder monies today, and shareholders expect a return on the use of their funds.

So to the extent that the Commission were to only grant recovery over a 25-year period, $500 million, in present value dollars it's something less than $500 million.

Q. Okay.

A. And what the accounting would require is for the Company to assume or to assess what return would it have expected to get on those dollars, and I would have expected weighted average cost of capital. They would present value of those dollars back to today's dollars to today. Using your example, say that discounts back to $400 million. They would take a charge of $100 million for that implied disallowance in accordance with the accounting standard.

So, in effect, because they're not getting a return on their money, that has to be recognized today as a charge.

Q. So what you're saying is the net present value of the difference between the assumed return by standard accounting has to be calculated and charged off in the next calendar year?

A. That's right. In other words, if the Commission were to allow a recovery of but not on assets that were the result of expenditures, there's an accounting consequence for the conclusion that they should not get a return on expended funds, and that's called an applied disallowance.

Q. So -- but figuring out -- figuring out the amount of that disallowance, then you have to, again, have the default, and you're saying that you would use a weighted average capital. Is that in the discretion of the Company or the audit firm to decide what is the default for calculating that net present value? Because when you're talking about net present value, people are throwing around all different types of discount factors.

A. No. There are specific accounting standards on exactly how that accounting would work. And so the Company -- it's the Company's books and records would apply, and forgive me, I don't remember the ASC reference, but it's the accounting standard number 90, FASB 90. The Company would apply that to calculate the disallowance. So it's specific right in the accounting standard.

Q. What did you say that was again, that accounting standard? Can you repeat that?

A. It's SFAS 90, I believe.

Q. Thank you.

CHAIR MITCHELL: All right. Thanks, Commissioner Hughes.

COMMISSIONER HUGHES: No further questions.

CHAIR MITCHELL: I see Commissioner McKissick has a question.

EXAMINATION BY COMMISSIONER McKISSICK:

Q. And it's simply this: I mean, I raised the question earlier about what other utilities were doing, in terms of addressing issues similar or comparable to this, and whether they had -- how they had addressed it from an accounting perspective.

The thing I'm curious in knowing is simply this: In light of the history of what was going on with coal ash and the ability to know that these facilities were going to have to be retired at some point, we later see the CRR rule being adopted, I mean, what exactly can you tell me other utilities were doing that Duke did not do that perhaps was not wise in hindsight?

A. I guess my answer to that question would be that I don't see Duke doing things that are different than other utilities are doing. Every jurisdiction, regulators are dealing with rates in an overall context, in terms of managing current rates versus future rates, dealing with known costs, dealing with estimates, dealing with things currently versus pushing them off into the future, depending on how questionable certain estimates are. I would say that I don't see Duke doing things differently than what I've seen elsewhere.

Q. And at what point in time were most of these entities beginning to, you know, handle their accounting in a way that adequately would allow them to accumulate funds to address the coal ash impoundment issues, you know, in advance of the way we're approaching it here in North Carolina?

A. Well, in terms of the accounting, essentially, utilities really didn't recognize their asset retirement obligations until CCR came out. Your CAMA came out slightly before CCR, so you -- I say "you" being Duke started to make their estimates of its asset retirement obligations at that time.

And then, as I mentioned, generally speaking, utilities were deferring the expense that was being recognized as a period expense, the depreciation and accretion to be recovered in the future, and that recovery period was generally after expenditures were being made for utilities.

Q. Okay. And are you familiar with the estimates that Duke obtained as it related to retirement of their coal-generating assets?

A. In terms of the specifics of the calculation, no, I haven't reviewed those estimates.

Q. You have not. So you're familiar with them in general, in terms of what the total projected dollar value would have been, I take it; is that correct?

A. Correct.

Q. And were other utilities basically taking these issues into account significantly in advance of the adoption of CRR [sic]? I mean, from what I read, they were.

A. In terms of the -- in terms of the recognition of the obligation?

Q. Uh-huh.

A. No. No, the obligations were generally recognized as a result of CRR -- CCR.

Q. Okay. So you were not saying nationally recognition of what those potentially contingent liabilities would be, for lack of a better way of saying it, in advance of the CRR's [sic] adoption?

A. That's correct. To the extent that utilities did recognize the liability prior to CCR, was a very -- typically a very minor amount, and it was increased significantly at CCR.

Q. And based upon what was going on, in terms of coal ash and in terms of groundwater contamination or the potential for it, do you think that it would have been wise for Duke or for other utilities to have gone ahead and established those reserves in advance of the adoption of CRR [sic]?

A. When you say "reserves," are you talking financial liabilities or collecting cash in advance?

Q. Well, beginning to collect cash in advance and likewise recognizing, for lack of a better way of putting it, the contingent liabilities that would have been associated either with the retirement of those coal-generating facilities or based upon the potential for, you know, groundwater contamination, which, obviously, there was a record in history of it occurring, perhaps not as expansive and pervasive as it was, you know, but it was out there.

I mean, at some point have you to say, if you're aware these problems are out there, they're existing, they're occurring, at what point do you sit back and say, hey, this is something we need to address, we need to be prepared for, and we need to go ahead and either address it, in terms of it being a contingent liability or in terms of creating adequate reserves to address it?

A. I would answer it by -- answer your questions by saying that, on the accounting side, generally speaking, the utilities that I'm aware of did not really establish their asset retirement obligations until those CCR rules came out. Prior to that, it was very difficult to make that estimate. And really it was CCR that triggered that estimate or the recognition of the significant retirement obligations.

In terms of recovering cash in advance, and this is just my personal opinion, I think it's a matter of not having very specific estimates, in terms of what those costs would be and when they would be incurred. And so as a result, they would not include it in depreciation rates to be recovered in advance from customers.

Q. Okay. And I think you said Pricewaterhouse was not the auditor for Duke?

A. That's correct.

Q. I guess the thing I'm trying to it determine -- and this has been something I've wrestled with for quite some time, and that's simply this: If I'm a utility, and I'm out there, and I'm aware that there are potential issues, problems -- or, you know, if you were any other corporation, their management team should be able to -- be able to identify and be aware of things that are, for lack of a better way of putting it, in a more traditional sense, outside of the utility segment, contingent liabilities or issues or problems that are identified which you attach some cost to, and which are actually revealed in your audits and in your financials. Because, you know, it's a duty to disclose it, particularly if it's a publicly traded company.

So the thing I'm trying to wrestle with is, at what point in time kind of the utility -- the utilities that are out there conducting business today really became aware of what they were wrestling with and dealing with to be able to address it, aware would have been reasonably and responsible to do it. And I have -- and I wonder if it was before the adoption CRR [sic]. Maybe CRR, you know -- excuse me, CCR provided a framework, gave them a basis for going out and getting the estimates done and coming up with policies to address it.

But would there have been enough awareness prior to that time to have reasonably taken action? And, I mean, I know that's a bit of a long question and got the acronym, abbreviations a little bit twisted there, but help me out with that.

A. Sure. I would respond by saying that companies have specific footnotes. They talk about environmental exposure, contingent liabilities. Public company filings have what's called an MDNA that talk about matters that the company is looking at in the future that could have an impact on the company. So prior to the issuance of CCR, it took years for those rules to come into effect.

Companies, in general, in the utilities sector were talking about CCR and the potential impact that it would have on the companies. And they had to -- they talk -- in general, they would talk about how that -- those rules were evolving up to them becoming formal and final. At the time they became formal and final is when the accounting entries happened. Prior to that, utilities were talking about the potential impact on utilities across the sector.

But that doesn't necessarily mean that they had very hard numbers that they could point to to say we should start collecting this now. So I'm differentiating ratemaking and disclosures as well as financial accounting.

[Reporter interruption due to sound failure.]

Q. I understand what you're here to testify about. And perhaps some of the other questions that I have in the back of my mind that would help me clarify my thoughts about some of these issues can be addressed by other witnesses that I think are going to be coming up shortly. So thank you.

A. You're welcome.

CHAIR MITCHELL: All right. Let's go back to questions on Commissioners' questions. Let's start with the Public Staff.

MR. GRANTMYRE: Yes. Bill Grantmyre.

EXAMINATION BY MR. GRANTMYRE:

Q. Mr. Riley, you were asked questions by

Commissioner Duffley and Commissioner Hughes, and you were talking about potential write-offs. I think you used the word "billions of dollars." And then there were some examples where it was less than that.

But aren't you aware that, in this case, the difference -- between based on Public Staff Exhibit 79, which is Public Staff Doss/Spanos Rebuttal Cross Examination Exhibit Number 4, that the real differential in total dollars between what the Public Staff says they should recover, which is $262 million, and what Duke Carolinas wants to recover, being $430 million, that's only $168 million differential rather than the billions that you were discussing; would you agree with that?

A. I don't have that -- I don't have that exhibit in front of me here, but I think the billions was a hypothetical.

Q. And also you said if you -- if Duke gets an adverse ruling in this case, they may have to write off some stuff in the future.

Would it only apply to the dollars in this case that we're discussing in this case, the deferral amounts for the last two years?

A. As I mentioned earlier, to the extent that there is a disallowance in this case, the Company would also need to make an assessment as to whether or not there are other disallowances that are now probable as a result of a determination like that in this case.

Q. Well, should Duke Carolinas decide to appeal that, that would indicate that they think that future disallowances are not probable because the Commission erred, and therefore they would not have to do a write-off, would they?

A. I can't testify as to what they think. They would have to go through that thought process as to whether or not it is probable.

Q. Thank you.

CHAIR MITCHELL: All right. Ms. Townsend?

MR. GRANTMYRE: No further questions.

CHAIR MITCHELL: All right. Thank you, Mr. Grantmyre.

Ms. Townsend, anything from the Attorney General's Office? Or Ms. Force.

MS. FORCE: Yes. I have a couple of questions for Mr. Riley.

EXAMINATION BY MS. FORCE:

Q. Mr. Riley, I'm Margaret Force. To follow up on the questions that you were asked by -- well, several Commissioners, but last Commissioner McKissick. You've talked about shareholder dollars being disallowed.

If a commission were to determine that some of the dollars had already been accumulated in the past for the Company, would that be something that you would consider shareholder dollars being spent? Is that a disallowance in that case, or is that just not --

A. I apologize. I'm a little confused on your question. Are you saying that they would have -- if they've recovered monies already from ratepayers?

Q. Well, here, I'll give you a hypothetical. If you have a situation where a company has included in incremented rates to recover -- to put aside some of the cost of dismantling the plants involved, and then, at some point, that situation becomes a legal asset retirement obligation, do you -- when you identify the amount of the obligation, how do you treat the amount that has been accumulated in the past where it was not at that point yet and a legal obligation?

A. So the amount recovered in advance from ratepayers would be accumulated as a regulatory liability. In other words, if those monies were not spent as intended, then it would have to be refunded to ratepayers. So to the extent that the Company has a retirement obligation and it spends money on those retirement activities, then it would relieve the obligation. It would also be relieving that regulatory liability, because it would no longer have to refund those monies to ratepayers.

Q. So for accounting purposes, I think what you're saying is it should already be reflected on the books as a liability because it's been accumulating; is that right?

A. I would agree.

Q. I see. Okay. And could you tell me, if you have a nonregulated entity that -- including a utility that's not regulated that, for instance, has a coal plant that bids into a power exchange, and the rules came out that indicated that the cost of closure of those coal ash impoundments is going to be more than what was previously anticipated, is that something that, for accounting purposes, would be written off?

A. No, you would not write it off. What you would do is recognize that change at the time it happens. And I used the phrase earlier, it's a change in estimate. So you would revise your obligation estimate, record an associated asset retirement cost. So you would add to your asset retirement cost, and then amortize that asset retirement cost over the remaining life of the related asset.

Q. I see. But in terms of how that would be handled, then, since the -- it doesn't have regulated rates, it would be, perhaps, written off because the entity doesn't want to carry that going forward on its books since it's a non-obligation?

A. I think -- I think what you're thinking of, and tell me if I'm wrong, is that Generally Accepted Accounting Principles require companies to evaluate whether or not an asset is impaired. Now, this is an unregulated business, and so there are very specific rules around evaluating assets for impairment. But it would have to be evaluated. The future cash flows that would be generated from that facility undiscounted would be compared to the carrying value of those assets, and to the extent that the assets on the books were greater than the gross cash flows to be recovered from that facility through sales, then you would have an impairment to recognize.

Q. Okay. I appreciate the terminology.

MS. FORCE: Thank you. I don't have any

other questions.

CHAIR MITCHELL: All right. Any other questions from intervenors on Commissioners' questions?

(No response.)

CHAIR MITCHELL: All right. Mr. Heslin?

MR. HESLIN: Yes, just a few, Chair Mitchell.

EXAMINATION BY MR. HESLIN:

Q. This refers to Commissioner Duffley's questions, Mr. Riley, and a little bit to what Mr. Grantmyre tried to walk you through. But in the event in this case, were the Commission to adopt and approve the Public Staff's proposal of equitable sharing, and in doing so, use that as the justification to disallow 50 percent of the coal ash costs in this case for the amounts that are requested in this case, can you explain again what the impact would be on the estimated costs in the future, from an accounting perspective, and how the Company would have to look at that and treat it?

A. So as I tried to state earlier, the Company has to evaluate if there's a disallowances, and if it's probable that there's a disallowance -- and as a result

MR. ROBINSON: Thank you.

COMMISSIONER CLODFELTER: All right. Have we done what we need to do with Mr. Riley?

MR. ROBINSON: I believe we have, sir.

COMMISSIONER CLODFELTER: Okay, great. Are there any cleanup items before the Company closes its case in chief?

MR. ROBINSON: Commissioner Clodfelter, not at this time.

COMMISSIONER CLODFELTER: Okay. Let me say to the parties too, when I just said "close your case in chief," I want to say that we will -- when we complete the proceedings here, we will close the record as to testimony, but the record will remain open as to requests for late-filed exhibits. So anything that is requested as a late-filed exhibit, the record will remain open for those. And so when I tell you you're closing your case, don't think that means you're not going to be putting in your late-filed exhibits. I think we're all clear on that.

All right. We'll move next to the Office of the Attorney General. And let me just ask -- let me ask Ms. Townsend or Ms. Force, I'm not sure which of you, I think the only witness you will be offering is Mr. Hart. But were there any other witnesses for the Attorney General for this separate proceeding who had been previously excused and you need to get their testimony in, or for whom cross examination was waived and you would like to go ahead and get their testimony in?

MS. TOWNSEND: Yes, Commissioner Clodfelter, and Ms. Force will introduce that testimony.

COMMISSIONER CLODFELTER: Great. Ms. Force, you're on.

MS. FORCE: In the consolidated portion of the hearing, we presented the testimony of Richard A. Baudino, and I believe the -- what we said at that time was that we would request that his testimony be entered at the appropriate time. So I assume that you will want me to run through that now.

COMMISSIONER CLODFELTER: Actually I believe his testimony was admitted if I'm -- into evidence in the consolidated proceeding. So it is part of the record in this case because of the consolidation. What I said in the opening was that the testimony of witnesses who testified in the consolidated hearing whose testimony was admitted in that hearing will be copied into the record in this proceeding at the beginning of the record. So Mr. Baudino's testimony is -- has been copied into the record at the beginning of this case.

In other words, what we've got, when you get a transcript for this case, the first thing you'll see in this transcript will be just as if there was no consolidation. You'll see all the testimony of the consolidated witnesses first, and then we'll pick up with the witnesses that we started with yesterday.

MS. FORCE: Okay. That's fine, then. His testimony and exhibits would have been admitted at that point, then, so.

COMMISSIONER CLODFELTER: That is correct.

MS. FORCE: I'll turn it over to Ms. Townsend, then, thank you.

COMMISSIONER CLODFELTER: Very good. Thank you.

(Exhibits RAB-1 through RAB-7, and Supplemental Exhibits RAB-1 through

RAB-4 were admitted into evidence.)

(Whereupon, the prefiled direct and supplemental testimony of Richard A. Baudino were copied into the record as if given orally from the stand.)

I. QUALIFICATIONS AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Richard A. Baudino. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A. I am a consultant with Kennedy and Associates.

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received my Master of Arts degree with a major in Economics and a minor in Statistics from New Mexico State University in 1982. I also received my Bachelor of Arts Degree with majors in Economics and English from New Mexico State in 1979.

I began my professional career with the New Mexico Public Service Commission Staff in October 1982 and was employed there as a Utility Economist. During my employment with the Staff, my responsibilities included the analysis of a broad range of issues in the ratemaking field. Areas in which I testified included cost of service, rate of return, rate design, revenue requirements, analysis of sale/leasebacks of generating plants, utility finance issues, and generating plant phase-ins.

In October 1989, I joined the utility consulting firm of Kennedy and Associates as a Senior Consultant where my duties and responsibilities covered substantially the same areas as those during my tenure with the New Mexico Public Service Commission Staff. I became Manager in July 1992 and was named Director of Consulting in January 1995. Currently, I am a consultant with Kennedy and Associates.

Attachment A summarizes my expert testimony experience.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the North Carolina Attorney General's Office ("AGO").

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my Direct Testimony is to address the allowed return on equity, capital structure, and overall rate of return on rate base for the regulated electric operations of Duke Energy Progress, Inc. ("Duke Progress", or "Company"). I will also respond to the Direct Testimonies of Mr. Robert Hevert and Mr. Karl Newlin, witnesses for Duke Progress.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. My conclusions and recommendations are as follows.

Based on financial market conditions through February 2020, I recommend that the North Carolina Utilities Commission ("NCUC" or "Commission") adopt a 9.0% return on equity for Duke Progress in this proceeding. My recommendation is based primarily on the results of a Discounted Cash Flow ("DCF") model analysis and is conservatively high given the results. My DCF analysis incorporates my standard approach to estimating the investor required return on equity and utilizes the proxy group of 19 companies used by Duke Progress witness Hevert.

My cost of equity analysis also includes Capital Asset Pricing Model ("CAPM") analyses for additional information to further inform my recommendation to the Commission. I did not incorporate the results of the CAPM in my recommendation given the low cost of equity results being produced by this model at this time. Nonetheless, the CAPM results confirm the fact that the required ROE for regulated electric utilities continues to be low given the low interest rate environment that has prevailed in the economy for the last 10 or so years.

Finally, I also reviewed recent Commission-allowed ROEs presented by Mr. Hevert. Although I do not recommend that the Commission base its allowed ROE on the actions of other regulatory commissions, this review helped inform my recommended ROE of 9.0%.

I also recommend that the Commission reject Duke Progress' requested 53% equity ratio. The Company's requested equity ratio is higher than the average common equity ratio of the proxy group and would result in excessive rates to Duke Progress' North Carolina customers. Instead, I recommend that the Commission approve a 51.5% common equity ratio for Duke Progress, which matches my recommendation for Duke Energy Carolinas, Inc. in Docket No. E-7, SUB 1214. I also recommend that the Commission accept Duke Progress' requested cost of debt.

In Section IV of my testimony, I review Mr. Hevert's analysis of economic conditions in North Carolina and address his conclusion that these conditions support his recommended 10.5% ROE in this case. I disagree with Mr. Hevert's conclusion and explain why economic conditions in the state do not support his 10.5% ROE, but do support my recommended 9.0% ROE and capital structure.

In Section V, I respond to the testimony and ROE recommendation of the Company's witness Mr. Hevert. I will demonstrate that his recommended ROE of 10.5% substantially overstates the current investor required return for a lower risk regulated electric company like Duke Progress. Although Duke Progress seeks an allowed ROE of 10.3%, this slightly lower ROE fails to reflect recent financial market conditions and fails to mitigate rate impacts on ratepayers. Today's financial environment of low interest rates has been deliberately and methodically supported by Federal Reserve policy actions since 2009. The Fed's further lowering of short-term interest rates three times in 2019 as well as the Fed's further lowering of short-term rates in 2020 support future expectations of lower interest rates through 2020. Moreover, Mr. Hevert ignored a significant portion of his ROE analyses from the DCF and CAPM models that showed much lower results than his recommended ROE range of 10.0% – 11.0% and his 10.5% recommended ROE.

Q. DO YOU HAVE ANY ADDITIONAL TESTIMONY REGARDING CURRENT FINANCIAL MARKET CONDITIONS THAT YOU WOULD LIKE TO PRESENT TO THE COMMISSION AT THIS TIME?

A. Yes. Since the beginning of March 2020, financial markets experienced unprecedented volatility, with steep and sharp declines in the stock market, including regulated utilities. The yield on the 30-Year Treasury bond declined from 1.97% in February to 0.99% on March 9, then increased to 1.63% on March 17. Alternatively, the yield on the average public utility bond increased dramatically, rising from 3.14% in February to 4.24% on March 18, according to Moody's Credit Trends. . On April 6, 2020 the average utility bond yield was 3.73%. As of the preparation of my Direct Testimony in this proceeding, I have concluded that it would not be prudent for me to estimate the impact of these changed conditions on my ROE recommendation for Duke Progress given that these changes and associated volatility in financial markets have occurred over just the last three to four weeks and are ongoing. However, I also believe it is important for the North Carolina Utilities Commission to have as much updated information as possible on the drastically changed conditions in financial markets subject to the constraints of the current procedural schedule. Therefore, I reserve the right to update my testimony and recommendations to the Commission later in this proceeding and before the scheduled hearing in this docket.

II. <u>FUNDAMENTALS OF SETTING THE ALLOWED RETURN ON EQUITY</u>

Q. WHAT ARE THE MAIN GUIDELINES TO WHICH YOU ADHERE IN ESTIMATING THE COST OF EQUITY FOR A FIRM?

A. Generally speaking, the estimated cost of equity should be comparable to the returns of other firms with similar risk structures and should be sufficient for the firm to attract capital. These are the basic standards set out by the United States Supreme Court in *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) and *Bluefield W.W. & Improv. Co. v. Public Service Comm'n*, 262 U.S. 679 (1922).

From an economist's perspective, the notion of "opportunity cost" plays a vital role in estimating the return on equity. One measures the opportunity cost of an investment equal to what one would have obtained in the next best alternative. For example, let us suppose that an investor decides to purchase the stock of a publicly traded electric utility. That investor made the decision based on the expectation of dividend payments and perhaps some appreciation in the stock's value over time; however, that investor's opportunity cost is measured by what she or he could have invested in as the next best alternative. That alternative could have been another utility stock, a utility bond, a mutual fund, a money market fund, or any other number of investment vehicles.

The key determinant in deciding whether to invest, however, is based on comparative levels of risk. Our hypothetical investor would not invest in a particular electric company stock if it offered a return lower than other investments of similar risk. The opportunity cost simply would not justify such an investment. Thus, the task for the rate of return analyst is to estimate a return that is equal to the return being offered by other risk-comparable firms.

Q. DOES THE LEVEL OF INTEREST RATES AFFECT THE ALLOWED COST OF EQUITY, OR ROE, FOR REGULATED UTILITIES?

A. Yes. The common stock of regulated utilities is considered to be interest rate sensitive. This means that the cost of equity for regulated utilities tends to rise and fall with changes in interest rates. For example, as interest rates rise, the cost of equity will also rise and vice versa when interest rates fall. This relationship is due in large part to the capital intensive nature of the utility industry, which relies heavily on both debt and equity to finance its regulated investments.

Q. DESCRIBE THE TREND IN INTEREST RATES OVER THE LAST 10 OR SO YEARS.

A. Since 2007 and 2008, the overall trend in interest rates in the U.S. and the world economy has been lower. This trend was precipitated by the 2007 financial crisis and severe recession that followed in December 2007. In response to this economic crisis, the Federal Reserve ("Fed") undertook an unprecedented series of steps to stabilize the economy, ease credit conditions, and lower unemployment and interest rates. These steps are commonly known as Quantitative Easing ("QE") and were implemented in three distinct stages: QE1, QE2, and QE3. The Fed's stated purpose of QE was "to support the liquidity of financial institutions and foster improved conditions in financial markets."[1]

Q. MR. BAUDINO, BEFORE YOU CONTINUE, PLEASE PROVIDE A BRIEF EXPLANATION OF HOW THE FED USES INTEREST RATES TO IMPROVE CONDITIONS IN THE FINANCIAL MARKETS.

[1] https://www.federalreserve.gov/monetarypolicy/bst_crisisresponse.htm

A. Generally, the Fed uses monetary policy to implement certain economic goals. The Fed explained its monetary policy as follows:

> Monetary policy in the United States comprises the Federal Reserve's actions and communications to promote maximum employment, stable prices, and moderate long-term interest rates--the three economic goals the Congress has instructed the Federal Reserve to pursue.
>
> The Federal Reserve conducts the nation's monetary policy by managing the level of short-term interest rates and influencing the overall availability and cost of credit in the economy.[2]

One of the Fed's primary tools for conducting monetary policy is setting the federal funds rate. The federal funds rate is the interest rate set by the Fed that banks and credit unions charge each other for overnight loans of reserve balances. Traditionally the federal funds rate directly influences short-term interest rates, such as the Treasury bill rate and interest rates on savings and checking accounts. The federal funds rate has a more indirect effect on long-term interest rates, such as the 30-Year Treasury bond and private and corporate long-term debt. Long-term interest rates are set more by market forces that influence the supply and demand of loanable funds.

Q. WHAT HAS BEEN THE TREND OF LONG-TERM INTEREST RATES SINCE THE 2007 FINANCIAL CRISIS?

A. Figure 1 below presents a graph that tracks the 30-Year Treasury Bond yield and the Mergent average utility bond yield. The time period covered is January 2008 through January 2020.

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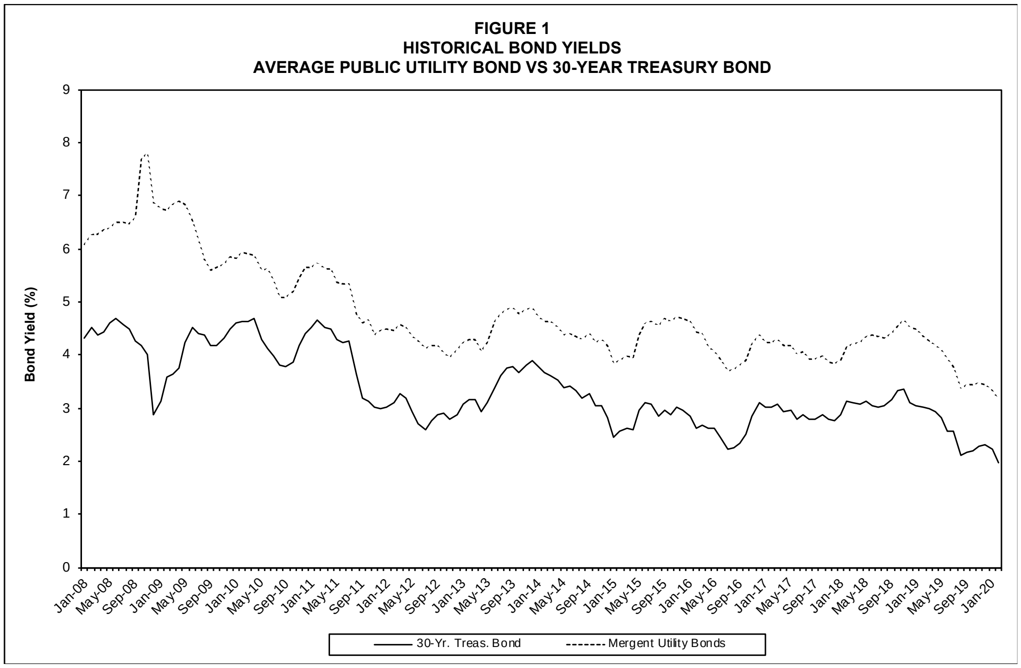
[2] https://www.federalreserve.gov/monetarypolicy.htm



The Fed's QE program and federal funds rate cuts during this period were effective in lowering the long-term cost of borrowing in the United States. We can see from the graph in Figure 1 that since 2008, the trend in long-term bond yields has been consistently lower. In January 2008, the yield on the 30-Year Treasury Bond was 4.33% and the yield on the average public utility bond was 6.08%. *As of February 2020, the 30-Year Treasury yield was 1.97% and the average utility bond yield was 3.16%*. However, as I mentioned earlier in my testimony, average utility bond yields increased recently in March despite declines in long-term Treasury Bonds. I will continue to monitor changing market conditions and provide updates to the Commission before the evidentiary hearings begin.

Q. PLEASE SUMMARIZE RECENT FED ACTIONS WITH RESPECT TO MONETARY POLICY.

A. In December 2015, the Fed began to raise its target range for the federal funds rate, increasing it to 1/4% to 1/2% from 0% to 1/4%. Since that time, the Fed increased the federal funds rate several more times, with the most recent increase announced on December 19, 2018 resulting in a federal funds rate range of 2.25% - 2.50%.

In 2019, however, the Fed reversed course and lowered the federal funds rate three times. On March 3 and 15, 2020, the Fed again lowered the federal funds rate in response to mounting concerns associated with the spread of the coronavirus worldwide. On March 15, the Fed issued a press release that stated the following:

> Consistent with its statutory mandate, the Committee seeks to foster maximum employment and price stability. The effects of the coronavirus will weigh on economic activity in the near term and pose risks to the economic outlook. In light of these developments, the Committee decided to lower the target range for the federal funds rate to 0 to 1/4 percent. The Committee expects to maintain this target range until it is confident that the economy has weathered recent events and is on track to achieve its maximum employment and price stability goals. This action will help support economic activity, strong labor market conditions, and inflation returning to the Committee's symmetric 2 percent objective.
>
> The Committee will continue to monitor the implications of incoming information for the economic outlook, including information related to public health, as well as global developments and muted inflation pressures, and will use its tools and act as appropriate to support the economy. In determining the timing and size of future adjustments to the stance of monetary policy, the Committee will assess realized and expected economic conditions relative to its maximum employment objective and its symmetric 2 percent inflation objective. This assessment will take into account a wide range of information, including measures of labor market conditions, indicators of inflation pressures and inflation expectations, and readings on financial and international developments.

> The Federal Reserve is prepared to use its full range of tools to support the flow of credit to households and businesses and thereby promote its maximum employment and price stability goals. To support the smooth functioning of markets for Treasury securities and agency mortgage-backed securities that are central to the flow of credit to households and businesses, over coming months the Committee will increase its holdings of Treasury securities by at least $500 billion and its holdings of agency mortgage-backed securities by at least $200 billion. The Committee will also reinvest all principal payments from the Federal Reserve's holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities. In addition, the Open Market Desk has recently expanded its overnight and term repurchase agreement operations. The Committee will continue to closely monitor market conditions and is prepared to adjust its plans as appropriate.

The Federal Reserve also announced expanded actions to support credit and financial markets since this statement was issued. The Board of Governors of the Federal Reserve system established a new resource on its web site that contains the Fed's ongoing response to the Covid-19 pandemic: https://www.federalreserve.gov/covid-19.htm.

Q. WHY IS IT IMPORTANT TO UNDERSTAND THE FED'S ACTIONS SINCE 2008 AND THE EFFECT ON THE CURRENT COST OF CAPITAL IN THE ECONOMY GENERALLY AND FOR REGULATED UTILITIES SPECIFICALLY?

A. The Fed's monetary policy actions since 2008 were deliberately undertaken to lower interest rates and support economic recovery. The U.S. economy is still in a low interest rate environment. This environment has affected the common stocks of regulated utilities, which, as I mentioned earlier, are interest rate sensitive. Lower interest rates support lower required ROEs for regulated utilities.

Q. ARE CURRENT INTEREST RATES INDICATIVE OF INVESTOR EXPECTATIONS REGARDING THE FUTURE DIRECTION OF INTEREST RATES?

A. Yes. Securities markets are efficient and most likely reflect investors' expectations about future interest rates. As Dr. Morin pointed out in *New Regulatory Finance:*

> A considerable body of empirical evidence indicates that U.S. capital markets are efficient with respect to a broad set of information, including historical and publicly available information.[3]

Dr. Morin also noted the following:

> There is extensive literature concerning the prediction of interest rates. From this evidence, it appears that the no-change model of interest rates frequently provides the most accurate forecasts of future interest rates while at other times, the experts are more accurate. Naïve extrapolations of current interest rates frequently outperform published forecasts. The literature suggests that on balance, the bond market is very efficient in that it is difficult to consistently forecast interest rates with greater accuracy than a no-change model. The latter model provides similar, and in some cases, superior accuracy than professional forecasts.[4]

It is important to realize that investor expectations of changes in future interest rates, if any, are likely already embodied in current securities prices, which include debt securities and stock prices. Moreover, the current low interest rate environment still favors lower risk regulated utilities.

Q. YOU MENTIONED THAT THE REQUIRED COST OF EQUITY FOR REGULATED UTILITIES TENDS TO FOLLOW THE DIRECTION OF

[3] Morin, Roger A., *New Regulatory Finance,* Public Utilities Reports, Inc. (2006) at 279.
[4] *Id*. at 172.

INTEREST RATES. COULD YOU ILLUSTRATE THIS RELATIONSHIP FOR THE COMMISSION?

A. Yes. Table 1 below presents data from Mr. Hevert's Exhibit RBH-5 and presents the average yearly yield on the 30-year Treasury Bond and the yearly average allowed ROE for electric companies from 2000 through August 12, 2019. Table 1 shows that as the long-term Treasury Bond yield has fallen since 2000, allowed ROEs for electric utilities followed suit, although the decline in ROEs has been less than that for the 30-year Treasury Bond. The Premium column in Table 1 shows the difference between allowed ROEs and the 30-Year Treasury yield. In 2007, for example, the premium of allowed ROEs over Treasury yields was 5.45%. The premium has grown significantly since 2007, rising to almost 7.0% in 2012 and 2016 and falling to 6.48% through August 2019. The purpose of Table 1 is to demonstrate the interest rate sensitivity of regulated utility ROEs to the general level of interest rates, not to recommend that the Commission follow this relationship or rely on the commission-allowed ROEs from other states. I shall demonstrate later in my testimony that current market data shows that the investor required ROEs for regulated electric utilities are lower than recent Commission allowed ROEs.

Table 1
Allowed ROEs and
30-Year Treasury Yields

Year	Allowed ROE	30-Year T-Bond	Premium
2000	11.58%	6.07%	5.51%
2001	11.07%	5.59%	5.48%
2002	11.21%	5.42%	5.79%
2003	10.96%	4.94%	6.03%
2004	10.81%	5.06%	5.75%
2005	10.51%	4.71%	5.81%
2006	10.34%	4.83%	5.52%
2007	10.31%	4.87%	5.45%
2008	10.37%	4.54%	5.83%
2009	10.52%	4.02%	6.50%
2010	10.29%	4.33%	5.96%
2011	10.19%	4.13%	6.06%
2012	10.01%	3.03%	6.98%
2013	9.81%	3.21%	6.60%
2014	9.75%	3.51%	6.24%
2015	9.60%	2.90%	6.70%
2016	9.60%	2.62%	6.97%
2017	9.68%	2.82%	6.86%
2018	9.56%	2.99%	6.57%
2019	9.57%	3.10%	6.48%

Source: Exhibit No. RBH-5

Q. HOW DOES THE INVESTMENT COMMUNITY REGARD THE REGULATED ELECTRIC UTILITY INDUSTRY AS A WHOLE?

A. There are two excerpts from Value Line Investment Survey reports that I would like to share with the Commission regarding the electric utility industry. This initial excerpt comes from Value Line's February 14, 2020 report on the Electric Utility (East) and was published before the recent extreme financial market volatility in March 2020:

> Most electric utility stocks performed well in 2019. Interest-rate cuts by the Federal Reserve and heightened interest in dividend-paying equities were the key factors. The median total return among a group of 40 stocks compiled by the Edison Electric Institute (a group representing investor-owned utilities) was 25.1%. Southern Company led the way with a whopping 51.3% total return. NextEra Energy posted a 42.6% total return. These stocks continued to fare well five weeks into the new year. In 2019, Eversource, FirstEnergy, and PPL Corporation

> recorded total returns of more than 30%. By contrast, Exelon's total return was just 4.2%; the reasons for this can be read in our report on the stock.
>
> Following the stellar performance of most utility issues in 2019, the valuation of this group remains high. The average dividend yield is just 3.0%. This is above the median for dividend-paying stocks, but is low by historical standards.

The second excerpt comes from Value Line's report on the Electric Utility (Central) industry and is dated March 13, 2020.

> Electric utility stocks are usually among the most stable of equities (note their high Price Stability Indexes, in most cases), but they have exhibited more volatility than usual this year. Some equities still have high valuations. The recent price of Ameren is above our 2023-2025 Target Price Range, and most recent quotations are well within this range. On the other hand, the price of CenterPoint Energy stock has fallen to the point where the dividend yield is over 5% (roughly two percentage points above the utility average). The average yield for electric utility stocks fell below 3% just before the market decline in late February, but is now 3.25%. Investors should be aware that a high dividend yield usually arises from some drawbacks. These can include subpar dividend growth potential, regulatory risk, or difficult market conditions for nonregulated operations.

Despite recent financial market volatility in March, my position regarding the current low interest rate environment is consistent with Value Line's report on the electric utility industry. Lower interest rates will mean lower allowed ROEs and this is a positive development for utility ratepayers. Further, lower interest rates translate into lower debt costs and a lower cost of capital applied to the utility's rate base. Again, this is a positive trend for ratepayers' cost of electricity.

Q. THE EDISON ELECTRIC INSTITUTE ("EEI") PUBLISHES QUARTERLY REVIEWS OF THE INVESTOR-OWNED ELECTRIC

UTILITY INDUSTRY. PLEASE SUMMARIZE EEI'S FINDINGS WITH RESPECT TO CREDIT RATINGS, RISKS, AND VALUATIONS FOR THE ELECTRIC UTILITY INDUSTRY.

A. EEI's 4th Quarter 2019 summary of the Standard and Poor's Utility Credit Ratings showed the following:

- The industry average credit rating was BBB+.
- 58% of the 45 utilities followed by EEI had credit ratings of BBB/BBB+.
- 27% had a credit rating of A-.

EEI's analysis showed that the investor-owned electric utility industry had strong and stable credit metrics through the 4th Quarter of 2019.

EEI's *Q4 2019 Financial Update*, pages 5 and 6, noted the following regarding electric utility common stock valuations:

> "At year-end, Wall Street analysts generally viewed utility stock valuations as high when measured by price/earnings (PE) ratios relative to the S&P 500 and to history. One reason for high PEs is the very low level of interest rates both in the U.S. and overseas. The U.S. 10-year Treasury yield was about 6% in the late 1990s, more than triple today's level, while bond markets in Europe and Japan sport widespread negative yields that drive global investors into relatively safe positive-yielding investments like utilities. *Another reason is the strong fundamentals that underpin prospects for total returns in excess of 8% (5% from earnings growth and 3% from the dividend). While PEs seem high, utilities may offer enough value to lift multiples higher still if global economic growth turns down and interest rates fall to new lows.* (italics added)

EEI's publication also noted the following with respect to interest rates:

> "*A sharp rise in interest rates is widely seen as the biggest macro threat facing utility investors. Although that has been said for years and interest rates just seem to fall. Inflation held near 2%*

> *throughout 2018 even as the economy roared and didn't move in 2019 either. The main risk to the very long-lived economic expansion seems to be weakness rather than red-hot growth*.
>
> A second, less discussed risk is pushback on rate increases needed to fund capex programs. Stable fuel costs and low interest rates have kept bill pressures muted. Industry analysts expect that trend will continue. *But if the economy enters recession and consumer incomes fall, managing regulatory risk and financing needed capex through customer rates may become more challenging than it has been in recent years*. (emphasis added)

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THE EEI REPORT.

A. I underscore to the Commission EEI's statements regarding (1) prospects for total returns in excess of 8%, and (2) the stability of the current low interest rate environment despite years of predictions of higher interest rates. These statements tend to support my recommended ROE for Duke Progress of 9.0% and that the Commission should reject Mr. Hevert's excessive recommended ROE of 10.5%. The EEI report also shows that the strong credit ratings for regulated electric companies are fully consistent with lower ROEs and a lower cost of debt. In my view, these points support my recommended cost of equity for Duke Progress of 9.0% as being reasonably consistent with investor expectations and current market conditions. Please note that in Section III of my Direct Testimony, I will have a more detailed discussion of recent stock market volatility and its impact on my ROE recommendation for Duke Progress.

Q. WHAT ARE THE CURRENT CREDIT RATINGS FOR DUKE ENERGY PROGRESS?

A. Moody's long-term issuer rating for Duke is A2. Within Moody's A rating category, A1 is the highest rating and A3 is the lowest. Standard and Poor's ("S&P") credit rating is A-, which is the lowest rating in S&P's A category (A+ being the highest). The ratings outlook from both Moody's and S&P is stable. On November 20, 2019 S&P affirmed the credit ratings of Duke Energy and its operating utility subsidiaries, including Duke Progress, and revised its ratings outlook to stable from negative.

S&P's February 28, 2020 credit report for Duke Progress noted the following key credit strengths for the Company[5]:

- Lower-risk vertically integrated utility with regulatory diversity in North and South Carolina.
- The 2019 settlement reached between DEP and the North Carolina Department of Environmental Quality (NCDEQ) reduces legal uncertainty associated with the company's ash pond closure strategy.
- DEP provides electric service to approximately 1.6 million customers, which supports cash flow stability.
- DEP has generally managed regulatory risk effectively, primarily in North Carolina which accounts for about 85% of the company's retail rate base.

Duke Progress' key credit according to S&P are:

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[5] The S&P report was provided by Duke Progress in response to AGO Data Request 6-1.

- DEP's service territory is prone to hurricanes and severe storms, a risk that is partially offset by recent passage of a storm securitization legislation that permits recovery for certain storm recovery costs.
- There is potential for regulatory lag to delay the timeliness of the company's cost recovery, and future cost recovery for coal-ash costs per the terms of the NCDEQ settlement has not yet been determined.
- The revised U.S. tax code is expected to weaken the Company's cash flow metrics beginning in 2020.
- Environmental and operating risks associated with the Company's coal-fired and nuclear power generation assets.

S&P's report explained that Duke Progress' business risk is "excellent" based on the Company's "lower-risk electric utility operations that benefit from a generally constructive regulatory framework, track record of reliable electric service, and large customer base." Financial risk is considered "significant".

Q. DID DUKE ENERGY, THE HOLDING COMPANY FOR DUKE PROGRESS, PROVIDE INFORMATION TO ITS INVESTORS THAT IS RELEVANT TO THE COMMISSION'S EVALUATION OF THE ALLOWED RATE OF RETURN FOR THE COMPANY?

A. Yes. Please refer to Exhibit RAB-1, which contains excerpts from Duke Energy's *Earnings Review & Business Update, Fourth Quarter 2019* dated February 13, 2020. I obtained this presentation from Duke Energy's web site.

Page 2 of Exhibit RAB-1 states that Duke Energy's "[r]apidly expanding infrastructure needs driven by strong fundamental growth." Duke Energy showed a 12% increase in its 5-year capital plan fueled by "low-risk investments."

Page 3 of Exhibit RAB-1 contains Duke Energy's analysis of how the $6 billion increase is its capital plan "drives significant earnings base growth," which includes a $4 billion increase in the Carolinas.

Page 4 of Exhibit RAB-1 summarizes Duke Energy's presentation of its "balance sheet strength and equity financing plan." Duke Energy stated that it is committed to "strong credit quality" that includes credit ratings of BBB+/Baa1 with a stable outlook. Duke Energy also mentioned that it was not expected to be a significant taxpayer until the 2027 time frame.

Page 5 of Exhibit RAB-1 shows Duke Energy's presentation of its "attractive risk-adjusted total shareholder return" of 8% – 10%. This total return consists of a dividend yield of 3.9% and a growth rate of 4% – 6%. I note that my recommended ROE for Duke Progress of 9.0% falls in the middle of this range. Mr. Hevert's recommended ROE of 10.5% is well above the total shareholder return range cited by Duke Energy in this presentation.

Q. WHAT IS YOUR CONCLUSION WITH RESPECT TO THE OVERALL RISKINESS OF DUKE PROGRESS?

A. Both Moody's and S&P's recent credit rating reports on Duke Progress indicate that although the Company is facing risks associated with the ultimate disposition of coal ash costs as well as elevated construction spending, those risks are tempered by the Company's low risk regulated business and its low operating risk. Taken together, Duke Progress has credit ratings that are slightly above average compared to the average S&P credit rating of BBB+ for the electric utilities covered by the aforementioned EEI publication.

With respect to the return on equity in this case, Duke Progress' credit standing indicates that its allowed ROE should be based on the average results of the proxy group that Mr. Hevert and I use in this case. There is no basis for the Company's allowed ROE to be higher than the proxy group results given the Company's above average credit rating.

III. DETERMINATION OF RETURN ON EQUITY

Q. PLEASE DESCRIBE THE METHODS YOU EMPLOYED IN ESTIMATING YOUR RECOMMENDED RETURN ON EQUITY FOR DUKE PROGRESS.

A. I employed a Discounted Cash Flow ("DCF") analysis using a proxy group of 19 regulated electric utilities as selected by Mr. Hevert. In my opinion, they form a reasonable basis for estimating the investor required return on equity for Duke Progress. I also employed Capital Asset Pricing Model ("CAPM") analyses using both historical and forward-looking data. Although I primarily relied on the DCF results for my recommended 9.0% ROE for the Company, the results from the CAPM tend to support the reasonableness of my recommendation.

Q. DESCRIBE THE PROXY GROUP YOU EMPLOYED TO ESTIMATE THE COST OF EQUITY FOR DUKE PROGRESS.

A. In this case, I chose to use the same proxy group that Mr. Hevert used in his ROE analyses. Mr. Hevert discussed his approach to developing his recommended proxy group on pages 23 through 24 of his Direct Testimony. Mr. Hevert's selection criteria are generally reasonable and include regulated electric utilities that have investment grade credit ratings from S&P. Using the same proxy group as Mr. Hevert also has the advantage of eliminating a source of disagreement between our respective ROE analyses and furnishes the Commission with a consistent group of companies to compare and evaluate our ROE results and recommendations.

Discounted Cash Flow ("DCF") Model

Q. PLEASE DESCRIBE THE BASIC DCF APPROACH.

A. The basic DCF approach is rooted in valuation theory. It is based on the premise that the value of a financial asset is determined by its ability to generate future net cash flows. In the case of a common stock, those future cash flows generally take the form of dividends and appreciation in stock price. The value of the stock to investors is the discounted present value of future cash flows. The general equation then is:

$$V = \frac{R}{(1+r)} + \frac{R}{(1+r)^2} + \frac{R}{(1+r)^3} + \cdots \frac{R}{(1+r)^n}$$

Where: *V = asset value*
R = yearly cash flows
r = discount rate

This is no different from determining the value of any asset from an economic point of view; however, the commonly employed DCF model makes certain simplifying assumptions. One is that the stream of income from the equity share is assumed to be perpetual; that is, there is no salvage or residual value at the end of some maturity date (as is the case with a bond). Another important assumption is that financial markets are reasonably efficient; that is, they correctly evaluate the cash flows relative to the appropriate discount rate, thus rendering the stock price efficient relative to other alternatives. Finally, the model I typically employ also assumes a constant growth rate in dividends. The fundamental relationship employed in the DCF method is described by the formula:

$$k = {}^{D_1}/_{P_0} + g$$

Where: D_1 *= the next period dividend*
P_0 *= current stock price*
g *= expected growth rate*
k *= investor-required return*

Embodied in this formula, it is assumed that "k" reflects the investors' expected return. Use of the DCF method to determine an investor-required return is complicated by the need to express investors' expectations relative to dividends, earnings, and book value over an infinite time horizon. Financial theory suggests that stockholders purchase common stock on the assumption that there will be some change in the rate of dividend payments over time. We assume that the rate of growth in dividends is constant over the assumed time horizon, but the model could easily handle varying growth rates if we knew what they were. Finally, the relevant time frame is prospective rather than retrospective.

Q. WHAT WAS YOUR FIRST STEP IN DETERMINING THE DCF RETURN ON EQUITY FOR THE PROXY GROUP?

A. I first determined the current dividend yield, D_1/P_0, from the basic equation. My general practice is to use six months as the most reasonable period over which to estimate the dividend yield. The six-month period I used covered the months from September 2019 through February 2020. I obtained historical prices and dividends from Yahoo! Finance. The annualized dividend divided by the average monthly price represents the average dividend yield for each month in the period.

The resulting average dividend yield for the proxy group is 2.88%. These calculations are shown in Exhibit RAB-2. This exhibit also presents monthly dividend yields for the proxy group on page 4. The monthly yields do not vary significantly, ranging from 2.84% to 2.94%. In my opinion, the six-month yield of 2.88% is a reasonable estimate for the proxy group.

Q. HAVING ESTABLISHED THE AVERAGE DIVIDEND YIELD, HOW DID YOU DETERMINE THE INVESTORS' EXPECTED GROWTH RATE FOR THE PROXY GROUP?

A. The investors' expected growth rate, in theory, correctly forecasts the constant rate of growth in dividends. The dividend growth rate is a function of earnings growth and the payout ratio, neither of which is known precisely for the future. We refer to a perpetual growth rate since the DCF model has no cut-off point. We must estimate the investors' expected growth rate because there is no way to know with absolute certainty what investors expect the growth rate to be in the short term, much less in perpetuity.

For my analysis in this proceeding, I used three major sources of analysts' forecasts for growth. These sources are The Value Line Investment Survey, Zacks, and Yahoo! Finance.

Q. PLEASE BRIEFLY DESCRIBE VALUE LINE, ZACKS, AND YAHOO! FINANCE.

A. The Value Line Investment Survey is a widely used and respected source of investor information that covers approximately 1,700 companies in its Standard Edition and several thousand in its Plus Edition. It provides both historical and forecasted information on a number of important data elements. Value Line neither participates in financial markets as a broker nor works for the utility industry in any capacity of which I am aware.

Zacks gathers opinions from a variety of analysts on earnings growth forecasts for numerous firms including regulated electric utilities. The estimates of the analysts responding are combined to produce consensus average estimates of earnings growth. I obtained Zacks' earnings growth forecasts from its web site.

Like Zacks, Yahoo! Finance also compiles and reports consensus analysts' forecasts of earnings growth. I obtained these forecasts from the Yahoo! Finance web site.

Q. WHY DID YOU RELY ON ANALYSTS' FORECASTS IN YOUR ANALYSIS?

A. Return on equity analysis is a forward-looking process. Five-year or ten-year historical growth rates may not accurately represent investor expectations for future dividend and earnings growth. Analysts' forecasts for earnings and dividend growth provide better proxies for the expected growth component in the DCF model than historical growth rates. Analysts' forecasts are also widely available to investors and one can reasonably assume that they influence investor expectations.

Q. PLEASE EXPLAIN HOW YOU USED ANALYSTS' DIVIDEND AND EARNINGS GROWTH FORECASTS IN YOUR CONSTANT GROWTH DCF ANALYSIS.

A. Columns (1) through (4) of Exhibit RAB-3 shows the forecasted dividend and earnings growth rates from Value Line and the earnings growth forecasts from Zacks and Yahoo! Finance for the companies in the proxy group. It is important to include dividend growth forecasts in the DCF model since the model calls for forecasted cash flows and Value Line is the only source of which I am aware that forecasts dividend growth.

Please note that Zacks' earnings growth forecasts were not available for ALLETE and Otter Tail, so I substituted the Yahoo! Finance earnings growth rates for those two companies. I did this because Yahoo! Finance's growth rates are consensus analysts' forecasts and, as such, form a reasonable proxy for the Zacks analysts' estimates.

Q. HOW DID YOU PROCEED TO DETERMINE THE DCF RETURN ON EQUITY FOR THE PROXY GROUP?

A. To estimate the expected dividend yield (D_1), the current dividend yield must be moved forward in time to account for dividend increases over the next twelve months. I estimated the expected dividend yield by multiplying the current dividend yield by one plus one-half the expected growth rate.

Exhibit RAB-3 presents my standard method of calculating dividend yields, growth rates, and return on equity for the proxy group. The DCF Return on Equity Calculation section shows the application of each of four growth rates I used in my analysis to the current group dividend yield of 2.88% to calculate the expected dividend yield. I then added the expected growth rates to the expected dividend yield. My DCF return on equity was calculated using two different methods. Method 1 uses the Average Growth Rates shown in the upper section of Exhibit RAB-3 and Method 2 utilizes the median growth rates shown in that section.

Q. WHAT ARE THE RESULTS OF YOUR CONSTANT GROWTH DCF MODEL?

A. The results for Method 1 range from 8.46% to 8.77% and the results for Method 2 range from 8.21% to 9.02%. The average results for Methods 1 and 2 are 8.60% and 8.67%, respectively, for the proxy group.

Capital Asset Pricing Model

Q. BRIEFLY SUMMARIZE THE CAPITAL ASSET PRICING MODEL ("CAPM") APPROACH.

A. The theory underlying the CAPM approach is that investors, through diversified portfolios, may combine assets to minimize the total risk of the portfolio. Diversification allows investors to diversify away all risks specific to a particular company and be left only with market risk that affects all companies.

Thus, the CAPM theory identifies two types of risks for a security: company-specific risk and market risk. Company-specific risk includes such events as strikes, management errors, marketing failures, lawsuits, and other events that are unique to a particular firm. Market risk includes inflation, business cycles, war, variations in interest rates, and changes in consumer confidence. Market risk tends to affect all stocks and cannot be diversified away. The idea behind the CAPM is that diversified investors are rewarded with returns based on market risk.

Within the CAPM framework, the expected return on a security is equal to the risk-free rate of return plus a risk premium that is proportional to the security's market, or non-diversifiable, risk. Beta is the factor that reflects the inherent market risk of a security and measures the volatility of a particular security relative to the overall market for securities. For example, a stock with a beta of 1.0 indicates that if the market rises by 15%, that stock will also rise by 15%. This stock moves in tandem with movements in the overall market. Stocks with a beta of 0.5 will only rise or fall 50% as much as the overall market. So with an increase in the market of 15%, this stock will only rise 7.5%. Stocks with betas greater than 1.0 will rise and fall more than the overall market. Thus, beta is the measure of the relative risk of individual securities vis-à-vis the market.

Based on the foregoing discussion, the equation for determining the return for a security in the CAPM framework is:

$$K = Rf + \beta(MRP)$$

Where: K = *Required Return on equity*
Rf = *Risk-free rate*
MRP = *Market risk premium*
β = *Beta*

This equation tells us about the risk/return relationship posited by the CAPM. Investors are risk averse and will only accept higher risk if they expect to receive higher returns. These returns can be determined in relation to a stock's beta and the market risk premium. The general level of risk aversion in the economy determines the market risk premium. If the risk-free rate of return is 3.0% and the required return on the total market is 15%, then the risk premium is 12%. Any stock's risk premium can be determined by multiplying its beta by the market risk premium. Its total return may then be estimated by adding the risk-free rate to that risk premium. Stocks with betas greater than 1.0 are considered riskier than the overall market and will have higher required returns. Conversely, stocks with betas less than 1.0 will have required returns lower than the market as a whole.

Q. IN GENERAL, ARE THERE CONCERNS REGARDING THE USE OF THE CAPM IN ESTIMATING THE RETURN ON EQUITY?

A. Yes. There is some controversy surrounding the use of the CAPM and its accuracy regarding expected returns. There is substantial evidence that beta is not the primary factor for determining the risk of a security. For example, Value Line's "Safety Rank" is a measure of total risk, not its calculated beta coefficient. Beta coefficients usually describe only a small amount of total investment risk. Dr. Burton Malkiel, author of *A Random Walk Down Wall Street* noted the following in his best-selling book on investing:

> Second, as Professor Richard Roll of UCLA has argued, we must keep in mind that it is very difficult (indeed probably impossible) to measure beta with any degree of precision. The S&P 500 Index is not "the market." The Total Stock Market contains many thousands of additional stocks in the United States and thousands more in foreign countries. Moreover, the total market includes bonds, real estate, commodities, and assets of all sorts, including one of the most important assets any of us has - the human capital built up by education, work, and life experience. Depending on exactly how you measure "the market" you can obtain very different beta values.[6]

Pratt and Grabowski also stated the following with respect to the CAPM:[7]

> Even though the capital asset pricing model (CAPM) is the most widely used method of estimating the cost of equity capital, the accuracy and predictive power of beta as the sole measure of risk have increasingly come under attack. As a result, alternative measures of risk have been proposed and tested. That is, despite its wide adoption, academics and practitioners alike have questioned the usefulness of CAPM in accurately estimating the cost of equity capital and the use of beta as a reliable measure of risk.

As a practical matter, there is substantial judgment involved in estimating the required market return and market risk premium. In theory, the CAPM requires an estimate of the return on the total market for investments, including stocks, bonds, real estate, etc. It is nearly impossible for the analyst to estimate such a broad-based return. Often in utility cases, a market return is estimated using the S&P 500. However, as Dr. Malkiel pointed out, this is a limited source of information with respect to estimating the investor's required

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[6] *A Random Walk Down Wall Street*, Burton G. Malkiel, page 218, 2019 edition.
[7] *Cost of Capital*, Shannon Pratt and Roger Grabowski, 5th Edition, page 288, published by Wiley.

return for all investments. In practice, the total market return estimate faces significant limitations to its estimation and, ultimately, its usefulness in quantifying the investor required ROE.

In the final analysis, a considerable amount of judgment must be employed in determining the market return and expected risk premium elements of the CAPM equation. The analyst's application of judgment can significantly influence the results obtained from the CAPM. My past experience with the CAPM indicates that it is prudent to use a wide variety of data in estimating investor-required returns. Of course, the range of results may also be wide, indicating the difficulty in obtaining a reliable estimate from the CAPM.

Q. HOW DID YOU ESTIMATE THE MARKET RETURN AND MARKET RISK PREMIUM OF THE CAPM?

A. I used two approaches to estimate the market risk premium portion of the CAPM equation. One approach uses the expected return on the market and is forward-looking. The other approach employs an historical risk premium based on actual stock and bond returns from 1926 through 2018.

Q. PLEASE DESCRIBE YOUR FORWARD-LOOKING APPROACH TO ESTIMATING THE MARKET RISK PREMIUM.

A. The first source I used was the Value Line Investment Analyzer Plus Edition, for February 25, 2020. This edition covers several thousand stocks. The Value Line Investment Analyzer provides a summary statistical report detailing, among other things, forecasted growth rates for earnings and book value for the companies Value Line follows as well as the projected total annual return over the next 3 to 5 years. I present these growth rates and Value Line's projected annual returns on page 2 of Exhibit RAB-4. I included median earnings and book value growth rates. The estimated market returns using Value Line's market data range from 10.35% to 12.71%. The average of these market returns is 11.53%.

Q. WHY DID YOU USE MEDIAN GROWTH RATE ESTIMATES RATHER THAN THE AVERAGE GROWTH RATE ESTIMATES FOR THE VALUE LINE COMPANIES?

A. Using median growth rates is likely a more accurate approach to estimating the central tendency of Value Line's large data set compared to the average growth rates. Average earnings and book value growth rates may be unduly influenced by very high or very low 3–5-year growth rates that are unsustainable in the long run. For example, Value Line's Statistical Summary shows both the highest and lowest value for earnings and book value growth forecasts. For earnings growth, Value Line showed the highest earnings growth forecast to be 92.5% and the lowest growth rate to be -13.5%. With respect to book value, the highest growth rate was 84% and the lowest was a -29.5%. None of these growth rate projections is compatible with long-run growth prospects for the market as a whole. The median growth rate is not influenced by such extremes because it represents the middle value of a very wide range of earnings growth rates.

Q. PLEASE CONTINUE WITH YOUR MARKET RETURN ANALYSIS.

A. I also considered a supplemental check to the Value Line projected market return estimates. Duff and Phelps compiled a study of historical returns on the stock market in its *2019 Valuation Handbook - U.S. Guide to Cost of Capital*, which is now part of its Cost of Capital Navigator subscription service. Some analysts employ this historical data to estimate the market risk premium of stocks over the risk-free rate. The assumption is that a risk premium calculated over a long period of time is reflective of investor expectations going forward. Exhibit RAB-5 presents the calculation of the market returns and market risk premiums using the historical data from Duff and Phelps.

Q. PLEASE EXPLAIN HOW THIS HISTORICAL RISK PREMIUM IS CALCULATED.

A. Exhibit RAB-5 shows the arithmetic average of yearly historical stock market returns over the historical period from 1926 – 2018. The average annual income return for 20-year Treasury bond is subtracted from these historical stock returns to obtain the historical market risk premium of stock returns over long-term Treasury bond income returns. The resulting historical market risk premium is 6.9%.

Q. DID YOU ADD AN ADDITIONAL MEASURE OF THE HISTORICAL RISK PREMIUM IN THIS CASE?

A. Yes. Duff and Phelps reported the results of a study by Dr. Roger Ibbotson and Dr. Peng Chen indicating that the historical risk premium of stock returns over long-term government bond returns has been significantly influenced upward by substantial growth in the price/earnings ("P/E") ratio.[8] Duff and Phelps noted that this growth in the P/E ratio for stocks was subtracted out of the historical risk premium to arrive at an adjusted "supply side" historical arithmetic market risk premium is 6.14%, which I have also included in Exhibit RAB-5.

Q. HOW DID YOU DETERMINE THE RISK FREE RATE?

A. I used two different measures for the risk-free rate. The first measure is the average 30-year Treasury Bond yield for the six-month period from September 2019 through February 2020. This represents a current measure of the risk-free rate based on actual current Treasury yields, which is 2.19%.

The second measure comes from Duff and Phelps' most recent "normalized" risk-free rate of September 30, 2019.[9] Duff and Phelps developed this normalized risk-free rate using its measure of the "real risk free rate" and expected inflation. The Duff and Phelps normalized risk-free rate is 3.0%.

Q. PLEASE SUMMARIZE YOUR CALCULATED MARKET RISK PREMIUM ESTIMATES WITH THE FORWARD-LOOKING DATA FROM VALUE LINE AND THE HISTORICAL DUFF AND PHELPS EQUITY RISK PREMIUMS.

A. My market risk premiums from Exhibits RAB-4 and RAB-5 are as follows:

- Forward-looking risk premiums 8.53% - 9.34%
- Historical risk premium 6.14% - 6.90%

[8] *2019 Cost of Capital: Annual U.S. Guidance and Examples,* Duff and Phelps, Cost of Capital Navigator, Chapter 3, pp. 45 - 47.
[9] https://www.duffandphelps.com/insights/publications/valuation/us-normalized-risk-free-effective-september-30-2019

By way of comparison, Duff and Phelps currently recommends an equity risk premium of 5.5%, which resulted in a base U.S. cost of capital estimate of 8.5%. Based on this comparison, my range of equity risk premium estimates are certainly not conservative or understated.

Q. HOW DID YOU DETERMINE THE VALUE FOR BETA?

A. I obtained the betas for the companies in the proxy group from most recent Value Line reports. The average of the Value Line betas for the proxy group is 0.56.

Q. PLEASE SUMMARIZE THE CAPM RESULTS.

A. For my forward-looking CAPM return on equity estimates, the CAPM results are 7.40% – 7.75%. Using historical risk premiums, the CAPM results range from 5.61% – 6.85%.

Q. DO YOU HAVE ANY COMMENTS REGARDING THE RESULTS OF THE CAPM AT THIS TIME?

A. Yes. The CAPM is currently producing results that are low under a reasonable range of equity risk premium estimates. Even if I had used Value Line's highest expected market return of 12.71% from Exhibit RAB-4 and the Duff and Phelps normalized risk-free rate, the CAPM result would have been:

$$CAPM = 3.0\% + .56\ (12.71\% - 3.0\%) = 8.44\%$$

This represents the top of the range for the CAPM, which is still substantially below my average DCF estimates. At this point, I cannot recommend that the Commission place substantial weight on the CAPM. Although Mr. Hevert presented CAPM results that are higher, his analysis has problems that I will discuss at length later in my testimony.

ROE Conclusions and Recommendations

Q. PLEASE SUMMARIZE THE COST OF EQUITY RESULTS FOR YOUR DCF AND CAPM ANALYSES.

A. Table 2 below summarizes my return on equity results using the DCF and CAPM for the proxy group of companies.

Table 2
SUMMARY OF ROE ESTIMATES

DCF Methodology	
Average Growth Rates	
- High	8.77%
- Low	8.46%
- Average	8.60%
Median Growth Rates:	
- High	9.02%
- Low	8.21%
- Average	8.67%
CAPM Methodology	
Forward-lookng Market Return:	
- Current 30-Year Treasury	7.40%
- D&P Normalized Risk-free Rate	7.76%
Historical Risk Premium:	
- Current 30-Year Treasury	5.61% - 6.04%
- D&P Normalized Risk-free Rate	6.43% - 6.85%

Q. DID YOU REVIEW RECENTLY ALLOWED EQUITY RETURNS FROM REGULATORY COMMISSIONS?

A. Yes. My Table 1, which is based on data from Mr. Hevert's Exhibit No. RBH-5, shows that the average commission allowed ROEs and 30-Year Treasury Bond yields for 2016, 2017, 2018, and 2019 were as follows:

- 2016: ROE - 9.60%, 30-Year Treasury - 2.62%

- 2017: ROE - 9.68%, 30-Year Treasury - 2.82%
- 2018: ROE - 9.56%, 30-Year Treasury - 2.99%
- 2019: ROE - 9.57%, 30-Year Treasury - 3.10%

I note that the average 30-year Treasury yields in these years were significantly higher than current long-term Treasury yields. Exhibit RAB-4 shows that the most recent six-month average 30-year Treasury Bond yield is only 2.19%, compared to the average yield in 2019 of 3.10%. With long-term Treasury yields so much lower over the last six month and even more so in March, it makes sense that the allowed ROE for regulated electric companies should decline as well.

Q. WHAT IS YOUR RECOMMENDED RETURN ON EQUITY FOR DUKE PROGRESS?

A. Based on my analysis in this case and the decline in long-term interest rates in the economy generally, I recommend that the Commission adopt a 9.00% return on equity for Duke Progress.

Q. PLEASE EXPLAIN HOW YOU ARRIVED AT YOUR RECOMMENDATION.

A. I began with the average DCF ROE results in Table 2 and also considered the top end of my DCF range, which is 9.02%. In recommending 9.0%, I recognize that recent Commission allowed returns are higher than my DCF results. However, I do not recommend that the Commission base its allowed ROE on the average allowed ROEs in other states. Such an approach would not be based on the specific evidence and circumstances presented in this case. Nevertheless, my recommendation of 9.0% is reasonably close to recently allowed ROEs and is fully based on the market evidence and analysis I reviewed.

I also considered the comments from the Value Line Investment Survey I quoted in Section II of my Direct Testimony, which stated that valuations for utility stocks are already within their forecasted levels for the 2023 – 2025 time period. My recommendation of 9.0% allows for some risk of declines in the stock prices of the companies in the proxy group given the current high valuations mentioned by Value Line.

Q. PLEASE COMMENT ON THE RECENT VOLATILITY IN FINANCIAL MARKETS IN MARCH 2020 AND HOW THIS VOLATILITY IMPACTS YOUR RECOMMENDED ROE IN THIS PROCEEDING.

A. In March, the stock market underwent a steep, sharp decline of approximately 19% due primarily to the coronavirus pandemic. Utilities have also declined in March, with the Dow Jones utility average declining from 886.52 on March 2 to 737.25 on March 18, a decline of about 17% with substantial volatility, or changes to the index's value, within the month. The yield on the 30-Year Treasury bond yield declined substantially as well, falling from 1.97% in February to 1.35% on March 31 with the yield reaching a low of 0.99% on March 9. Corporate bond yields, however, rose sharply in March, reflecting underlying concerns about increasing risk of default due to a possible recession.

It is too early to tell what impact this extreme market break would have on my recommendation. Given the ongoing volatility and concomitant uncertainty in March and April, I will continue to evaluate the situation in coming weeks and reserve the right to supplement my analyses and recommendations to the Commission if necessary before evidentiary hearings begin.

Q. WHAT CAPITAL STRUCTURE IS DUKE PROGRESS REQUESTING IN THIS CASE?

A. Company witness Newlin recommended a capital structure consisting of 53% common equity and 47% long-term debt. Mr. Newlin testified that this capital structure "will help DE Progress maintain its credit quality" and that it is "consistent with the Company's target credit ratings for DE Progress."[10]

Q. DID MR. NEWLIN OR DUKE PROGRESS PERFORM ANY ANALYSES THAT SUPPORT THE NEED FOR A 53% COMMON EQUITY RATIO TO SUPPORT ITS CREDIT QUALITY AND BOND RATINGS OR THAT THIS CAPITAL STRUCTURE MINIMIZES THE COMPANY'S COST OF CAPITAL?

A. No. Please refer to Exhibit RAB-6, which contains Duke Progress' response to Data Request No. 24, Item No. 24-4 from the North Carolina Public Staff. This data request sought support from the Company that its requested capital structure minimizes the weighted average cost of capital. The Company responded as follows:

> "Duke Energy Progress targets stable 'A' level credit ratings on an unsecured basis. The Company has not performed the studies requested, but instead considers both quantitative and qualitative factors in its assessment of capital structure. In his testimony,

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10 Direct Testimony of Karl Newlin, page 22, lines 6 through 8.

> witness Newlin notes the Company "…believes this proposed capital structure is optimal for DE Progress, as it introduces an appropriate amount of risk due to leverage while minimizing the weighted average cost of capital to customers." While reducing the equity component would minimize the WACC on paper, it also increases leverage and risk, reduces cash flow, negatively impacts credit quality, and would increase the cost of debt and equity capital. In order to finance operations at favorable rates through all market conditions, the Company must balance risk due to leverage and cost to customers. In the Company's judgment, the proposed 47/53 capital structure supports those ratings, and impacts the quantitative and qualitative analysis performed by Moody's and S&P. Please refer to the Company's credit rating reports, included in PS DR 22-4, for quantitative analysis performed by the rating agencies."

Although the Company referred the Public Staff to quantitative analyses performed by the rating agencies, it did not have any of its own studies to support Mr. Newlin's assertion that the requested 53% common equity ratio minimizes the cost of capital for ratepayers or was necessary to maintain its credit ratings. Instead, this response pointed to unspecified "quantitative and qualitative factors" in the assessment of its capital structure. In my opinion, Duke Progress has not shown that a 53% equity ratio is prudent and necessary, or that it minimizes the cost of capital for the Company and its ratepayers.

Q. DO YOU RECOMMEND THAT THE COMMISSION ACCEPT THE COMPANY'S REQUESTED CAPITAL STRUCTURE?

A. No. I recommend that the Commission adopt a capital structure weighted with 51.5% common equity and 48.5% long-term debt. This recommendation is consistent with my recommendation for Duke Energy Carolinas in E-4, Sub 1214.

Q. HOW DOES DUKE PROGRESS' REQUESTED 53% COMMON EQUITY RATIO COMPARE TO THE 2018 COMMON EQUITY RATIOS OF THE PROXY GROUP USED BY YOU AND MR. HEVERT?

A. Table 3 below shows the 2018 common equity ratios for each company in the proxy group as well as the average common equity ratio for the group.

Table 3
Proxy Group 2018 Common Equity Ratios

ALLETE, Inc.	60.1%
Alliant Energy Corporation	46.7%
Ameren Corp.	48.8%
American Electric Power Co.	46.8%
Avangrid, Inc.	73.8%
CMS Energy Corporation	30.7%
DTE Energy Company	45.8%
Evergy, Inc.	60.0%
Hawaiian Electric	51.7%
NextEra Energy, Inc.	56.0%
Northwestern Corporation	47.8%
OGE Energy Corp.	58.0%
Otter Tail Corporation	55.3%
Pinnacle West Capital Corp.	53.0%
PNM Resources, Inc.	38.6%
Portland General Electric Company	53.5%
Southern Company	37.6%
WEC Energy Group	49.4%
Xcel Energy Inc.	43.6%
Average	50.4%

Source: Value Line Investment Survey

The average common equity ratio for the proxy group is 50.4%, lower than Duke Progress' requested 53% equity ratio and lower than my recommended equity ratio of 51.5%. This indicates that my recommended 51.5% equity ratio is reasonable compared to the average for the proxy group.

Q. IS YOUR RECOMMENDED EQUITY RATIO OF 51.5% CONSISTENT WITH AVERAGE ALLOWED EQUITY RATIOS BY OTHER REGULATORY COMMISSIONS?

A. Yes. In his Rebuttal Testimony in Docket No. E-7, Sub 1214 Mr. Hevert testified that the average and median authorized equity ratios for vertically integrated utilities in 2019 was 50.20% and 52%, respectively.[11]

Q. IS YOUR RECOMMENDED EQUITY RATIO OF 51.5% CONSISTENT WITH RECENTLY ALLOWED COMMON EQUITY RATIOS BY THE NORTH CAROLINA UTILITIES COMMISSION?

A. Yes. In Mr. Hevert's aforementioned Rebuttal Testimony, he testified that the Commission authorized common equity ratios of 52% for Dominion Energy North Carolina, Duke Progress, Duke Energy Carolinas, and Piedmont Natural Gas.[12]

Q. WHAT IS YOUR RECOMMENDED WEIGHTED COST OF CAPITAL FOR DUKE PROGRESS?

A. My recommended weighted cost of capital is presented in Table 4. I used my recommended capital structure, the Company's cost of debt of 4.15%, and my recommended ROE of 9.0%. The weighed cost of capital is 6.65%.

Table 4
Recommended Weighted Cost of Capital

	Capital Ratio	Component Costs	Weighted Avg Cost
Long Term Debt	48.50%	4.15%	2.01%
Common Equity	51.50%	9.00%	4.64%
Total Capital	100.00%		6.65%

[11] Refer to the Rebuttal Testimony of Robert Hevert, page 180, lines 18 through 21, Docket No. E-7, Sub 1214.
[12] Refer to the Rebuttal Testimony of Robert Hevert, page 105, line 19 through page 106, line 1, Docket No. E-7, Sub 1214.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT ON DUKE PROGRESS' NORTH CAROLINA RATEPAYERS FROM MR. HEVERT'S RECOMMENDED 10.5% ROE AND THE COMPANY'S PROPOSED 53% EQUITY RATIO COMPARED TO YOUR RECOMMENDATION?

A. The rate impact on North Carolina customers is substantial. Exhibit RAB-7 presents my calculation of the increased revenue requirement from the Company's requested ROE of 10.3% and common equity ratio of 53% compared to my recommended overall cost of capital. My analysis uses the Company's requested rate base and the tax rates, the NCUC fee percentage, and the uncollectible rate from the Company's Smith Exhibit 1. *Duke Progress' requested return on rate base would cost North Carolina ratepayers an additional $110.14 million per year in their rates compared to my recommendation.* Clearly, Duke Progress' proposed capital structure and requested ROE do not minimize the cost of capital for ratepayers, are unreasonable, and should be rejected by the Commission. I noted that although Duke Progress seeks approval of a 10.3% ROE that is lower than Mr. Hevert's recommendation, this slightly lower ROE is still too high and imposes an undue burden on the Company's ratepayers.

In conclusion and based on my analyses through February 2020, a 9.00% ROE and an imputed 51.5% common equity ratio is more than adequate to meet *Hope* and *Bluefield* standards with respect to comparable returns, financial integrity and ability to attract capital. It will also satisfy the requirement for the Commission's consideration of the economic impact on North Carolina ratepayers from the allowed rate of return in this case. As I mentioned earlier in my testimony, I will continue to evaluate financial markets and reserve the right to update and revise my testimony and recommendations prior to the scheduled hearing in this proceeding.

IV. ECONOMIC CONDITIONS IN NORTH CAROLINA

Q. PLEASE DISCUSS MR. HEVERT'S ANALYSIS OF ECONOMIC CONDITIONS IN NORTH CAROLINA.

A. Mr. Hevert presented his analysis of North Carolina's economic conditions beginning on page 53 of his Direct Testimony. As a preliminary matter, Mr. Hevert set forth the Commission's considerations with respect to balancing the interests of investors and ratepayers in setting the allowed ROE for North Carolina utilities.[13] With respect to his economic analysis, Mr. Hevert reached the following main conclusions:[14]

- North Carolina's unemployment rate has fallen by two-thirds since its peak in 2009-2010 and as of July 2019 the unemployment rate stood at 4.20%, which is slightly higher than the national average.
- The unemployment rate in the counties served by Duke Progress fell considerably since its peak in 2010.
- North Carolina's Gross Domestic Product ("GDP") is "highly correlated" with national GDP.

[13] State of North Carolina Utilities Commission, Docket No. E-7, Sub 989, Order on Remand, October 23, 2013, at 34 - 35; Dominion Remand Order, Docket No. E-22, Sub 479 at 26.
[14] Refer to pages 61 through 63 of Mr. Hevert's Direct Testimony.

- Median household income has grown in North Carolina and has grown at a rate consistent with the national average median income. Also, the overall cost of living in North Carolina is below the national average.
- North Carolina residential electricity rates have been approximately 8.28% below the national average over the last 15 years.

Based on his analysis, Mr. Hevert concluded on page 62 of his Direct Testimony that his recommended 10.5% ROE is "fair and reasonable to DE Progress, its shareholders, and its customers in light of the effect of those changing economic conditions."

Q. PLEASE PRESENT YOUR CONCLUSIONS WITH RESPECT TO THE STUDY CONDUCTED BY MR. HEVERT.

A. My main conclusions are:

- Although the growth in median income in North Carolina is correlated with the national average, the median income in North Carolina and the counties served by Duke Progress is significantly lower than the national average.
- Duke Progress' lower than average residential rates and North Carolina's lower than average cost of living do not justify the Company's excessive requested ROE and overall cost of capital.

Q. PLEASE ADDRESS YOUR CONCLUSION WITH RESPECT TO UNEMPLOYMENT RATES FOR NORTH CAROLINA AND THE UNITED STATES AS A WHOLE.

A. As Mr. Hevert pointed out in his Direct Testimony, North Carolina's unemployment rate fell as the overall U.S. unemployment rate fell, although North Carolina's unemployment rate was 0.50% higher as of July 2019. As of December 2019, the seasonally adjusted U.S. unemployment rate was 3.50% and the North Carolina unemployment rates was 3.60%, according to the U.S. Bureau of Labor Statistics.[15] I also reviewed Mr. Hevert's data supporting his unemployment analysis in Chart 4 on page 56 of his Direct Testimony. Table 5 below presents Mr. Hevert's monthly unemployment rate data from January 2018 through July 2019.

Table 5
Unemployment Rate Comparison

	U.S. Unemployment Rate	N.C. Unemployment Rate	Difference
Jan-2018	4.10	4.20	0.10
Feb-2018	4.10	4.20	0.10
Mar-2018	4.00	4.10	0.10
Apr-2018	3.90	4.00	0.10
May-2018	3.80	4.00	0.20
Jun-2018	4.00	3.90	(0.10)
Jul-2018	3.90	3.80	(0.10)
Aug-2018	3.80	3.70	(0.10)
Sep-2018	3.70	3.70	-
Oct-2018	3.80	3.70	(0.10)
Nov-2018	3.70	3.70	-
Dec-2018	3.90	3.70	(0.20)
Jan-2019	4.00	3.80	(0.20)
Feb-2019	3.80	3.90	0.10
Mar-2019	3.80	4.00	0.20
Apr-19	3.60	4.00	0.40
May-19	3.60	4.10	0.50
Jun-19	3.70	4.20	0.50
Jul-19	3.70	4.20	0.50

Source: Mr. Hevert's work papers

Note that the "Difference" column presents the difference between the North Carolina unemployment rate and the U.S. unemployment rate. In January 2018,

[15] The North Carolina unemployment rate was preliminary as of the preparation of my Direct Testimony.

for example, the North Carolina unemployment rate was higher than the national average, resulting in positive 0.10 difference. From July 2018 through January 2019 North Carolina's unemployment rate was lower than the national average, then went back above the national average in February 2019. North Carolina's unemployment rate has declined since Mr. Hevert filed his testimony in this case and is now roughly equal to the national average.

Q. PLEASE COMMENT ON THE DIFFERENCE IN MEDIAN INCOME BETWEEN THE NATIONAL AVERAGE AND NORTH CAROLINA.

A. The data underlying Mr. Hevert's median income comparison shows that North Carolina's median income has been persistently and significantly below the U.S. median income during the entire study period. Table 6 below presents U.S. and North Carolina median income and the percentage difference between them. This data was taken from Mr. Hevert's work papers.

Table 6
Median Income Comparison

Year	U.S. Median Income	N.C. Median Income	Difference
2018	63,179	53,369	-15.5%
2017	61,136	49,547	-19.0%
2016	59,039	53,764	-8.9%
2015	56,516	50,797	-10.1%
2014	53,657	46,784	-12.8%
2013	53,585	46,337	-13.5%
2012	51,017	41,553	-18.6%
2011	50,054	45,206	-9.7%
2010	49,276	43,830	-11.1%
2009	49,777	41,906	-15.8%
2008	50,303	42,930	-14.7%
2007	50,233	43,513	-13.4%
2006	48,201	39,797	-17.4%
2005	46,326	42,056	-9.2%

Source: Mr. Hevert's work papers

Table 6 shows that the difference between the North Carolina and U.S. median income levels has grown from -8.9% in 2016 to -19.0% in 2017 and -15.5% in 2018. These differences underscore the importance of setting the allowed ROE and the overall cost of capital as low as possible while still satisfying the legal requirements of *Hope* and *Bluefield* and the North Carolina Supreme Court's finding with respect to return on equity.

Q. DO YOU HAVE ANY CONCLUDING COMMENTS REGARDING THE ECONOMIC CONDITIONS IN NORTH CAROLINA AT THIS TIME?

A. Yes. Governor Cooper issued executive orders in March that closed all public schools and that ordered bars, restaurants, cafes, etc. to cease all dine-in operations and issued a "shelter-in-place" Order effective on March 30 for the entire state. So-called "social distancing" is becoming the norm both statewide and nationally. North Carolina's and the United States' response to controlling the spread of the novel coronavirus is still ongoing, but these efforts are certain to drastically curtail economic activity in North Carolina and nationwide. The impact on state and national Gross Domestic Product, median income, and unemployment cannot as yet be measured, but it is reasonable to expect that unemployment will increase significantly, with likely decreases in median income for North Carolinians. I will continue to monitor the economic impacts of our state's and nation's attempts to address this growing pandemic and, to the extent possible, update my analyses before the start of the evidentiary hearing. However, now more than ever it is important to consider the impacts of the Company's requested ROE of 10.3% - 10.5% on North Carolina ratepayers.

V. RESPONSE TO DUKE PROGRESS' DIRECT TESTIMONY

Q. HAVE YOU REVIEWED THE DIRECT TESTIMONY OF MR. ROBERT HEVERT?

A. Yes.

Q. PLEASE SUMMARIZE MR. HEVERT'S TESTIMONY AND APPROACH TO RETURN ON EQUITY.

A. Mr. Hevert employed three methods to estimate the investor required rate of return for Duke Progress: (1) the constant growth DCF model, (2) the CAPM and the empirical CAPM ("ECAPM"), and (3) the Bond Yield Plus Risk Premium model ("BYRP"). Mr. Hevert also presented the results of the Expected Return approach based on Value Line's forecasted returns on book equity for the proxy group.

For his constant growth DCF approach, Mr. Hevert used Value Line, First Call, and Zacks for the investor expected growth rate. For the proxy group, Mr. Hevert's mean growth rate ROE results ranged from 8.78% to 8.97%.[16]

With respect to the CAPM, Mr. Hevert utilized a current and near-term projected yield on the 30-Year Treasury Bond for his risk-free rate. Using the current Treasury bond yield of 2.43%, his CAPM results ranged from 8.44% to 9.41%. Using the near-term projected Treasury yield of 2.65%, his CAPM results ranged from 8.66% to 9.62%.[17]

[16] Refer to Mr. Hevert's Direct Testimony, page 84, Table 7.
[17] *Id.*, page 91, Table 8.

Mr. Hevert's ECAPM variation of the CAPM yielded results ranging from 9.95% to 10.93%.[18]

Finally, Mr. Hevert's formulation of the BYRP approach resulted in a ROE range of 9.91% - 10.06%.[19]

Based on the results of his analyses and judgment, Mr. Hevert recommended a ROE range for Duke Progress of 10.00% to 11.00%, concluding that the cost of equity is 10.50%.[20]

Q. BEFORE YOU PROCEED TO THE PARTICULARS OF YOUR REVIEW OF MR. HEVERT'S TESTIMONY, WHAT IS YOUR OVERALL CONCLUSION WITH RESPECT TO MR. HEVERT'S RECOMMENDED ROE RANGE?

A. Mr. Hevert's recommended ROE range of 10.00% – 11.00% only partially reflects the full range of results from his analyses. His mean DCF results, which are fairly consistent with mine, were completely excluded from his range of recommendations. Based on the ROE results presented by Mr. Hevert, it appears that he mainly relied on the results of the ECAPM and his BYRP method to establish the bounds of his recommended ROE range.

To put this another way, consider the following:

- Mr. Hevert rejected the mean results from the constant growth DCF in total.

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[18] *Id.*, page 96, Table 9.

[19] *Id.*, page 100, Table 10.

[20] *Id.*, page 13.

- Mr. Hevert also apparently rejected his CAPM results given that the top end of his CAPM range was 9.62%.

What we are left with, then, is the BYRP results of 9.91% - 10.06% being consistent with Mr. Hevert's floor recommendation of 10.0%. His ECAPM results also fall within his recommended range. Although Mr. Hevert presented three different approaches to estimating the cost of equity for Duke Progress, he omitted the DCF model and CAPM results and relied almost exclusively on the ECAPM and BYRP.

Q. IS IT APPROPRIATE FOR MR. HEVERT TO REJECT THE MEAN RESULTS FROM HIS DCF ANALYSES?

A. No. It is inappropriate for Mr. Hevert to exclude the mean results of the constant growth DCF model in his recommended ROE for Duke Progress. The constant growth DCF model utilizes verifiable public information with respect to investor return requirements for electric utilities. Current stock prices are the best indicators we have of investor expectations and analysts' earnings and dividend growth forecasts may reasonably be assumed to influence investors' required ROEs. Discarding this important publicly available information as Mr. Hevert has done serves to significantly overstate his recommended investor required return for a low-risk regulated utility company such as Duke Progress. The DCF model currently shows that investor required returns are considerably lower for utility stocks given their safety and security relative to the stock market as a whole.

Q. IS USING THE HIGH MEAN RESULTS FROM THE DCF MODELS APPROPRIATE?

A. No. Mr. Hevert's high mean results simply use the highest ROE for each company in the proxy group, which is driven by the highest expected growth rate. There is no basis for assuming that investors are more likely to expect the highest growth rate from the three sources used by Mr. Hevert. The average of the three sources is a far more likely and reasonable assumption. For example, the proxy group high mean using Mr. Hevert's 180-day average stock price is unduly influenced by excessive ROE estimates for Avangrid (13.69%), NextEra Energy (13.24%), and Otter Tail (11.90%).[21]

Q. ON PAGE 84, LINES 9 THROUGH 16 OF HIS DIRECT TESTIMONY, MR. HEVERT CRITICIZED THE USE OF THE DCF MODEL ON CERTAIN GROUNDS. PLEASE ADDRESS MR. HEVERT'S CRITICISMS.

A. Mr. Hevert testified that the DCF model is predicated on a number of assumptions, one being a constant price/earnings (P/E) ratio. Since P/E ratios in the utility sector are currently above their long-term average and the market's P/E, Mr. Hevert recommended caution when viewing the DCF results. Mr. Hevert also testified that the DCF model is producing results below the authorized returns for electric utilities.

First, before I proceed to a more detailed response to Mr. Hevert's criticisms of the DCF model's assumptions, it is important to realize that none

[21] *See* Exhibit RBH-1, page 3 of 3.

of the models Mr. Hevert and I use to estimate the investor required ROE strictly adhere to their underlying assumptions 100% of the time in the real world. The DCF, CAPM, and risk premium models all operate with certain simplifying assumptions. In Section III of my testimony I pointed out the limitations of the CAPM that must be considered in assessing its effectiveness relative to the DCF model. One of those limitations is estimating the market required rate of return. Estimating the market required rate of return requires considerable judgment on the part of the analyst, judgment that may result in a wide range of possible returns. In this case, Mr. Hevert and I used very different estimates of the market rate of return that caused our CAPM results to differ considerably. I will address the serious underlying problems with Mr. Hevert's CAPM later in my testimony.

I suggest that the Commission recognize that no ROE estimation model strictly adheres to its underlying assumptions all the time.

Q. PLEASE CONTINUE WITH YOUR RESPONSE TO MR. HEVERT'S CRITICISM OF THE DCF MODEL'S ASSUMPTIONS.

A. With respect to the assumption of a constant P/E ratio, simply because the utility industry's current P/E ratio may be above the long-term average P/E ratio does not mean that the DCF results based on current data are questionable and should be thrown out. As I have stated previously in my testimony, capital markets are efficient and can be assumed to reflect investor preferences in the prices they are willing and able to pay for a regulated utility's common stock. This includes publicly available information to which investors have access, including P/E ratios. What this means is that it is reasonable to assume that current stock prices are reflective of investors' required ROE and that the DCF model can provide valid and valuable information to the Commission in its determination of the allowed ROE for regulated utilities generally and for Duke Energy Progress in this case.

Q. ON PAGE 85, LINES 10 THROUGH 19 OF HIS DIRECT TESTIMONY, MR. HEVERT TESTIFIED THAT THE DCF MODEL ASSUMES THAT THE RETURN TODAY WILL BE THE SAME RETURN REQUIRED IN THE FUTURE, "EVEN THOUGH THE FEDERAL RESERVE ONLY RECENTLY HAS COMPLETED THE PRINCIPAL INITIATIVES OF ITS MONETARY POLICY NORMALIZATION AND IS CONTINUING TO ASSESS REALIZED AND EXPECTED ECONOMIC CONDITIONS AS IT DETERMINES FUTURE ADJUSTMENTS, INTRODUCING A DEGREE OF UNCERTAINTY REGARDING FUTURE MONETARY POLICY ACTIONS." PLEASE COMMENT ON THIS STATEMENT.

A. Again, it is highly likely that investors have fully taken this information into account into the prices they are willing to pay for bonds and utility stocks. The Fed lowered the federal funds rate several times in 2019 and long-term Treasury yields have fallen significantly. During 2019, the 30-year Treasury bond yield fell from 3.04% in January to 2.3% December and even further in February 2020 to 1.97%. Clearly, the trend in the economy over the last year shows that capital costs are declining, not increasing, and one would expect that investor required ROEs for low-risk regulated electric utilities like Duke Progress would follow that trend.

Furthermore, all of the models used to estimate the investor's required ROE must fix a return "today" since no one knows with certainty what will happen in the future, including what investor expected returns will be. Future events and economic conditions will affect the required ROE in ways we cannot predict now.

Q. ON PAGE 86 OF HIS DIRECT TESTIMONY, MR. HEVERT TESTIFIED THAT SINCE 1980 ONLY ELEVEN UTILITY RATE CASES INCLUDED AN AUTHORIZED ROE OF LESS THAN 9.0%. PLEASE RESPOND TO MR. HEVERT'S TESTIMONY ON THIS POINT.

A. Including rate cases since 1980 is an irrelevant exercise because it places too much emphasis on stale data. In the 1980s and 1990s interest rates and allowed ROEs were far higher than they have been in the last few years. Consider the following information I developed using the data in Mr. Hevert's Exhibit RBH-5:

- From 1980 through 1989, the average awarded ROE was 14.80% and the average 30-Year Treasury Bond yield was 11.35%.
- From 1990 through 1999, the average awarded ROE was 11.91% and the average 30-Year Treasury Bond yield was 7.51%.
- From 2000 through 2009, the average awarded ROE was 10.62% and the average 30-Year Treasury Bond yield was 4.81%.

These averages give the Commission a general picture of the interest rate and ROE levels from the 1980s, 1990s, and 2000s and represent 1,218 of the 1,594 observations in Mr. Hevert's data set in Exhibit RBH-5. They are in no way indicative of investor required returns today given how much higher 30-Year Treasury yields were during these prior periods.

Further consider that Mr. Hevert's recommendation of 10.5% is close to the average ROE from 2000 – 2009 of 10.62%. During that period the average 30-year Treasury Bond yield was 4.81%, which is 284 basis points, or 2.94% higher than the February 2020 yield of 1.97%. With Treasury Bond yields so much lower now, Mr. Hevert's ROE recommendation of 10.5% is clearly out of line and unsupportable using current market conditions.

Q. ON PAGE 84, LINES 14 THROUGH 16 OF HIS DIRECT TESTMONY MR. HEVERT TESTIFIED THAT THE MEAN CONSTANT GROWTH DCF RESULTS ARE BELOW THE AUTHORIZED RETURN FOR ELECTRIC UTILITIES. HOW DO MR. HEVERT'S ECAPM RESULTS COMPARE WITH RECENT AUTHORIZED RETURNS?

A. Mr. Hevert's ECAPM ROEs are based on the average Value Line beta range from 10.61% to 10.93% and are consistent with the upper end of Mr. Hevert's recommended ROE range. These results are grossly in excess of ROEs allowed in the last several years, a so-called "benchmark" Mr. Hevert used to criticize the DCF model. Based on the authorized ROE data in Exhibit RBH-5, one would have to go back to 2011 to find an authorized ROE near or above 11.0%. Although Mr. Hevert criticized the DCF model results for being below authorized returns, he did not apply the same criterion to test whether his ECAPM results were reasonable.

Q. CONSIDERING THE FOREGOING DISCUSSION, PLEASE SUMMARIZE YOUR CONCLUSIONS WITH RESPECT TO MR. HEVERT'S RECOMMENDED ROE RANGE AND HIS ROE RECOMMENDATION FOR DUKE PROGRESS.

A. I conclude that the Commission should reject Mr. Hevert's recommended ROE range and his recommended ROE of 10.50%. Mr. Hevert's 10.50% ROE recommendation is excessive in today's market environment. Mr. Hevert's ROE range omits critically important information from the DCF model and CAPM and, as a result, misstates the investor required ROE for a low-risk utility such as Duke Progress.

<u>CAPM and ECAPM</u>

Q. BRIEFLY SUMMARIZE THE MAIN ELEMENTS OF MR. HEVERT'S CAPM APPROACH.

A. On pages 88 and 89 of his Direct Testimony, Mr. Hevert testified that he used two different measures of the risk-free rate: the current 30-day average yield on the 30-year Treasury bond (2.43%) and a near-term projected 30-year Treasury bond yield (2.65%). Mr. Hevert then calculated ex-ante measures of total market returns for the S&P 500 using data from Bloomberg and Value Line. Total market returns from these two sources were 14.48% using Bloomberg data and 14.62% return using Value Line data.[22] Subtracting out the risk-free rate, the resulting market risk premiums were 12.04% – 12.19%.

[22] Refer to Exhibit RBH-2.

Mr. Hevert used two different estimates for beta from Bloomberg (0.499) and Value Line (0.57).[23]

Q. IS IT APPROPRIATE TO USE FORECASTED OR PROJECTED BOND YIELDS IN THE CAPM?

A. No. Current interest rates and bond yields embody all of the relevant market data and expectations of investors, including expectations of changing future interest rates. The forecasted bond yield used by Mr. Hevert is at odds with the trend of declining long-term bond yields in 2019. Current interest rates provide tangible and verifiable market evidence of investor return requirements today and these are the interest rates and bond yields that should be used in both the CAPM and in the bond yield plus risk premium analyses. To the extent that investors give forecasted interest rates any weight at all, they are already incorporated in current securities prices.

In this case, however, Mr. Hevert's forecasted bond yield is not significantly different from his current bond yield. I would also note that current 30-year Treasury yields have declined since Mr. Hevert submitted his Direct Testimony, with a February 2020 yield of 1.97%. In comparison, my range for the risk-free rate is 2.19% – 3.00%, with a midpoint of 2.6%, so our estimates for the risk-free rate do not differ significantly in this proceeding.

Q. HOW DO MR. HEVERT'S ESTIMATES OF THE OVERALL MARKET RETURN COMPARE TO YOURS?

A. My estimates of the market required return are as follows:

[23] Refer to Exhibit RBH-3.

- Value Line 3-5 Year Total Return: 12.00% – 13.42%
- Value Line Growth Rates: 10.35%
- S&P Average Historical Returns: 11.90%

Mr. Hevert's forecasted market returns of 14.48% – 14.62% are extraordinarily high compared to historical norms. Further, his calculation of the market return using Value Line's 3 – 5 year earnings growth estimates greatly exceeds the Value Line 3 – 5 year total annual return numbers I used from the Value Line Investment Analyzer. Moreover, the number of companies the Value Line Investment Analyzer used to develop the total annual return numbers I used was 1,670, a far greater number of companies than the S&P 500 used by Mr. Hevert. I recommend that the Commission give Mr. Hevert's estimated market returns little weight in this proceeding.

Q. ARE THERE SOURCES OF WHICH YOU ARE AWARE THAT SUGGEST MR. HEVERT'S MARKET RISK PREMIUM RANGE OF 12.04% - 12.19% IS UNREASONABLY HIGH?

A. Yes. In the authoritative corporate finance textbook by Brealey, Myers, and Allen the authors stated:

> "Brealey, Myers, and Allen have no official position on the issue, but we believe that a range of 5 to 8 percent is reasonable for the risk premium in the United States."[24]

As I cited earlier in my Direct Testimony, Duff and Phelps currently recommends a market risk premium of 5.5% and an overall U. S. cost of equity of 8.5%. These sources underscore how much Mr. Hevert's recommended market risk premiums inflated his CAPM and ECAPM ROE estimates.

[24] Richard A. Brealey, Stewart C. Myers, and Paul Allen, *Principles of Corporate Finance*, page 154; McGraw-Hill/Irwin, 8th Edition, 2006.

Q. BEGINNING ON PAGE 92 OF HIS DIRECT TESTIMONY, MR. HEVERT EXPLAINED THAT HE ALSO INCLUDED THE ECAPM ANALYSIS. PLEASE COMMENT ON MR. HEVERT'S USE OF THE ECAPM IN THIS CASE.

A. The ECAPM is designed to account for the possibility that the CAPM understates the return on equity for companies with betas less than 1.0. Mr. Hevert explained on page 88 of his Direct Testimony how he applied the adjustment to his CAPM data, which was based on the formula included in *New Regulatory Finance* by Dr. Roger Morin.

The argument that an adjustment factor is needed to "correct" the CAPM results for companies with betas less than 1.0 is further evidence of the lack of accuracy inherent in the CAPM itself and with beta in particular, as I pointed out earlier in my Direct Testimony. The ECAPM adjustment also suggests that published betas by such sources as Value Line and Bloomberg are incorrect and that investors should not rely on them in formulating their estimates using the CAPM. Finally, although Mr. Hevert cited the source of the ECAPM formula he used, he provided no evidence that investors favor this version of the ECAPM over the standard CAPM.

Q. PLEASE COMMENT ON THE ECAPM RESULTS REPORTED BY MR HEVERT ON HIS TABLE 9 ON PAGE 96 OF HIS DIRECT TESTIMONY.

A. The ECAPM results using the Average Value Line beta Coefficient —10.61% to 10.93%—are excessive and implausible. To provide the Commission with some perspective here, according to the data presented by Mr. Hevert in his Exhibit RBH-5, there was one allowed ROE in 2017 that exceeded 11.0% and before that, the last Commission authorized ROE exceeding 11.00% was September 2, 2011 (12.88%) and that value far exceeded the other Commission allowed ROEs in 2011. I would also point out that the average 30-Year Treasury Bond yield in 2011 was 4.13%, a far higher yield than the recent 1.97% yield for the 30-Year Treasury Bond in February 2020. Mr. Hevert's ECAPM results using the Value Line beta are so excessive that they should be rejected out of hand by the Commission.

Risk Premium

Q. PLEASE SUMMARIZE MR. HEVERT'S RISK PREMIUM APPROACH.

A. Mr. Hevert developed an historical risk premium using Commission-allowed returns for regulated electric utility companies and 30-year Treasury Bond yields from January 1980 through August 16, 2019. He used regression analysis to estimate the value of the inverse relationship between interest rates and risk premiums during that period. Applying the regression coefficients to the average risk premium and using the current and projected 30-year Treasury yields I discussed earlier and also employing a long-term projected 30-year Treasury Bond yield of 3.70%, Mr. Hevert's risk premium ROE estimate range is 9.90% – 10.06%.[25]

Q. PLEASE RESPOND TO MR. HEVERT'S RISK PREMIUM ANALYSIS.

[25] Hevert Direct Testimony, page 100, Table 10.

A. There are two major flaws in Mr. Hevert's analysis. First, it measures the returns allowed by regulatory commissions, not investor required returns reflected in marketplace data; and second, it relies on historical allowed returns dating back to 1980 rather than recent returns. The bond yield plus risk premium approach is imprecise and can only provide very general guidance on the current authorized ROE for a regulated electric utility. Risk premiums can change substantially over time based on investor preferences and market conditions. These changes will not be incorporated into an historical risk premium analysis of the type Mr. Hevert uses that employs historical commission allowed ROEs. As such, this approach is a "blunt instrument," if you will, for estimating the ROE in regulated proceedings. In my view, a properly formulated DCF model using current stock prices and growth forecasts is far more reliable and accurate than the bond yield plus risk premium approach, which relies on a historical risk premium analysis based on the allowed returns over a certain period of time.

Q. DO MR. HEVERT'S RISK PREMIUM RESULTS ACCURATELY TRACK RECENTLY ALLOWED ROES?

A. No. Even assuming the Commission accepts the use of data about allowed ROEs as a substitute for market data, Mr. Hevert's model does not accurately track *recently* allowed ROE data. To test the accuracy of Mr. Hevert's BYRP model, I averaged the allowed returns and Treasury bond yields for 2018 as reported in Mr. Hevert's Exhibit RBH-5. The average allowed ROE for 2018 was 9.56% and the average 30-Year Treasury Bond yield was 2.99%. I then plugged in the 2.99% Treasury Bond yield to Mr. Hevert's BYRP formula in Exhibit RBH-5 and the resulting BYRP ROE was 9.92%. Compared to the actual average Commission-allowed 2018 ROE 9.56%, Mr. Hevert's formula overshot the actual ROE by 36 basis points, or 0.36%. Likewise using the December 2018 Treasury Bond yield of 2.30% in Mr. Hevert's BYRP formula results in a ROE of 9.93%, which is nearly identical to the 9.92% ROE result using a 2.99% Treasury Bond yield. It is clear that if the Treasury Bond yield falls, the expected ROE should also fall, but Mr. Hevert's BYRP formula result does not follow logically.

In my opinion, these calculations provide evidence to the Commission that using Mr. Hevert's risk premium model in today's economic environment will overstate the investor required ROE for a low-risk utility such as Duke Progress.

Expected Earnings

Q. BEGINNING ON PAGE 100 OF HIS DIRECT TESTIMONY, MR. HEVERT PRESENTED HIS EXPECTED EARNINGS ANALYSIS. PLEASE RESPOND TO MR. HEVERT'S ANALYSIS.

A. Mr. Hevert relied on Value Line's projected returns on book value equity for the period 2022-2024 for his expected earnings ROE estimate for the proxy group, which ranges from 10.47% – 10.54%.[26] He used the expected earnings analysis as a check on his other results.

[26] Mr. Hevert Direct Testimony, page 101.

The major flaw in the expected earnings approach is that it measures forecasted accounting returns on book value, not investor required returns in the marketplace. A market-based ROE estimation method like the DCF model uses stock market data and earnings growth forecasts to determine a forward-looking ROE estimate that incorporates true opportunity cost measured against the returns available to the investor in alternative investments such as other stocks, bonds, real estate, and so forth. Further, changes in economic variables such as interest rates will affect the required returns of utility stock investments and other investments as well. Such changes will be incorporated into the DCF and CAPM models, which use current market data. These changes will not be reflected in book returns on common equity.

Turning to Mr. Hevert's expected earnings approach, he provided absolutely no support for the assumption that Value Line's projected accounting returns on book value in the 2022 – 2024 projected time period have any influence whatsoever on required returns in today's financial marketplace or that they provide a useful benchmark in estimating current required returns. I recommend the Commission reject Mr. Hevert's expected earnings approach and instead use market-based ROE estimation models to set Duke Progress' allowed ROE in this proceeding.

Use of Multiple Methods to Estimate the Cost of Equity

Q. DID THE FEDERAL ENERGY REGULATORY COMMISSION ("FERC") RECENTLY ISSUE AN ORDER REGARDING USING MULTIPLE MODELS IN ESTIMATING THE ROE?

A. Yes. FERC recently issued its Opinion No. 569 on November 21, 2019, Docket Nos. EL14-12-003 and EL15-45-000 regarding the methods used to estimate a just and reasonable ROE under the Federal Power Act ("FPA") Section 206. In this Opinion, the FERC rejected using the Risk Premium and Expected Earnings approaches to estimating the ROE. FERC stated:

> 1. On November 15, 2018, the Commission issued an Order Directing Briefs in the above-captioned proceedings. The Briefing Order directed the participants in the above captioned proceedings to submit briefs regarding: (1) a proposed framework for determining whether an existing base return on equity (ROE) is unjust and unreasonable under the first prong of Federal Power Act (FPA) section 206; and (2) a revised methodology for determining just and reasonable base ROEs under the second prong of FPA section 206. As discussed below, we will adopt the proposal in the Briefing Order, with certain revisions. *Principally, we will not adopt the use of the expected earnings (Expected Earnings) and risk premium (Risk Premium) models in our ROE analyses under the first and second prongs of section 206, and instead will use only the discounted cash flow (DCF) model and capital-asset pricing model (CAPM) in our ROE analyses under both prongs of section 206.* (emphasis added)

<u>**Flotation Costs**</u>

Q. BEGINNING ON PAGE 34 OF HIS DIRECT TESTIMONY, MR. HEVERT PRESENTED HIS POSITION REGARDING THE NEED TO RECOGNIZE THE EFFECT OF FLOTATION COSTS IN THE COST OF EQUITY. PLEASE ADDRESS MR. HEVERT'S POSITION ON FLOTATION COSTS.

A. A flotation cost adjustment attempts to recognize and collect the costs of issuing common stock. Such costs typically include legal, accounting, and printing costs as well as broker fees and discounts. In my opinion, it is likely that flotation costs are already accounted for in current stock prices and that adding an adjustment for flotation costs amounts to double counting. A DCF model using current stock prices should already account for investor expectations regarding the collection of flotation costs. Multiplying the dividend yield by a 4% flotation cost adjustment, for example, essentially assumes that the current stock price is wrong and that it must be adjusted downward to increase the dividend yield and the resulting cost of equity. This is not an appropriate assumption regarding investor expectations. Current stock prices most likely already account for flotation costs, to the extent that such costs are even accounted for by investors.

Business Risks and Other Considerations

Q. BEGINNING ON PAGE 37 OF HIS DIRECT TESTIMONY, MR. HEVERT PROCEEDED TO DESCRIBE SEVERAL BUSINESS RISKS AND OTHER FACTORS THAT HE RECOMMENDED BE TAKEN INTO CONSIDERATION "WHEN DETERMINING WHERE DUKE PROGRESS' COST OF EQUITY FALLS WITHIN THE RANGE OF RESULTS." PLEASE RESPOND TO MR. HEVERT'S DISCUSSION OF THESE FACTORS AND WHETHER THEY SHOULD INFLUENCE THE COMMISSION'S DECISION REGARDING DUKE PROGRESS' RETURN ON EQUITY.

A. I found Mr. Hevert's discussion regarding the "additional factors" to be considered by the Commission a biased and one-sided view of the overall riskiness of Duke Progress. Instead, I recommend that the Commission consider my discussion of the Company's credit strengths and challenges in Section II of my testimony as enumerated by Moody's. The credit challenges enumerated by Moody's were supplemented by consideration of the Company's credit strengths, which support its current A2/A- credit rating. This credit rating is above average when compared to the EEI's average S&P credit rating for the electric utilities it follows of BBB+. Duke Progress' A2 credit rating is in the middle of the A rating category for Moody's and, if anything, suggests that the Commission should grant an ROE below the mean results of the proxy group. Overall, I suggest that the Commission look to Duke Progress' strong overall credit ratings as the indicator of the Company's riskiness compared to the proxy group. These credit ratings do not support an above average return on equity for the Company.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

I. QUALIFICATIONS AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Richard A. Baudino. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A. I am a consultant with Kennedy and Associates.

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

A. Yes, I filed Direct Testimony in these dockets on behalf of the North Carolina Attorney General's Office ("AGO").

Q. PLEASE SUMMARIZE YOUR SUPPLEMENTAL DIRECT TESTIMONY IN THIS PROCEEDING.

A. My Supplemental Direct Testimony will cover the following areas:

1. I will provide an update of the return on equity ("ROE") analyses for Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP")[1] that were contained in my Direct Testimonies in Docket Nos. E-2, Sub 1219 and E-7, Sub 1214.
2. I will provide an updated analysis of economic conditions in North Carolina.

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[1] I will refer to both DEC and DEP as "the Companies" later in my Supplemental Direct Testimony.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. Based on my updated ROE analyses, I continue to recommend a 9.0% ROE for DEC and DEP. Consistent with my Direct Testimonies, I continue to recommend that the Commission adopt a capital structure for both Companies that contains a 51.5% common equity ratio. In addition, in light of the shocks that have been delivered to the national and the North Carolina economies and the attendant skyrocketing unemployment of North Carolina's work force due to the COVID-19 pandemic, it is more important than ever that the North Carolina Utilities Commission ("NCUC" or "Commission") reject the Companies' requested 10.30% ROE. My 9.0% ROE recommendation is consistent with current investor required returns for low-risk regulated electric companies like DEC and DEP and supports just and reasonable rates for the Companies' North Carolina customers.

II. UPDATE OF THE DCF AND CAPM ANALYSES

Q. PLEASE SUMMARIZE THE IMPACTS ON THE FINANCIAL MARKETS DURING MARCH THROUGH JUNE OF THIS YEAR FROM THE COVID-19 PANDEMIC.

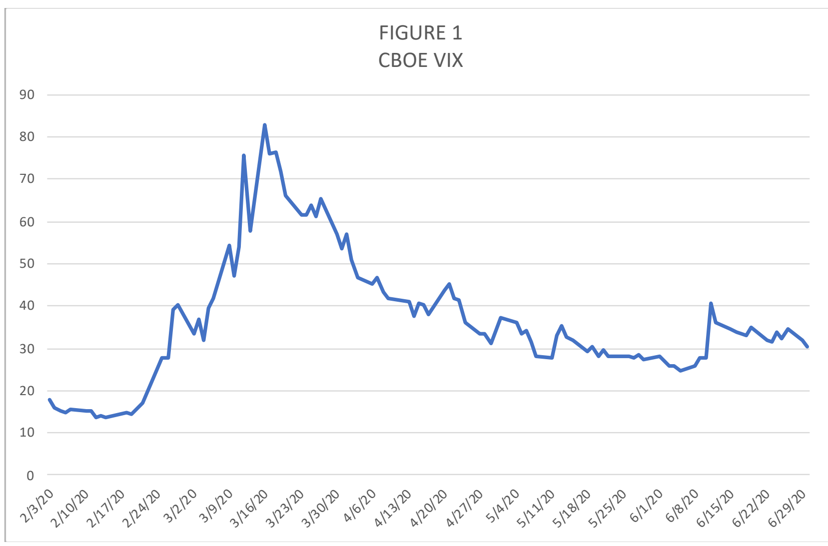
A. This section of my Supplemental Direct Testimony provides the Commission with an update of the interest rate and bond yield data since the beginning of March 2020, when concerns about the Covid-19 pandemic began to roil financial markets with extreme volatility.

As I mentioned in my Direct Testimony for DEP filed April 13, the yield on the 30-Year Treasury bond declined from 1.97% in February 2020 to 0.99% on March 9, increased to 1.63% on March 17, and ended March at 1.46%. The April ending yield on the 30-Year Treasury bond fell even further to 1.27%. As of June 30, 2020 the yield was 1.41%.

Alternatively, the yield on the average public utility bond increased dramatically in March, rising from 3.14% in February to 4.24% on March 18, according to Moody's Credit Trends. At the end of March, the average public utility bond yield fell to 3.59% according to the Mergent Bond Record. As of June 30, 2020 Moody’s Credit Trends reported that the yield on the average public utility bond was 3.05%, even lower than the March 2020 yield. The 3.05% yield is now significantly lower than the pre-pandemic January 2020 average utility bond yield of 3.34%.

In March, the stock market underwent a steep, sharp decline of approximately 19% due to the COVID-19 pandemic. Utilities also declined in March, with the Dow Jones utility average declining from 886.52 on March 2 to a March low of 695, a decline of about 21.6% with substantial volatility, or changes to the index's value, within the month. In April, however, the stock market and the Dow Jones utility index began to recover. After falling to a low in March of 695, the Dow Jones utility index recovered to finish April at 761.83, an increase of 9.6% from the March low. As of June 30, 2020, the Dow Jones Utility Index stood at 767.50, not much different from the end of April.

A widely used measure of market volatility is the Chicago Board Options Exchange ("CBOE") Volatility Index ("VIX"), also called the "fear index" or "fear gauge." Basically, the VIX measures the market's expectations for volatility over the next 30-day period. The higher the VIX, the greater the expectation of volatility and market risk. Figure 1 below presents the VIX from February 1 through June 30, 2020. Figure 1 shows that the VIX was much lower in February, shot up to a high of 82.69 on March 16, then generally declined through June, with the VIX at 30.43 on June 30, 2020.



Q. PLEASE SUMMARIZE RECENT FED ACTIONS WITH RESPECT TO MONETARY POLICY.

A. As I testified in my Direct Testimony filed April 13 in the DEP proceeding, on March 3 and 15, 2020, the Fed lowered the federal funds rate in response to mounting concerns associated with the spread of the coronavirus worldwide. On June 10, 2020, the Fed issued a press release that stated the following:

> The Federal Reserve is committed to using its full range of tools to support the U.S. economy in this challenging time, thereby promoting its maximum employment and price stability goals.
>
> The coronavirus outbreak is causing tremendous human and economic hardship across the United States and around the world. The virus and the measures taken to protect public health have induced sharp declines in economic activity and a surge in job losses. Weaker demand and significantly lower oil prices are holding down consumer price inflation. Financial conditions have improved, in part reflecting policy measures to support the economy and the flow of credit to U.S. households and businesses. The ongoing public health crisis will weigh heavily on economic activity, employment, and inflation in the near term, and poses considerable risks to the economic outlook over the medium term. In light of these developments, the Committee decided to maintain the target range for the federal funds rate at 0 to 1/4 percent. The Committee expects to maintain this target range until it is confident that the economy has weathered recent events and is on track to achieve its maximum employment and price stability goals.
>
> The Committee will continue to monitor the implications of incoming information for the economic outlook, including information related to public health, as well as global developments and muted inflation pressures, and will use its tools and act as appropriate to support the economy.

Beginning in March 2020, the Federal Reserve also announced expanded actions to support credit and financial markets. The Board of Governors of the Federal Reserve System established a new resource on its web site that contains the Fed's ongoing response to the Covid-19 pandemic: https://www.federalreserve.gov/covid-19.htm. Some of the major actions undertaken by the Fed include the following:

- Creation of the Municipal Liquidity Facility to assist state and local governments manage cash flow to better serve households and businesses (April 9, 2020).

- Creation of the Main Street Lending Program to support small and medium sized businesses. There are three facilities that comprise this program: the Main Street New Loan Facility, the Main Street Priority Loan Facility, and the Main Street Expanded Loan Facility.
- Design of the Commercial Paper Funding Facility to support the flow of credit to households and businesses (March 17, 2020).
- Establishment of the Primary Dealer Credit Facility designed to support households and businesses (March 17, 2020).
- Establishment of the Money Market Mutual Fund Liquidity Facility as another program to facilitate the flow of credit to households and businesses (March 18, 2020).
- Establishment of the Primary and Secondary Corporate Credit Facilities that support credit to employers (March 23, 2020).
- Implementation of the Paycheck Protection Program Liquidity Facility to support the Small Business Administration's Paycheck Protection Program (April 9, 2020).
- Establishment of the Term Asset-Backed Securities Loan Facility ("TALF"), again to support the flow of credit to consumers and businesses (March 23, 2020).[2]

[2] For more information on the Fed's response to Covid-19, please see https://www.federalreserve.gov/funding-credit-liquidity-and-loan-facilities.htm

Q. PLEASE UPDATE THE COMMENTS FROM VALUE LINE'S REPORTS ON THE ELECTRIC UTILITY INDUSTRY THAT WERE PUBLISHED SINCE YOUR DIRECT TESTIMONY WAS FILED.

A. In its June 12, 2020 report on the Electric Utility (Central) Industry, Value Line noted the following:

> Electric utility stocks, as a group, have outperformed the broader market averages in 2020. There has been a wider-than-usual disparity in the performances of individual stocks. Electric company equities have exhibited more volatility than usual, too.

The Value Line report also noted that perhaps the "economic problems will result in a lower rate of dividend growth, but we do not expect the boards of any companies reviewed here to cut the disbursement."

Value Line also noted the following in its May 15, 2020 report on the Electric Utility (East) Industry:

> Utility stocks are seen as a safe (more accurately, less-risky) haven when the markets are turbulent. Most of the equities in this group have declined far less than the broader market averages since the market plummeted in late February. However, the volatility these issues have exhibited has belied their high Price Stability Indexes. The quotations of most stocks in the Electric Utility Industry have fallen between 10% and 20% so far this year. The average dividend yield for this group is 3.8%.

My conclusion from this discussion is that regulated electric utilities like DEC and DEP continue to be safe, conservative, and relatively stable investments even in the currently volatile financial market.

Q. WHAT ARE THE CURRENT CREDIT RATINGS FOR DUKE ENERGY PROGRESS AND DUKE ENERGY CAROLINAS?

A. The credit ratings for DEC and DEP have not changed since I filed my Direct Testimony. DEC has an A1 rating from Moody's and an A- rating from Standard and Poor's ("S&P"). DEP has an A2 credit rating from Moody's and an A- rating from S&P. These ratings all have stable outlooks.

Q. PLEASE PRESENT YOUR UPDATED ROE CALCULATIONS.

A. Supplemental Exhibits RAB-1 through RAB-4 present my updated ROE calculations. Supplemental Exhibit RAB-1 contains updated dividend yields for the companies in the Proxy Group that Companies witness Dylan D'Ascendis used in his Rebuttal Testimony. This is the same proxy group I used in my Direct Testimony, with the addition of Avista Corporation, a company that now meets Mr. D'Ascendis' criteria for inclusion. Stock prices were updated for the six-month period of January through June, 2020.

Supplemental Exhibit RAB-2 contains updated growth forecasts from the Value Line Investment Survey, Zacks, and Yahoo! Finance. This exhibit also contains updated ROE estimates using the Discounted Cash Flow ("DCF") method.

Supplemental Exhibits RAB-3 and RAB-4 present updated calculations for the Capital Asset Pricing Model ("CAPM"). Supplemental Direct Table 1 below provides a summary of the updated ROE results.

Supplemental Direct Table 1
SUMMARY OF ROE ESTIMATES

DCF Methodology	
Average Growth Rates	
- High	8.98%
- Low	8.29%
- Average	8.75%
Median Growth Rates:	
- High	9.28%
- Low	8.41%
- Average	8.88%
CAPM Methodology	
Forward-lookng Market Return:	
- Current 30-Year Treasury	9.25%
- D&P Normalized Risk-free Rate	9.61%
Historical Risk Premium:	
- Current 30-Year Treasury	6.19% - 6.98%
- D&P Normalized Risk-free Rate	7.56% - 8.35%

Q. PLEASE DISCUSS THE DIFFERENCES IN THE RESULTS FROM THE ANALYSES IN YOUR DIRECT TESTIMONY.

A. With respect to the DCF results, the updated six-month dividend yield increased to 3.32% from 2.88%. However, the average and median growth rates for Zacks, Yahoo! Finance, and Value Line declined. The resulting updated DCF ROEs increased slightly from those in my Direct Testimony, from 8.60% - 8.67% to 8.75% - 8.88%.

The CAPM results increased significantly due to a very large increase in the Value Line average beta value, from 0.56 in my Direct Testimony to 0.74 in the update. This represents an increase of 32.1% in the average beta for the proxy group. Indeed, my updated results for the forward-looking CAPM increased markedly to 9.25% - 9.61%. My updated results for the historical CAPM also increased significantly to 6.19% - 8.14%.

Q. BASED ON YOUR UPDATED ROE CALCULATIONS, WHAT IS YOUR ROE RECOMMENDATION IN THIS CASE?

A. I continue to recommend that the Commission adopt a 9.0% ROE for the Companies. Although the DCF results increased in the update, they did not increase enough to suggest a higher required ROE on the part of investors for low-risk regulated electric utility investments like DEC and DEP. Further, the stability of the Companies' current credit ratings do not suggest that the required ROE increased since I filed my Direct Testimonies. Likewise, although the CAPM results also increased, the range of both historical and forecasted ROE results continue to support 9.0% as just and reasonable.

Q. DOES THE TREND IN BOND YIELDS, BOTH FOR THE 30-YEAR TREASURY BOND AND AVERAGE UTILITY BONDS, SUGGEST AN INCREASE IN THE REQUIRED ROE FOR DEC AND DEP?

A. No. June 2020 yields were lower than they were in January 2020 for both the 30-Year Treasury Bond and for bonds of regulated utilities. This decline in bond yields does not support higher ROEs for the Companies.

Q. IS A SIX-MONTH PERIOD STILL APPROPRIATE FOR CALCULATING THE DIVIDEND YIELD FOR THE PROXY GROUP?

A. Yes. The updated six-month period of January through June 2020 is weighted more toward the more volatile period of the pandemic (March through June). Supplemental Exhibit RAB-1 shows that the monthly dividend yield for the proxy group increased significantly in March through May, then declined from May to June. March through June dividend yields are all much higher than

January and February. Given the volatility present in financial markets, I believe it is still advisable to include the more stable months of January and February in the average dividend yield calculation for the proxy group.

Q. YOU MENTIONED THAT THE CAPM RESULTS INCREASED SINCE YOU FILED YOUR DIRECT TESTIMONY AND THAT A LARGE INCREASE IN AVERAGE BETA FOR THE PROXY GROUP WAS RESPONSIBLE. PLEASE ADDRESS WHETHER THE COMMISSION SHOULD INCLUDE THE HIGHER CAPM RESULTS IN ITS CONSIDERATION OF THE ALLOWED ROE FOR DEC AND DEP IN THIS CASE.

A. I continue to recommend that the Commission rely on the DCF model for its ROE determination in this case. In my view, the sharp increase in betas for the companies in the proxy group was influenced by the extreme market volatility due to the Covid-19 pandemic. It is likely the increases in beta were due to greater volatility in the stock prices for regulated electric utilities relative to the movement of the market in general since the last Value Line reports that I relied on in my Direct Testimony. The question now is whether investors believe that regulated electric utilities are more risky relative to the general market than they were before the volatile period since March 2020. I believe the sharp increase in betas could be a short-term phenomenon and, as such, I would not advise placing much reliance on the CAPM results at this time. Certainly, the DCF results do not suggest a sharp increase in investor required ROEs for regulated electric companies.

The increase in the average beta factor for the proxy group underscores the shortcomings of the CAPM that I described in detail in my Direct Testimony in the DEP case. I point to pages 29 - 30 of my Direct Testimony where the problems with beta were set forth. The recent increase in the average beta for the proxy group is not consistent with the decline in average utility bond yields from January to June 2020. Also, given the decline in the Volatility Index (the "VIX" that I presented earlier), I believe it is highly unlikely that a 32% increase in expected betas for electric utilities since earlier in the year is accurate and reliable. In conclusion, the CAPM results should be viewed with even more caution and skepticism than when I filed my Direct Testimony in this proceeding.

Q. ARE YOU AWARE OF A RECENT ROE AWARD THAT WAS GRANTED TO DUKE ENERGY KENTUCKY BY THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. Yes, I am aware of this Order, as I was involved in this case on behalf of the Attorney General of the Commonwealth of Kentucky. In its Order in Case No. 2019-00271 dated April 27, 2020 the Kentucky Public Service Commission ("KPSC") authorized an allowed ROE for Duke Energy Kentucky ("DEK") of 9.25%. The KPSC also authorized a common equity ratio of 48.23%. Further, the KPSC denied DEK's request for rehearing on the ROE issue in an Order dated June 4, 2020. In terms of credit ratings, DEK has a Moody's rating of Baa1 with a stable outlook and a S&P rating of A- with a stable outlook. These credit ratings are fairly similar to those of DEC and DEP. In fact, the Companies have slightly higher Moody's credit ratings (A2 and A1 for DEP and DEC, respectively). My recommendation of a 9.0% ROE with a 51.50% common equity ratio compares favorably with the KPSC Order for DEK.

I would like to add that I'm also aware that the KPSC made its ROE determination based on data that preceeded the Covid-19 pandemic and the associated market volatility that I described earlier in this testimony. However, my updated DCF analyses show the investor required return for regulated electric companies did not change significantly since I filed my Direct Testimony in the DEP case on April 13. I'm also aware that the NCUC will base its ROE decision in this case on the evidence presented to it and not on the ROE awards from other state commissions. Nevertheless, I wanted to provide this additional recent information from the KPSC Order for the Commission's consideration.

II. ECONOMIC CONDITIONS IN NORTH CAROLINA

Q. PLEASE SUMMARIZE THE CHANGES IN ECONOMIC CONDITIONS SINCE YOU FILED YOUR DIRECT TESTIMONY FOR DEC AND DEP.

A. The Covid-19 pandemic and the economic shutdowns that accompanied it, including that in North Carolina, caused an unprecedented economic contraction and skyrocketing unemployment. According to the U.S. Bureau of Labor Statistics, the unemployment rate for the United States rose from 3.5% in February 2020 to a high of 14.7% in April 2020. The unemployment rate for May 2020 was 13.3% and declined further in June 2020 to 11.1%. For North

Carolina, the unemployment rate rose from 3.6 in February 2020 to 12.9% in May the same as the rate for April.[3]

Nationally, real Gross Domestic Product ("GDP") declined in the first quarter of 2020 by -5.0%, according to the Bureau of Economic Analysis ("BEA").[4] The BEA also reported that profits from current production (corporate profits with inventory valuation and capital consumption adjustments) decreased $262.8 billion in the first quarter, in contrast to an increase of $53.0 billion in the fourth quarter of 2019.

Q. HOW DO THESE CHANGED ECONOMIC CONDITIONS AFFECT YOUR ROE RECOMMENDATION IN THESE PROCEEDINGS?

A. The ongoing Covid-19 pandemic continues to significantly affect economic activity, as well as the employment and incomes of North Carolinians. As I stated in my Direct Testimony on page 48, it is more important than ever for the Commission to consider the impacts of the Companies' requested ROE of 10.3% - 10.5% on North Carolina ratepayers. The Companies' ratepayers simply cannot afford to be saddled with an excessive ROE in this range. Based on current economic conditions and on my updated analyses, I continue to recommend that the Commission authorize the Companies a ROE of 9.0%.

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3 The May 2020 unemployment rate for North Carolina is preliminary. Data from *North Carolina Labor Market Conditions, May 2020*, North Carolina Department of Commerce. The June 2020 North Carolina unemployment rate was not available at the time I prepared my Supplemental Direct Testimony.

4 https://www.bea.gov/news/2020/gross-domestic-product-1st-quarter-2020-third-estimate-corporate-profits-1st-quarter-2020.

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL DIRECT TESTIMONY?

A. Yes.

MS. TOWNSEND: Yes. Yes, Commissioner Clodfelter. At this time, the Attorney General's Office calls Steven Hart to our Webex.

THE WITNESS: I'm here.

COMMISSIONER CLODFELTER: Mr. Hart. There you are.

Whereupon,

STEVEN C. HART,

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

COMMISSIONER CLODFELTER: Thank you. Ms. Townsend?

MS. TOWNSEND: Thank you.

DIRECT EXAMINATION BY MS. TOWNSEND:

Q. Would you please state your name and address for the record?

A. My name is Steven with a V, Hart. And business address is 2923 South Tryon Street, Suite 100, in Charlotte, North Carolina.

Q. Okay. And will you please state with whom you are employed and in what capacity?

A. I'm employed by Hart & Hickman, and I am the president and principal hydrogeologist.

Q. Okay. Did you cause to be prefiled in this case on April 13, 2020, direct testimony consisting of 175 pages and 80 exhibits numbered 1 through 24, 24A and B, 25 through 41, 42A through 50A, 42B through 50B, 42C, and 51 through 68?

A. Yes.

Q. Okay. And were pages 76, 77, 81 through 84, and 89 and 90 of your testimony originally designated as confidential?

A. Yes.

Q. Were pages 80 through 84 subsequently released from the confidential designation by Duke?

A. Yes.

Q. Were Exhibits 31, 32, 38, and 39 originally designated as confidential?

A. Yes.

Q. And were exhibits 38 and 39 subsequently released from the confidential designation by Duke?

A. Yes.

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

A. Yes.

Q. Have you prepared an errata sheet and a revised errata sheet with those changes?

A. Yes, I have.

Q. Okay. With those corrections, if I were to ask you the same questions today, would your answers be the same?

A. Yes.

Q. And, Mr. Hart, have you done a summary of your testimony?

A. Yes, I have.

Q. And that summary was sent to all of the parties in this case.

MS. TOWNSEND: Commissioner Clodfelter, I would request that Mr. Hart's direct testimony, both public and confidential, the errata sheet and the revised errata sheet regarding same, as well as summary be copied into the record as if given orally from the stand, and that his 80 exhibits be identified and marked. I believe you're on mute, Commissioner.

COMMISSIONER CLODFELTER: Again, you heard the motion from Ms. Townsend. Are there any objections to the motion?

(No response.)

COMMISSIONER CLODFELTER: All right. Mr. Mehta, will you simply confirm for the record that the confidential designations and the releases as recounted by Ms. Townsend in the motion are correct?

MR. MEHTA: They are correct, Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Thank you. Hearing no objection to the motion, then, it will be granted.

MS. TOWNSEND: Thank you.

(Hart Exhibits 1 through 24, 24A and B, 25 through 30, 33 through 41, 42A through 50A, 42B through 50B, 42C, and 51 through 68; and Hart Confidential Exhibits 31 and 32 were identified as they were marked when prefiled.)

(Whereupon, the prefiled direct testimony, errata, revised errata, and summary of Steven C. Hart were copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1219

In the Matter of	)	PUBLIC
	)	DIRECT TESTIMONY OF
Application of Duke Energy Progress, LLC	)	STEVEN HART
For Adjustment of Rates and Charges Applicable	)	ON BEHALF OF
to Electric Service in North Carolina	)	ATTORNEY GENERAL'S
	)	OFFICE

I. INTRODUCTION

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

A. My name is Steven Hart and I am the President and Principal Hydrogeologist of the environmental consulting and engineering firm Hart & Hickman, PC. Hart & Hickman, PC started its business in 1995, has offices in Charlotte and Raleigh, North Carolina, and employs over 60 professionals. My business address is 2923 South Tryon Street, Suite 100, Charlotte, NC.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Arts degree with Honors in 1986 (member Phi Beta Kappa) from the University of Virginia in Environmental Science with an emphasis in hydrology (the study of surface and subsurface water) and hydrogeology (the study of the occurrence and movement of subsurface water). I received a Master of Science degree in 1989 from Texas A&M University in Geology, specializing in the areas of engineering geology (the study of the impact of geology on engineering structures such as dams) and hydrogeology. I have attended continuing professional education seminars on topics concerning geology, hydrogeology, the fate and transport of contaminants in the environment, site assessment and remediation, and other environmental science principles. I use the term "fate and transport" in my testimony to describe the overall concept of 1) how a contaminant moves in soil, sediment, surface water, and groundwater (i.e., the transport component), and 2) how the contaminant may change once it enters the environment (i.e., the fate component).

Prior to founding H&H, I was employed by the international environmental and engineering consulting firms Environmental Resources Management and Dames & Moore (now AECOM) in Charlotte. I have over 30 years of hands-on experience assessing geologic and hydrogeologic conditions and managing and remediating environmental impacts at sites throughout the United States and in particular in North Carolina and South Carolina. In my professional experience, I have been engaged in all facets of environmental investigation and remediation for various types of compounds including metals and other inorganic compounds, petroleum hydrocarbons, chlorinated hydrocarbons, volatile and semi-volatile organic compounds, pesticides, herbicides, and per- and polyfluoroalkyl substances (PFAS) in soil, sediment, groundwater, and surface water. I have also been directly involved in soil and groundwater remediation design and implementation at a wide variety of sites, and have implemented remedial programs which have utilized such methods as soil (and other solids) removal and treatment, groundwater extraction and treatment, soil vapor extraction, bio-venting, air sparging, in-situ chemical oxidation, enhanced bio-remediation, and natural attenuation. I frequently consult clients on regulatory compliance issues and protection of human health and the environment with regard to soil, sediment, surface water, and groundwater contamination.

Q. WHAT PROFESSIONAL LICENSES AND REGISTRATIONS DO YOU HOLD?

A. I am a Licensed Geologist (LG) or Professional Geologist (PG) in the States of North Carolina, Alabama, Arkansas, Georgia, South Carolina, Tennessee, Texas, Washington, and Wisconsin. I first received professional registration by exam in North Carolina in 1989. In addition, I am a Registered Site Manager (RSM) under the North Carolina Department of Environmental Quality (DEQ) Inactive Hazardous Sites Branch (IHSB) Registered Environmental Consultant (REC) Program. This program was established in 1997 due to limited DEQ resources to address contaminated sites, and it is essentially a privatized regulatory oversight program. In this program a remediating party can hire a REC such as my company Hart & Hickman, PC to perform assessment and remedial actions at a site with limited DEQ oversight, and the RSM certifies that the actions have been performed in accordance with DEQ rules and guidance and to protect human health and the environment.

Q. HAVE YOU BEEN QUALIFIED AS AN EXPERT AND TESTIFIED IN STATE AND FEDERAL COURTS?

A. Yes, I have testified multiple times in State and/or Federal courts in North Carolina, South Carolina, and Arkansas. I have been qualified as an expert in the areas of geology, hydrogeology, fate and transport of contaminants in the environment, contaminant source identification, site assessment and remediation, exposure potential, adequacy of response actions, and remedial methods and costs.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Duke Energy Progress (DEP) is seeking recovery of costs in its rates for addressing coal combustion residuals (CCRs), principally related to coal ash basin closure and associated groundwater contamination at eight DEP facilities (Asheville, Cape Fear, HF Lee, Mayo, Robinson, Roxboro, Sutton, and Weatherspoon). All of these facilities are located in North Carolina except for the Robinson plant which is located in South Carolina. As described in Section IV below, one or more coal ash basins were used at each of the DEP facilities for management of CCRs. The CCRs were transported via water (called "sluicing") from the coal-fired power plants to unlined basins where the CCRs were allowed to settle and accumulate over time, and the resultant water was discharged to surface water bodies (lakes or rivers), infiltrated into groundwater, and evaporated. In addition, multiple other aqueous waste streams from the coal-fired power plants were placed in the coal ash basins such as cleaning wastewaters and air pollution control wastewaters.

My testimony focuses primarily on answering the following questions based upon my experience managing environmental contamination in North and South Carolina for over 30 years: First, given the information that DEP knew or that was reasonably discoverable to DEP prior to the adoption of specific regulatory requirements in North Carolina's Coal Ash Management Act (CAMA) and the Environmental Protection Agency's (EPA's) CCR regulations, did DEP undertake reasonable and prudent actions and practices in a timely manner to address storage and disposal of CCR and closure of its coal ash basins before the Dan River release occurred in 2014? Second, how would costs that DEP is seeking for coal ash-related activities likely be different today if DEP had initiated actions sooner to address its ash basin practices?

Please note the following with regard to my testimony:

- Carolina Power & Light (CP&L) and Progress Energy are predecessor names to Duke Energy Progress (DEP). For ease of reference, throughout this testimony, I refer to CP&L and Progress Energy as "DEP" although they were not technically DEP before July 2012.
- The terms coal ash and CCR are used interchangeably,
- The terms coal ash basin, coal ash pond, and coal ash impoundment are used interchangeably.

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

A. In preparing my testimony, I reviewed the following information:

- I reviewed the parts of DEP's 2019 Rate Case application and testimony relating to coal ash.
- I was provided access to the Merrill Data site, an online document portal for the DEP 2019 Rate Case, and reviewed data requests related to coal ash basins from the North Carolina Utilities Commission Public Staff, NC Attorney General's Office and other intervenors, and the associated DEP responses to those data requests.

- I was provided access to the Consilio/Relativity online database and performed queries and reviewed various documents in that document portal.
- I reviewed documents provided by the North Carolina Attorney General's Office.
- I reviewed documents available on the North Carolina Department of Environmental Quality's (DEQ's) online document portal called Laserfiche.
- I reviewed documents obtained from DEQ's website regarding coal ash at the DEP facilities.
- I reviewed documents obtained from Duke Energy's website concerning coal ash.
- I reviewed regulatory and industry publications related to CCRs and coal ash basins.
- I attempted to review documents obtained through file review requests to the North Carolina Department of Environmental Quality (DEQ) and the South Carolina Department of Health and Environmental Control (DHEC). However, because a portion of the work associated with this project was performed during the COVID-19 pandemic, both agencies indicated that they could not fulfill the file review requests within the timeframe when this pre-filed testimony was completed.

I recognize that there is a very large volume of documents from these sources regarding CCR and coal ash basins at the DEP facilities. In my review and evaluation, I strived to be thorough but recognize that it is possible that I did not locate some documents that could potentially be relevant to my testimony. However, given the large volume of documents I reviewed, it is unlikely that such additional information would significantly affect my testimony.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I have organized my testimony into sections as follows:

- Section II provides a summary of my testimony which is further described in Sections III through XIII.
- Section III briefly describes rules governing coal ash basins and specifically groundwater contamination from coal ash basins.
- Section IV provides a general history of information about coal ash basins and groundwater contamination.
- Sections V through XII describe specific information about coal ash basins and groundwater contamination at each of the eight DEP facilities.
- Section XIII answers the questions that are the purpose of my testimony based upon an evaluation of the information in Sections II through XII.

II. SUMMARY OF FACTS AND OPINIONS

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. My testimony will show the following facts and opinions based on my expert analysis:

- The knowledge base concerning the impact to groundwater from unlined coal ash basins increased over time from the 1980s to the mid-2000s.
- The utility industry, including DEP, knew about the reasonable potential for contamination of groundwater from coal ash basins as early as the 1980s.
- By the late 1980s, as a result of groundwater contamination concerns at the Sutton facility, DEP was aware that 1) DEQ had significant concerns about the presence of groundwater contamination from coal ash basins, 2) a clay bottom liner installed in a new ash basin by DEP was a potential method to minimize the potential for groundwater impacts, 3) if concentrations of compounds in groundwater were elevated from a coal ash pond but did not exceed the groundwater standards, they were still of concern to DEQ and needed to be evaluated further, and 4) groundwater impacts at and beyond the compliance boundary from coal ash basins did occur.
- At the DEP Robinson, Roxboro, and Weatherspoon facilities, groundwater monitoring had been conducted as early as the early to mid-1990s and indicated groundwater contamination issues with coal ash disposal areas.
- By the early 1990s DEP knew that, by modifying coal ash facilities, it could decrease metals concentrations in water and protect the environment. Discharge of selenium from the coal ash basins at the Roxboro facility affected fish reproduction causing a decline in fish populations in Hyco Lake in the 1970s and 1980s, and resulting in estimated damages of $877 million. North Carolina issued a fish consumption advisory for Hyco Lake in 1988. In approximately 1990, DEP installed a dry ash handling system to

meet new permit limits for selenium, which improved water quality and resulted in a complete rescission of the fish advisory in 2001. Nonetheless, when groundwater impacts were identified in the area of the coal ash basins, similar responsive remedial actions could have been taken but were not.

- By the early 2000s, as a result of an EPA Regulatory Determination, it was clear to the electric utility industry that EPA's documentation of damage cases from coal ash basins and their assessments of environmental impact would lead to increased scrutiny, environmental sampling, and potential closure of ash basins.
- In 2006 through 2008, DEP implemented voluntary groundwater monitoring at its ash basins as part of the Utility Solid Waste Activities Group (USWAG) effort to address EPA's concern about groundwater impacts from coal ash basins. The USWAG action plan was the electric utility industry's <u>commitment</u> to adopt groundwater performance standards at facilities that manage CCRs and to implement a comprehensive monitoring program to measure conformance with the groundwater standards at facilities that managed CCRs. The utility industry offered the USWAG action plan as an alternative to mandatory federal requirements because the utility industry committed to work within existing state regulatory programs to address groundwater impacts and to protect human health and the environment. Yet, even after the groundwater data were collected which irrefutably indicated groundwater impacts associated with the coal ash basins, DEP did not follow the USWAG action plan about how

to respond to groundwater data collection where groundwater impacts were detected. The USWAG action plan indicates that, on detecting groundwater impacts, DEP should have worked with the regulatory agency to further assess conditions and, as needed, develop corrective action programs. Instead, DEP submitted the data to DEQ without evaluation or responsive action.

- In 2010, EPA proposed rules to regulate CCRs at electric generating plants. In the proposed rule, EPA included two options for public consideration to manage CCRs in landfills and impoundments: one in which CCRs would be managed as a hazardous waste under RCRA subtitle C and the other in which CCRs would be managed as non-hazardous waste under RCRA subtitle D.
- In 2015, EPA issued its final CCR rule which indicated that CCRs disposed in landfills and ash basins would continue to be managed as non-hazardous wastes, and the rules also established national minimum criteria for existing and new CCR surface impoundments including location restrictions, design and operating criteria, groundwater monitoring and corrective action, and closure requirements and post closure care.
- Before the EPA's final rule was issued, however, between 30,000 to 39,000 tons of coal ash and 27 million gallons of coal ash basin water were released into the Dan River from the Duke Energy Carolinas (DEC) Dan River facility in February 2014, and as a result, North Carolina issued its own Coal Ash Management Act (CAMA). CAMA included a procedure for

prioritization of coal ash basin closures, requirements to convert facilities to dry ash handling by certain dates (to eliminate the need for sluicing to ponds), accelerated timeframes for performing receptor surveys, and accelerated timeframes for groundwater assessment plans and corrective action plans.

- Although there was some uncertainty about how coal ash ponds would be managed prior to the enactment of CAMA and the promulgation of federal CCR rules, there was no ambiguity about the requirements of North Carolina's groundwater corrective action rules. (Title 15A NCAC Subchapter 2L, as referred to herein as the 2L Rules). When groundwater contamination is detected in association with a permitted ash pond – i.e., .if a 2L Standard for a compound is exceeded -- the 2L Rules require that the responsible party determine the nature and extent of the contamination, terminate and control the discharge, mitigate hazards, perform receptor surveys to identify potential receptors of the contamination, and propose and implement corrective actions.
- This lack of ambiguity ab[out requirements of the 2L Rules is confirmed by DEP's statements to its insurance carriers in 2011 which advised that, regardless of when EPA may act or what other states may do, 1) North Carolina is taking aggressive action on coal ash facilities, 2) there are existing regulations (i.e., the North Carolina 2L Rules for groundwater) that describe the corrective action process if there are exceedances at the

compliance boundaries, and 3) North Carolina regulations already provide for the same potential closure scheme as EPA's proposed rules.

- The detections above 2L Standards within or beyond the compliance boundary or in the bedrock aquifer at North Carolina DEP facilities should have triggered additional actions such as installation of wells at the compliance boundary, installation of additional monitoring wells to define the extent of impacts, and implementation of corrective actions, as warranted. However, rather than responding proactively to groundwater contamination at its coal ash basins, DEP chose to wait until regulatory agencies noted groundwater contamination concerns from DEP's data submittals. Similarly, in South Carolina, detections above the maximum contaminant levels (MCLs) at the South Carolina DEP facility should have triggered additional assessment and, if warranted, corrective action.
- Even after wells were installed along compliance boundaries at DEQ's direction in 2010 at all of the DEP North Carolina facilities, DEP continued to indicate as late as 2013 that it strongly believed that the iron and manganese exceedances were the result of background concentrations and that these compounds only had secondary MCLs. However, there are several flaws with DEP's conclusions. First, secondary MCLs are not the standard for groundwater in North Carolina and are no defense to an exceedance to the 2L Standard. Second, in almost all cases the exceedances were, in fact, significant. Third, in almost all cases, actual data from the facilities were irrefutable that the groundwater impacts above 2L Standards

were not solely from background conditions.

- In addition to sluicing coal ash, over time DEP discharged other wastewater streams to the basins, and it did so in some cases without evidence of how those additional waste streams, such as advanced air pollution control technology wastewaters and sandblast material, would impact the basins and groundwater. In fact, there is evidence that the addition of FGD wastewaters led to increased groundwater contamination from the basins and that DEP was aware of these issues. However, DEP did not address the increased contamination to minimize the impact to groundwater or bring the condition to the attention of DEQ.
- At the DEP Asheville, Cape Fear, HF Lee, Roxboro, and Sutton facilities, one or more coal ash basins were taken out of service or only used for very limited purposes starting in the 1960s through the 1980s because they were functionally full; however, there were no efforts to close the ponds. In fact, many of the basins continued to receive stormwater discharge even after they were functionally full which maintained the hydraulic head on the basins, thus continuing to contribute to groundwater impacts.
- In 2013 and 2014, Duke Energy documents acknowledged that DEP did not yet have any approved closure plans and that it had failed to make "reasonable efforts" toward the closure of unclosed basins.
- Other industries in North Carolina with similar types of permitted disposal facilities were actively addressing groundwater impacts with DEQ and

implementing corrective action to address the sources of groundwater contamination in the 1970s to 1990s.

- It was not until after the Dan River release in February 2014, and the resulting pressure to address concerns from the public and regulators, that DEP committed to implement full assessments, closure evaluations, some dry ash handling conversions, and closure activities on an expedited basis.
- It is evident from my analysis that, as a result of groundwater monitoring data at its coal ash basins and increased internal concern with groundwater contamination from coal ash basins, DEP should have taken responsive action sooner and initiated a systematic plan to address its coal ash basins by 1) closing long out of use basins and, for basins still receiving CCRs, 2) converting facilities to dry ash handling, 3) eliminating other wastewater streams, 4) engaging in closure planning, and 5) evaluating methods to reduce environmental impact while the basins were still operational.
- DEP's costs are higher today than they would have been had DEP undertaken reasonable and prudent actions and practices in a timely manner to address storage and disposal of CCR and closure of its coal ash basins before the Dan River spill occurred in 2014. Among other factors, the accelerated timeframes for action and the requirements for higher cost approaches such as beneficiation and connection of all properties with water supply wells within a 0.5 mile radius of the compliance boundaries to alternate water supply were likely prompted after the Dan River spill, DEP's admission to criminal negligence at its Cape Fear, HF Lee and Asheville

plants, and an over $25 million fine assessed by DEQ for violations such as not addressing groundwater impacts, including potential impacts to off-site water supply wells, at its Sutton facility.

- Addressing out of use coal ash basins and groundwater impacts from coal ash basins would have required expenditure of funds earlier, but would have reduced long term risks and liabilities which would have certainly led to lower costs being requested by DEP and less significant groundwater impacts at this time. DEP's inattention to problems and delay in responsive actions increased the cost today:
  - DEP's actions and failure to take actions before the Dan River spill prompted the adoption of environmental requirements that imposed accelerated schedules to address coal ash basin problems, particularly at the Asheville and Sutton facilities, and costs for accelerated actions are almost always greater than costs under non-accelerated timeframes.
  - Further, DEP's admission that it was criminally negligent in how it managed some sites likely prompted a lack of confidence by regulators and the public that less costly actions would be effective, and prompted requirements that DEP take more extensive and high-cost approaches, such as the high-cost beneficiation requirement.
  - Most of the expenditures that DEP seeks to recover for coal ash basin closures and CCR disposal were incurred at coal plants that are retired and have not been used for several years to produce

  power for ratepayers. In fact, the only DEP coal fired facilities that were still in operation at the time of the Dan River spill in 2014 were the Asheville, Mayo, and Roxboro facilities.

  - Furthermore, substantial parts of the expenditures were incurred to close ash basins that have not been in substantial use for decades.
  - By engaging in reasonable monitoring and taking adequate responsive actions, some of the costs would have been included in the cost of service for customers while the coal plants and ash ponds were in use.
  - DEP's costs are higher today due to inflation.

- The requirement that Duke connect all households to alternate water supplies was likely a result of DEP's delay in addressing groundwater impacts. Prior to the Dan River release, DEP maintained that drinking water wells were not affected, but it is unheard of for a company to have to connect properties to alternate water when those water supplies are not impacted. In my opinion, this requirement that DEP provide permanent water supplies was warranted by law because DEP, once it knew it had groundwater issues, had failed to determine the extent of groundwater impacts, reliably establish background concentrations, and perform adequate receptor evaluations. Instead, DEP contended that there were few if any water supply well receptors in the area of its facilities and maintained that position despite there being no indication that it performed comprehensive receptor surveys until required to do so under CAMA. Thus, it appears that these costs were directly related to DEP's delay in evaluating groundwater impacts. Therefore, the $3,481,096 requested by DEP related to connection to alternate water supplies should not be included in the recoverable costs.

- To estimate reductions in closure costs related to DEP's delay in addressing its closed basins and groundwater impacts from coal ash basins, I took a stepwise approach as described below:

A. In Step A. I removed the alternate water connection costs for all of the facilities for the reasons discussed in the preceding paragraph which total $3,481,096.

B. In Step B, I evaluated each facility individually and excluded costs for those basins that were taken out of service long ago but had not been closed previously. There are five facilities where this occurred: Asheville, Cape Fear, HF Lee, Roxboro, and Sutton facilities. It is reasonable to conclude that today's ratepayers should not have to pay for closure of coal ash basins that were essentially out of use and functionally full in the 1960s to 1980s for which they derived no significant benefit and which continued to contribute to groundwater impacts after they were essentially out of use. For facilities that have closure planning costs associated with a long out-of-service basin and a more recently used basin, I used the ratio of ash placed in the long out-of-service basin(s) to the total ash to be removed to determine the excluded costs. For the Sutton facility, in which DEP's requested costs include those for actual ash removal from one or more ash management units, and where there was a long history of groundwater impacts outside the compliance boundary, I used the ratio of actual removed ash volumes for the long-out-of-substantial-use basin and "Lay of Land" area to the total removed ash volume for the facility. This Step B resulted in an additional excluded cost amount of $196,579,595. Combining Steps A and B results in excluded costs of $200,060,692, and non-excluded costs of $215,876,818.

C. In Step C, I estimated the reduction in the non-excluded costs of approximately $216 million if DEP had responded earlier to the presence of groundwater impacts at its coal ash basins. To do this, I assumed that the activities for which DEP is requesting cost recovery at this time are similar to the activities that would have been conducted at an earlier time and then considered the time value of money between the time when DEP knew it had issues with groundwater contamination and when it started planning for basin closure at most facilities in 2014/2015. Because there is evidence that 1) DEP was aware of the issues with groundwater contamination at its ash basins by the early the mid-1980s to 1990s for some facilities, 2) it informed insurers about groundwater issues at its basins in 1996, and 3) it knew it had groundwater concerns at all of its facilities by 2009, I calculated the approximate reduction in the time value of money starting at three different points from 1992 until 2009. This approach results in further reduction in recoverable system costs of $17,735,012 (start point of 2009) to $90,679,573 million (start point of 1992).

D. Adding together the cost reductions in Steps A through C results in an estimated system cost reduction of $218 million to $291 million.

III. RULES GOVERNING COAL ASH BASINS

Q. BRIEFLY DESCRIBE THE CATALYST OF NORTH CAROLINA'S 2014 CAMA RULE AND ITS PERTINENT PROVISIONS

A. DEQ filed four lawsuits in 2013 against DEP alleging violations of North Carolina law regarding unlawful discharges and groundwater contamination at the DEP facilities in North Carolina (as well as Duke Energy Carolinas (DEC) coal electric generating facilities in the State). Then, in February 2014, DEC released between approximately 30,000 to 39,000 tons of coal ash and 27 million gallons of coal ash basin water to the Dan River from DEC's Dan River facility as a result of the failure of a stormwater pipe that ran below an ash basin.

On March 12, 2014, Duke Energy announced short- and long-term plans as well as recommendations and strategies for moving forward after the Dan River release in a letter from Ms. Lynn Good, President and Chief Executive Officer of Duke Energy, to State officials (Hart Exhibit 1). Such plans included with regard to the DEP facilities:

- accelerating planning and closure of the Sutton ash ponds to include evaluation of lined structural fill solutions and other options,
- preparation and submittal of a conceptual closure plan for the Sutton ash basins within six months (i.e., by June 2014),

- removing water from the Sutton ash basins in the next 18-24 months (i.e., by September 2016 to March 2017),
- continuing to move ash from the Asheville plant to a lined structural fill solution,
- converting the two remaining units at Asheville to dry ash handling or retiring the facility,
- minimizing the potential of a similar discharge to Dan River by accelerating the removal of water from the ash ponds at all retired coal plants, and
- developing a comprehensive coal ash basin strategy including evaluating complete conversion of all facilities to dry ash handling (which eliminates the need for wet sluicing and ash basins).

Subsequently, North Carolina enacted the North Carolina Coal Ash Management Act (CAMA) in August 2014 (Session Law 2014-122[1]). CAMA was amended in June 2015 (Session Law 2015-110[2]) and July 2016 (Session Law 2016-95)[3]. In brief, some of the major provisions of CAMA with respect to coal ash basins include the following:

1. A procedure for prioritization of ash basins and timelines for their closure. High risk basins were required to be closed as soon as practicable but not later than December 31, 2019, intermediate risk basins were to be closed as

[1] https://www.ncleg.gov/EnactedLegislation/SessionLaws/PDF/2013-2014/SL2014-122.pdf
[2] https://www.ncleg.gov/EnactedLegislation/SessionLaws/PDF/2015-2016/SL2015-110.pdf
[3] https://www.ncleg.gov/EnactedLegislation/SessionLaws/PDF/2015-2016/SL2016-95.pdf

soon practicable but not later than December 31, 2024, and low risk basins were to be closed as soon as possible but not later than December 31, 2029. The initial CAMA rule designated the Asheville and Sutton facilities as high risk. A June 2015 CAMA amendment extended the timeframe for closure of the Asheville facility to as soon as practicable but not later than August 1, 2022. The July 2016 CAMA amendment classified the HF Lee, Cape Fear, and Weatherspoon facilities as intermediate risk and required closure as soon as practicable but not later than August 1, 2028. The remainder of the North Carolina DEP facilities (Mayo and Roxboro) were initially classified as intermediate risk, but were later reclassified as low risk following dam stability evaluations and connection of water supply wells in the area of the facilities to alternate or treated water supplies.

2. Prohibition on the construction of new and expansion of existing ash basins on or after October 1, 2014.
3. Prohibition on discharges of stormwater to ash basins on or after December 31, 2018 for inactive facilities or December 31, 2019 for active facilities.
4. Conversion of facilities to dry fly ash handling by December 31, 2018 and conversion to dry bottom ash handling by December 31, 2019 (or retirement of the facility prior to that time). Dry handling ash refers to handling of ash by means other than using liquids to sluice the ash to basins.
5. Accelerated timelines for submission of groundwater assessment plans (December 31, 2014) and corrective action plans (up to 180 days from submission of groundwater assessment plans) for restoration of

groundwater quality, if corrective action is deemed necessary.

6. Accelerated timelines to perform receptor surveys (by October 1, 2014) to identify water supply wells in the area of the coal ash basins and to provide permanent water supplies for households within a 0.5-mile radius of a compliance boundary of an ash basin (by October 15, 2018).
7. Accelerated timelines for identification (by December 31, 2014), permitting, sampling, and possible corrective action for all discharges from coal ash basins including toe drains and groundwater seeps.

Obviously, North Carolina's CAMA rule does not apply to the Robinson facility near Hartsville, SC.

On May 14, 2015, DEP pleaded guilty to criminal negligence in Federal Court: 1) for failure to maintain riser structures in two coal ash basins at the Cape Fear facility which allowed unauthorized discharges of coal ash wastewater into the Cape Fear River from at least January 1, 2012 through January 24, 2014; 2) for allowing discharges of groundwater from seeps with elevated levels of chloride, arsenic, boron, barium, iron, and manganese from a coal ash basin at the HF Lee facility into a drainage ditch that discharged to the Neuse River from at least October 1, 2010 through December 30, 2014; and 3) for allowing discharges from an unpermitted engineered seep at the Asheville facility into the French Broad River from at least May 31, 2011 through December 30, 2014. (Hart Exhibits 2 and 3).

Q. BRIEFLY DESCRIBE EPA'S 2015 CCR RULES.

A. The EPA Administrator signed the Disposal of Coal Combustion Residuals

(CCRs) from Electric Utilities final rule on December 9, 2014, publishing the rule in the Federal Register (80 FR 21301[4]) on April 17, 2015, with the rule becoming effective on October 14, 2015. There have been subsequent amendments to the rule (*see* 81 FR 51802[5] dated August 5, 2016 and 83 CFR 36435[6] dated July 30, 2018). EPA's 2015 CCR rule includes the following:

- CCRs disposed in landfills and ash basins would continue to be managed as non-hazardous wastes.
- The rule establishes national minimum criteria for existing and new CCR landfills and existing and new CCR surface impoundments and expansions. These criteria include location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care, and recordkeeping, notification, and internet posting requirements.
- The rule requires existing unlined CCR surface impoundments that are contaminating groundwater above a regulated constituent's groundwater protection standard to stop receiving CCR and either retrofit or close, except in limited circumstances.
- The rule requires the closure of any CCR landfill or CCR surface impoundment that cannot meet the applicable performance criteria for

[4] https://www.federalregister.gov/documents/2015/04/17/2015-00257/hazardous-and-solid-waste-management-system-disposal-of-coal-combustion-residuals-from-electric

[5] https://www.federalregister.gov/documents/2016/08/05/2016-18353/hazardous-and-solid-waste-management-system-disposal-of-coal-combustion-residuals-from-electric

[6] https://www.federalregister.gov/documents/2018/07/30/2018-16262/hazardous-and-solid-waste-management-system-disposal-of-coal-combustion-residuals-from-electric

location restrictions (such as height above the water table) or structural integrity. Note that all of the DEP facilities (except the Cape Fear facility which is not subject to the CCR rules) had one or more basins which failed to meet the location restriction of being at least 5 feet above the uppermost aquifer. In addition, the following facilities did not meet the location restriction for wetlands: Asheville, HF Lee, Roxboro, Sutton, and Weatherspoon.

The ash basins at the Cape Fear facility are not covered by the federal CCR rule because the plant stopped producing electricity prior to October 19, 2015 and no CCR has been placed in any of the basins since that date.

Q. BRIEFLY DESCRIBE PRIOR EPA RULINGS AND DRAFT RULES APPLICABLE TO CCRs?

A. Although there are several rulings and draft rules that proceeded EPA's 2015 final CCR rule, the primary rulings and draft rules are the 2000 Regulatory Determination regarding CCRs and the June 2010 Proposed Rule for CCRs. These are briefly discussed below.

<u>May 2000 EPA Regulatory Determination</u>

In May 2000, EPA issued a Notice of Regulatory Determination on Wastes from the Combustion of Fossil Fuels (65 FR 32214) which is attached as Hart Exhibit 4. This notice explained EPA's conclusion that CCRs did not warrant regulation as a hazardous waste under subtitle C of the Resource Conservation and Recovery Act (RCRA). However, EPA concluded that CCRs did warrant regulation as a non-hazardous waste under subtitle D of RCRA when they are disposed in landfills or ash basins. The notice indicates that there was adequate evidence at the time that CCRs could pose a risk to human health and the environment if not properly managed, and EPA had concerns due to the fact that adequate controls such as bottom liners in basins and groundwater monitoring may not be in place at many locations. EPA referenced a 1995 study by the Electric Power Research Institute (EPRI) which indicated that 60% of ash basins constructed between 1985 and 1995 had bottom liners, and 26% of all coal ash basins (regardless of construction date) had bottom liners. Bottom liners minimize the potential for leaching of metals and other inorganics from CCRs in ash basins into groundwater by using a physical barrier to separate the ash basin solids and liquids from underlying soil. The EPRI study also indicated that groundwater monitoring was being performed at 65% of all coal ash basins constructed between 1985 and 1995, and that groundwater monitoring was conducted at 38% of all coal ash basins. Therefore, at least some portion of the electric power industry was utilizing bottom liners and groundwater monitoring as early as 1995 regardless of the age of the coal ash basins.

In the 2000 ruling, EPA identified 11 "proven" damage cases from CCRs landfills and ash basins. EPA considered a "proven" damage case to be one where a primary drinking water maximum contaminant level (MCL) had been exceeded in off-site groundwater or surface water. Note that a primary drinking water MCL is used in Federal regulations to determine the suitability of water for drinking based upon health-based criteria. In addition to the eleven "proven" damage cases, EPA also identified 36 additional "potential" damage cases where groundwater impacts above primary MCLs were located under or within close proximity to a landfill or basin and did not extend off-site or where there were exceedances for secondary drinking water MCLs. A secondary drinking water MCL is used in Federal regulations to evaluate the suitability of water for drinking water based upon factors such as taste and odor. Please note that both North Carolina and South Carolina have groundwater regulations and standards that are separate and distinct from Federal drinking water regulations as discussed below in this section.

EPA also expressed concern with the placement of pyrite-containing coal mill rejects in the ash basins because of the potential to generate acidic leachate which could increase the solubility of some metals and lead to a greater potential of groundwater contamination. Pyrite is an iron sulfide mineral and, in the presence of an oxidizing environment, will form sulfuric acid. This is the same process that leads to acid mine drainage at mines.

The 2000 notice indicated that the utility industry, through its trade associations, had indicated a willingness to work with EPA to develop protective management practices (i.e., liners and groundwater monitoring) and some individual companies had committed to upgrading their practices.

<u>June 2010 EPA Proposed Rule for CCRs</u>

In June 2010, EPA proposed a rule to regulate CCRs at electric generating plants (75 FR 35128; Hart Exhibit 5), and this proposed rule was the precursor to the 2015 final CCR rule. In the proposed rule, EPA included two options for public consideration to manage CCRs in landfills and impoundments: one in which CCRs would be managed as a hazardous waste under RCRA subtitle C and the other in which CCRs would be managed as non-hazardous waste under RCRA subtitle D. As noted above, in EPA's final 2015 CCR rule, EPA confirmed that CCRs disposed in landfills and impoundments would be managed as non-hazardous wastes.

In the 2010 proposed rule, EPA provided information about the potential for leaching of metals from CCRs. The proposed rule notes that changes to fly ash and CCRs are expected to occur as a result of increased use and application of advanced air pollution control technologies such as flue gas desulfurization (FGD). These advanced air pollution control technologies reduce the amount of metals that are being released to the atmosphere by transferring them to ash and other air pollution control residues.

The proposed rule references a December 2009 report prepared by EPA (Characterization of Coal Combustion Residues from Electric Utilities – Leach and Characterization Data; Hart Exhibit 6) which provides the results of leach tests conducted on CCRs. The results indicated that the upper end of the leachate concentrations exceeded hazardous waste concentrations and/or drinking water levels for the metals antimony, arsenic, barium, boron, cadmium, chromium, lead, molybdenum, selenium, and thallium. The 2009 study further concluded that the leaching potential of CCRs was highly variable and was based upon complex interactions that are particular to the CCR tested and conditions in which leaching occurs.

The proposed ruling also identified additional "proven" and "potential" damage cases that had been identified since the 2000 Regulatory Determination as were summarized in a July 9, 2007 report: Coal Combustion Waste Damage Assessments (Hart Exhibit 7). In the 2007 report, EPA identified 24 "proven" damage cases (including the 11 identified in the 2000 Regulatory Determination) and 43 potential damage cases (including the 36 identified in the 2000 Regulatory Determination) of groundwater and/or surface water contamination from CCR landfills or impoundments. EPA expressed concern that the number of damage cases was increasing with time. One of the "proven" damage cases cited by EPA was at the DEP Roxboro facility, where the discharge of high concentrations of selenium in the 1970s and 1980s from the ash ponds to Hyco Lake affected fish reproduction, causing a decline in fish populations and resulting in largely economic damages of $877 million. North Carolina issued a fish consumption advisory for Hyco Lake in 1988. In 1990, DEP installed a dry ash handling system to meet new permit limits for selenium, which resulted in a rescission of the fish advisory in 2001.

The 2010 Proposed Rule also noted that results of additional risk evaluation conducted since the 2000 Regulatory Determination indicated that disposal of CCRs in unlined surface impoundments using wet methods can pose a significant risk to human health and the environment from toxic metals released to groundwater and surface water.

Q. PRIOR TO NORTH CAROLINA'S 2014 CAMA RULE AND EPA'S 2015 CCR RULE, WHAT REGULATORY RULES AND POLICY APPLIED

TO GROUNDWATER CONTAMINATION AT COAL ASH BASINS IN NORTH CAROLINA?

A. The North Carolina Administrative Code (NCAC) Title 15A Subchapter 2L Rules apply to all groundwaters in the state. The regulations were initially promulgated in 1979 in recognition of pollution becoming a major threat to the quality of the groundwaters of the state due primarily to changes in land use, including the rise of industrial activities such as coal-fired power plants. 15A NCAC 02L .0101(b)(1979). These Rules have been amended over time. The most recent version of the 2L Rules from 2013 is provided in Hart Exhibit 8. In accordance with NCAC 15A 2L .0103, the 2L regulations are intended to:

> protect the overall high quality of North Carolina's groundwaters to the level established by the standards and to enhance and restore the quality of degraded groundwaters where feasible and necessary to protect human health and the environment, or to ensure their suitability as a future source of drinking water.

The regulations include numerical standards (15A NCAC 2L .0202) referred to as the 2L Standards) which are maximum allowable concentrations resulting from a discharge of contaminants to the land or waters of the state which are intended to protect human health or which would otherwise render the groundwater unsuitable for its intended best usage. Each contaminant has a separate 2L Standard, and most standards are based upon their potential toxicity to humans. Contaminants with lower standards are typically more toxic than those with a higher standard. Standards can change over time as more updated toxicological data becomes available. For example, the 2L Standard for chromium in 1979 was 50 micrograms per liter (µg/L) but was changed to 10 μg/L in 2010 as a result of new toxicity studies showing that this metal warranted a more restrictive standard.

The rules also establish procedures for reporting and corrective action if there are violations of the standards. NCAC 15A 2L .0106 indicates that:

> Where groundwater quality has been degraded, the goal of any required corrective action shall be restoration to the level of the standards, or as closely thereto as is economically and technologically feasible as determined by the Department in accordance with this Rule.

Further, NCAC 2L .0106 provides a mandate that:

> Any person conducting or controlling an activity that results in the discharge of a waste or hazardous substance or oil to the groundwaters of the State, or in proximity thereto, shall take action upon discovery to terminate and control the discharge, mitigate any hazards resulting from exposure to the pollutants and notify the Department.

15A NCAC 2L .0106 also establishes the need to perform initial response actions, including a site assessment to determine the nature and extent of the contamination, receptor surveys to identify potential receptors of contaminated groundwater, and a proposal for implementation of corrective action to terminate and control the discharge.

Q. ARE THE 2L STANDARDS THE SAME AS THE FEDERAL DRINKING WATER STANDARDS?

A. No. North Carolina's 2L Standards are separate and distinct from Federal drinking water standards. As noted previously, North Carolina's groundwater rules are intended to protect groundwater resources for future use including potential use as drinking water. The Federal drinking water standards apply to regulated drinking water supplies and include a set of standards called MCLs.

In some cases, the North Carolina 2L Standards are more stringent than the Federal MCLs. For example, the North Carolina 2L groundwater standard for benzene is 1µg/L but the Federal drinking water MCL is 5 µg/L.

In addition, the 2L Standards do not include "primary" or "secondary" standards such as the Federal MCLs. As discussed previously, the Federal drinking water MCLs include primary MCLs which are based upon human health, and secondary MCLs which are based upon aesthetics. There is no analog to this in the 2L Standards. Although the 2L Standards take these factors into account, all 2L Standards are "equal" for the sake of compliance with the standards.

Further, just because a compound has a secondary MCL does not mean that it does not pose a risk to human health. For example, manganese does not have a primary MCL but does has a secondary MCL of 50 µg/L which is based primarily on taste and plumbing fixture staining considerations. However, EPA's 2004 Drinking Water Health Advisory for Manganese (Hart Exhibit 9) indicates that adverse health effects from manganese ingestion can occur at concentrations of 300 µg/L.

Q. PLEASE DESCRIBE "REVIEW BOUNDARIES" AND "COMPLIANCE BOUNDARIES" IN THE NORTH CAROLINA TITLE 15A NCAC 2L REGULATIONS AS THEY APPLY TO PERMITTED FACILITIES.

A. In the 2L Rules, there are specific rules that apply to "permitted" facilities. Because the ash basins at the DEP North Carolina facilities were permitted through National Pollutant Discharge Elimination System (NPDES) permits issued by DEQ, the ash basins are considered “permitted” facilities. Based upon my review, it appears that most of the ash basins at the DEP North Carolina facilities were issued NPDES permits in the 1970s (note that basins taken out of use before the 1970s were likely not permitted) and, in the case of the Mayo plant which did not start operation until 1983, in the early 1980s. For permitted facilities, the 2L Rules establish “review boundaries” and “compliance boundaries” around permitted waste disposal areas. Note that sections of the 2L Rules addressing compliance and review boundaries were not in the original 1979 2L Rules (*see* Hart Exhibit 10) but were added in the 1989 revisions to the 2L Rules.

NCAC 15A 2L .0107 indicates that for disposal systems individually permitted prior to December 30, 1983, the compliance boundary is established at a horizontal distance of 500 feet from the waste boundary or at the property boundary, whichever is closer to the waste boundary. NCAC 15A 2L .0107(k) indicates that a violation of the 2L Standards within the compliance boundary resulting from activities conducted by the permitted facility must be remedied through clean-up, recovery, containment, or other response when there is an imminent threat to public health or safety or the violation is in the bedrock, unless it can be demonstrated that the violation will not adversely affect or have the potential to affect a water supply well. NCAC 15A 2L .0108 indicates that a review boundary is established around any disposal system midway between the compliance boundary and the waste boundary, and that when the concentration of any substance equals or exceeds the standard at the review boundary as determined by monitoring, the permittee shall take action in accordance with the provisions of NCAC 15A 2L .0106(f) (described below).

The corrective action provisions of the rules at NCAC 15A 2L .0106 (e) indicate that:

> Any person conducting or controlling an activity that is conducted under the authority of a permit initially issued by the Department prior to December 30, 1983 pursuant to G.S. 143-215.1 or G.S. 130A-294, and that results in an increase in concentration of a substance in excess of the standards at or beyond the compliance boundary specified in the permit, shall:
>
> (1) within 24 hours of discovery of the violation, notify the Department of the activity that has resulted in the increase and the contaminant concentration levels;
>
> (2) respond in accordance with Paragraph (f) of this Rule;
>
> (3) submit a report to the Secretary assessing the cause, significance and extent of the violation; and
>
> (4) implement an approved corrective action plan for restoration of groundwater quality at or beyond the compliance boundary, in accordance with a schedule established by the Secretary…

NCAC 15A .0106(f), which is referenced in the above rules governing compliance boundaries and review boundaries, indicates the following:

> Initial response required to be conducted prior to or concurrent with the assessment required in Paragraphs (c), (d), or (e) of this Rule shall include:
>
> (1) Prevention of fire, explosion, or the spread of noxious fumes;
>
> (2) Abatement, containment, or control of the migration of contaminants;
>
> (3) Removal, treatment, or control of any primary pollution source such as buried waste, waste stockpiles, or surficial accumulations of free products;

> (4) Removal, treatment, or control of secondary pollution sources that would be potential continuing sources of pollutants to the groundwaters, such as contaminated soils and non-aqueous phase liquids. Contaminated soils that threaten the quality of groundwaters shall be treated, contained, or disposed of in accordance with rules in this Chapter and in 15A NCAC 13 applicable to such activities.

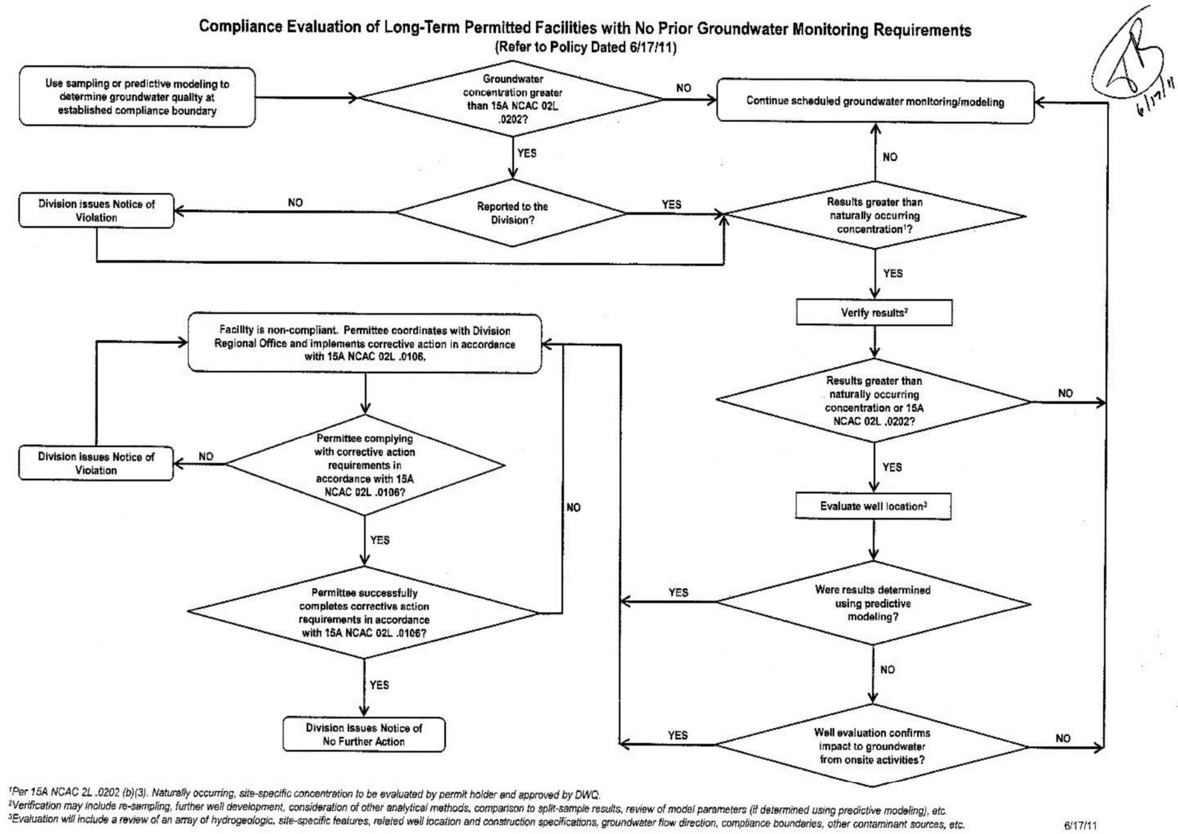
Q. DID DEQ ISSUE GUIDANCE TO DEP ON DEQ's POLICIES REGARDING THE 2L RULES AND ITS ASH BASINS?

A. Yes, based upon my review, DEQ issued a letter and a policy regarding the 2L Rules as they applied to permitted facilities in a letter dated December 18, 2009. (Hart Exhibit 11) DEQ indicated in the letter that, based upon a clarification from the Attorney General's Office, facilities permitted prior to December 30, 1983 that have groundwater standard exceedances are subject to the corrective action provisions of NCAC 15A 2L .0106 (*see* Hart Exhibit 8). This correspondence also indicates that, for permitted facilities to determine compliance with the 2L Standards, wells must be placed at or beyond the compliance boundary.

In addition, on June 17, 2011, DEQ issued a "Policy for Compliance Evaluation of Long-Term Permitted Facilities with No Prior Groundwater Monitoring Requirements" (Hart Exhibit 12).[7] This policy indicates that, if permitted facilities have operated for a long period of time and there has not been prior groundwater monitoring, it may be necessary to install wells at the

[7] Note that this policy was rescinded on September 29, 2015 because of the implementation of the CAMA and CCR rules.

compliance boundary rather that at the review boundary, and that decision is based upon multiple factors including the type of permitted activity, the geology, duration of the permitted activity (the longer a permitted facility has been in operation, the greater potential there is for impact at or beyond the compliance boundary), and the location of the compliance boundary (such as when the property line is closer than the 500 feet). The policy provided a flow chart (provided below) and indicated that if a facility is determined to be non-compliant after the steps outlined in the flowchart, then adherence to the corrective action requirements of NCAC 15A 2L .0106 is required. Following the flow chart below, in simple terms, this indicates that if a facility has concentrations above 2L Standards (and established background levels for naturally occurring compounds) at the compliance boundary, then the facility is non-compliant and should implement corrective action in accordance with 15A NCAC 2L .0106.



A note at the bottom of the flowchart indicates that naturally occurring "background concentrations" are to be determined on a site-specific basis by the permittee and approved by DEQ.

As noted in Sections V through XII below, DEP knew by the 2006 to 2008 timeframe (and in some cases in the 1990s) that there were 2L Standard exceedances inside the compliance boundary at multiple facilities, but made no effort to conduct groundwater monitoring at the compliance boundary to determine compliance with the 2L Standards until required to do so by DEQ in 2010. Had DEP conducted monitoring at the compliance boundary earlier at these facilities, it would have triggered the corrective action requirements of addressing its ash basins sooner. In some cases, groundwater impacts were detected outside the compliance boundary or in bedrock aquifers (to which the compliance boundary does not apply) which should have triggered the corrective action process sooner.

Q. WHAT ARE "BACKGROUND CONCENTRATIONS" IN GROUNDWATER AND HOW ARE THEY ADDRESSED IN THE 2L REGULATIONS AND GROUNDWATER CONTAMINATION INVESTIGATIONS IN GENERAL?

A. The primary compounds of concern released from coal ash basins to the environment may also occur naturally. Therefore, the presence of a metal in groundwater may be associated with naturally occurring or "background" concentrations. In some cases, naturally occurring concentrations of compounds can be present in concentrations greater than the 2L Standard for that compound. For that reason, the 2L Standards portion of the Rule at 15A NCAC 2L .0202(b) indicates that, when naturally occurring substances exceed the established standard, the standard shall be the naturally occurring background concentration as determined by the Director.

Q. IN YOUR 30 YEARS' EXPERIENCE, HOW ARE NATURALLY OCCURRING BACKGROUND LEVELS ESTABLISHED FOR METALS AND OTHER INORGANICS IN GROUNDWATER?

A. Naturally occurring background concentrations are established by installing one or more groundwater monitoring wells at locations upgradient and away from both the unit being investigated as well as other known or potential sources of contamination. Otherwise, the measurement of background concentrations will likely be affected by the unit being investigated or by another source and therefore will not be representative of background. For example, if one is trying to determine background concentrations in groundwater at a coal ash basin, installing a well upgradient of the basin but within or downgradient of a coal ash landfill or ash structural fill area would not be an appropriate background location because the landfill or fill area could also be causing groundwater contamination. The background well needs to be installed upgradient of potential sources of contamination.

In addition, background levels need to be established on a site by site basis. As discussed in greater detail below, the presence of metals in groundwater is based upon complex interactions and is dependent upon a number of site-specific factors such as the geology, metals content of the soil or rock, presence of other metals, and the oxidation state of the groundwater. In other words, background concentrations at one facility may be significantly different than those at another location.

Comparison to background concentrations can be performed using a simple direct comparison between the concentrations in a background well or wells and the concentrations in wells located downgradient of a unit. In addition, there are statistical methods that can be used to evaluate if there has been a statistically significant increase in concentrations in a well relative to background.

In my experience, the party addressing the potential groundwater contamination is responsible for making a technically defensible argument as to what the background concentrations are and whether a concentration downgradient of a unit being assessed is consistent with or above background. Although the 2L Standards indicate that background concentrations are "determined by the Director," in practice, a responsible party needs to make a technically defensible evaluation of background and then have DEQ review and concur or disagree with that evaluation. This is consistent with the footnote in the flowchart shown earlier regarding groundwater monitoring at long-term permitted facilities with no prior monitoring. It is also consistent with NCAC 15A 2L .0106 which indicates that, for requests involving approval or termination of corrective action, the responsibility for providing all information required by the rule lies with the person(s) making the request.

Q. WHAT WAS DEP'S APPROACH TO ESTABLISHING BACKGROUND LEVELS AT ITS FACILITIES PRIOR TO CAMA AND THE CCR RULES?

A. DEP initiated voluntary groundwater monitoring between 2006 and 2008 at its facilities as part of a Utility Solid Waste Activities Group (USWAG) program to evaluate groundwater conditions at coal ash basins as will be discussed in greater detail in Section IV below. At some facilities, groundwater monitoring had been initiated as early as the 1990s. In accordance with the 2006 USWAG Utility Industry Action Plan for the Management of Coal Combustion Products (Hart Exhibit 13), at least one background well was to be installed upgradient of a potential source of contamination to evaluate naturally occurring concentrations of metals in groundwater at each site and the data was to be evaluated to determine if there was a statistically significant increase above background. However, in many cases, either no background wells were installed, the alleged background wells were too close to the waste facility, or the alleged background wells were not upgradient of the basin.

Upon review of DEP's data for each facility, in a letter dated December 18, 2009 (Hart Exhibit 11), DEQ indicated the following with regard to several of the background and upgradient wells identified by DEP:

- Asheville – The proposed upgradient well located between Interstate 26 and the French Broad River at the southern portion of the map should be called a downgradient well.
- HF Lee – The upgradient well around the active ash basin was installed along the waste boundary and was deemed unsuitable for determining compliance. DEQ recommended the installation of a background well along the northern edge of the property.
- Cape Fear – The upgradient wells were located along the waste boundary and DEQ recommended a background well be installed north of the active basin.
- Roxboro – No background wells were identified and the upgradient wells were located within the compliance boundary.

Despite the express commitment to install background wells as part of the USWAG action plan and to evaluate conditions against background using appropriate evaluation methods, no additional background wells were installed at these facilities until 2010 and 2011. In some cases, DEP did not reliably establish or evaluate background conditions, but indicated that concentrations of metals in downgradient wells were believed to be naturally occurring when in fact they were not.

Q. IF GROUNDWATER CONTAMINATION IS IDENTIFIED WITHIN A REVIEW OR COMPLIANCE BOUNDARY AND THERE IS NO DATA BEYOND THE REVIEW OR COMPLIANCE BOUNDARY, DOES THAT MEAN THAT THERE ARE NO GROUNDWATER CONTAMINATION CONCERNS ASSOCIATED WITH THE PERMITTED FACILITY?

A. No. Monitoring within the compliance boundary (which includes the review boundary) is intended to provide a warning that a groundwater exceedance may be occurring at or beyond the compliance boundary. As noted in DEQ's December 18, 2009 letter to DEP (Hart Exhibit 11), the best way to determine compliance with the 2L Standards is to sample at or beyond the compliance boundary.

Q. IN YOUR EXPERIENCE, IS THE PRESENCE OF GROUNDWATER CONTAMINATION WITHIN A COMPLIANCE BOUNDARY A CONCERN THAT WARRANTS ADDITIONAL EVALUATION?

A. Yes. To the extent that monitoring is done within a compliance boundary and groundwater impacts are detected above background and standards, this serves as a warning that there may be impacts at or beyond the compliance boundary. If there are no detections within a compliance boundary above background and standards, then it may be reasonable to conclude that there is a low potential for impacts at the compliance boundary. Alternatively, if impacts are identified above background and standards, then additional evaluation should be performed to determine compliance at the compliance boundary. At a minimum, such evaluation might include additional monitoring over several monitoring events to determine concentration trends with time or scientifically valid modeling based upon site-specific information to evaluate the likelihood of contamination migrating beyond the compliance boundary. If the unit being monitored is 1) older (which would allow further migration), 2) the concentrations over time are increasing within the compliance boundary (indicating that the groundwater impacts are likely expanding), 3) the concentrations in the compliance boundary are remaining relatively stable (indicating that a source is still present and is continuing to contribute to groundwater impacts), 4) modeling indicates that concentrations are likely to exceed 2L Standards beyond the compliance boundary, and/or 5) sensitive receptors like surface water bodies or water supply wells are in the area of the impacts, these would be reasons that additional sampling at the compliance boundary should occur. This is consistent with the manner in which DEQ requested that DEP address groundwater impacts within the compliance boundary at the Sutton facility in the 1980s as discussed below.

Q. PRIOR TO EPA'S 2015 CCR RULE, WHAT REGULATORY RULES AND POLICY APPLIED TO GROUNDWATER CONTAMINATION AT COAL ASH BASINS IN SOUTH CAROLINA?

A. South Carolina's rules for groundwater protection are provided in Regulation 61-68 Water Classifications and Standards. These rules were initially promulgated in 1981 and have been amended over time. The most recent version of the rules is provided as Hart Exhibit 14. As indicated in R. 61-68 H., the intent of the rules is to maintain the quality of groundwaters in South Carolina consistent with their highest use. All groundwaters in South Carolina are classified as underground sources of drinking water unless otherwise classified, and the Department of Health and Environmental Control (DHEC) may require the owner or operator of a contaminated site to restore the water quality to a level that maintains and supports the existing classification and uses.

Regulation 61-68 H.9. establishes standards for groundwater which are the MCLs set forth in the state's drinking water regulations at R. 61-58. The state drinking water MCLs are the same as the Federal MCLs. There is no analogous concept to the North Carolina 2L Rules regarding a compliance boundary or review boundary to determine compliance with the standards for permitted waste disposal units such as coal ash basins. Therefore, a concentration above the MCL is considered an exceedance of the groundwater standard regardless of its distance from the waste boundary. Although not explicitly stated in R 61-68, my extensive experience in groundwater contamination investigations in South Carolina is that properly established naturally occurring background concentrations for compounds can also be used to determine compliance with the groundwater standards if the naturally occurring concentration exceeds the MCL.

IV. COAL ASH BASINS AND GROUNDWATER CONTAMINATION

Q. WHAT IS THE PURPOSE OF COAL ASH BASINS AT A COAL-FIRED POWER PLANT?

A. The burning of coal in coal-fired power plants produces several residuals including ash from the burning of the coal. The coal ash consists primarily of what is termed fly ash and bottom ash. Fly ash is a fine ash that is recovered from the flue gas by various means before it is discharged to the atmosphere. Particles that do not escape as fly ash primarily become bottom ash. Bottom ash is agglomerated ash particles that are too large to be carried in the flue gases and fall to the bottom of the furnace.

As the coal ash accumulates, it must be removed from the furnace and the power plant. One method used to manage the coal ash is to carry the ash with water in a process called sluicing to ponds. In the ponds, the coal ash particles settle out and accumulate in the bottom of the pond and the water is discharged to surface water pursuant to a NPDES permit.

Over time, the ash in the pond accumulates and reduces the volume of the pond for further ash accumulation. This also reduces the retention time of the water in the pond, which is important for ensuring that the ash settles out before water is discharged. Once a pond reaches near its capacity, the volume of the pond for additional ash can be increased by removing ash from the pond, allowing the water to drain from the ash in a "stacking" area, and then disposing of the dried ash in an on-site or off-site landfill or as on-site or off-site "beneficial fill." In addition, a pond reaching capacity can be expanded (laterally or vertically) or the pond can be closed and a new pond constructed. The need for an ash pond could also be eliminated by converting the facility to dry ash handling (i.e., not using water to transport ash away from the power plant).

Q. WHAT TYPE OF ENVIRONMENTAL CONTAMINATION IS ASSOCIATED WITH COAL ASH BASINS?

A. The primary environmental contaminants associated with coal ash basins are metals including, but not limited to, arsenic, boron, cadmium, chromium, selenium, iron, manganese, mercury, and vanadium, and other inorganics such as sulfate and total dissolved solids (TDS). The metals and other inorganics are derived from the coal which is used as a fuel source in the power plants. The coal that is burned in the power plants has metals that are in "naturally occurring" concentrations. After combustion, most of the organic components of the coal are burned off and the resultant ash now has a higher concentration of these metals, most of which are toxic. If toxic compounds such as metals are released to the environment and are present in sufficiently high concentrations, they can pose risks to human health as well as ecological receptors. Because coal ash has high concentrations of certain toxic metals and other inorganics, including those listed above, coal ash can pose an environmental concern.

Q. WHAT IS YOUR EXPERIENCE WITH COAL ASH AND METALS CONTAMINATION AND MANAGEMENT AND DISPOSAL OF CCR?

A. Some examples of my experience are:

- I have and am assisting several clients with assessment of groundwater impacts from permitted coal ash landfills and from locations where coal ash was placed as “beneficial fill”.
- I am assisting a client with the evaluation of environmental liability risks associated with closure of coal-fired power plants including coal ash basins.
- I am assisting clients with assessment and remediation of environmental contamination from metals at industrial facilities including, for example, a large chromium products manufacturer (primary compounds of concern are hexavalent chromium, vanadium, iron, and manganese), a metal salts manufacturing and recycling facility (primary metals of concern are cadmium, cobalt, nickel, and manganese), and a former sodium hydrosulfite manufacturing facility that at one time placed waste zinc and cadmium sludges into settling basins.

Q. FROM YOUR EXPERIENCE, BRIEFLY DESCRIBE SOME PRIMARY FACTORS CONCERNING THE FATE AND TRANSPORT OF METALS IN THE ENVIRONMENT.

A. The fate and transport of metals in the subsurface environment is complex. Many factors affect metals fate and transport including, but not limited to:

- The concentration and form of the metal. The higher the concentration of a metal, the more likely it is to move through soil and groundwater. In addition, most metals do not occur in their “pure” form in the environment but rather are typically in the form of metal complexes such as metal oxides or metal sulfides, and these metal complexes each have their own solubility which controls their ability to move in the environment. For example, iron in soil under typical conditions complexes with oxygen to form iron oxides which give shallow soils in the Piedmont region of North Carolina their characteristic reddish color. These iron oxides tend to be fairly immobile in the environment. However, other forms of iron such as iron chlorides are more mobile.

- Soil properties such as density, type of soil (i.e., clay versus sand), cation exchange capacity, pH, oxidation-reduction potential, amount of organic matter, and type and amount of other metals, cations, and anions.
- Properties of the groundwater such as rate of movement and hydraulic head distribution. In addition, the same parameters as noted above for soil will also affect the fate and transport of chemicals below the water table.

In general, after a metal is released to the environment, it will accumulate in soil until the capacity of the soil to retain it is exceeded. Once that occurs, the metal becomes mobile. Once a metal becomes mobile, downward vertical migration takes place in the soil above the “water table” until the metal enters the groundwater (unless the contaminant is released directly into the groundwater). The water table is the location below the ground surface where the ground becomes saturated with water (i.e., essentially all of the openings in the soil contain water instead of air). The depth to the water table varies based upon a number of factors but typically occurs within the upper 50 feet of the ground surface in the Piedmont region, with the shallowest depths occurring near surface water bodies and the greatest depths occurring at topographic highs such as hills.

Once in the groundwater, the metal is available for transport both vertically and horizontally with groundwater as the groundwater flows. Groundwater typically flows from upland areas at the top of hills to lower areas near streams. Groundwater discharges to streams in topographic lows and provides the "base" flow that we observe in streams when there is no precipitation. Once a metal becomes soluble and mobile in groundwater, the metal can migrate with groundwater downgradient and potentially impact groundwater "receptors" such as drinking water supply wells and surface waters such as streams and lakes.

Metals do not "degrade" in the environment but may change forms once they are introduced to the environment and, as noted above, different forms of metals may have different mobilities. For example, iron typically occurs in the environment in its oxidized state (i.e., in the presence of oxygen) as ferric iron (Fe^{+3}) which is a solid form and is fairly immobile. However, in the presence of certain contaminants or natural organics, the oxygen in the subsurface will become depleted and the iron will change to its ferrous state (Fe^{+2}) which is soluble and mobile. In groundwater, this reaction typically leads to the presence of higher concentrations of iron dissolved in groundwater. Higher concentrations of a compound in groundwater in turn may lead to further migration of that compound, a higher concentration at a groundwater receptor, and/or greater costs for remediation.

The fate and transport of metals is further complicated at facilities where wastes are being actively or continuously introduced into the environment over time such as coal ash basins. For example, the capacity of a soil below an ash basin to limit migration of a metal may not be exceeded for many years after the basin is placed into service and only then does the metal begin to migrate and impact groundwater. Therefore, although collection and analysis of groundwater samples below or downgradient of a basin may initially indicate that groundwater is not impacted, the groundwater may become impacted over time as the capacity of the soil to retain metals below and downgradient of the basin is reduced over time.

In addition, the wastes introduced to a basin may also change, which may also affect the fate and transport of contaminants over time. As an example, discharge of a hydrochloric acid solution into a water-filled basin during a metal cleaning process may lead to lower pH of water in the basin and increased leaching of metals from metal-bearing wastes in the basin. This is turn increases the potential for environmental impact through such mechanisms as 1) direct discharge of higher concentrations of metals from a basin to surface water, or 2) migration from the base of the basin into groundwater. Because subsurface conditions and waste characteristics may change with time, the presence and concentration of metals in groundwater may also change with time. That is why at facilities where contaminants are being actively introduced to the environment over time (such as an unlined coal ash basin), it is important to conduct and evaluate groundwater conditions over time so that potential groundwater contamination issues can be identified early and appropriate steps can be taken to mitigate the contamination as soon as possible.

Q. BESIDES COAL ASH, WHAT OTHER WASTE STREAMS OR MATERIALS ARE AND WERE DISPOSED IN THE COAL ASH BASINS OPERATED BY DEP?

A. In addition to coal ash, many other liquid wastes were disposed by DEP in the ash ponds. A review of NPES permit applications and permits for the DEP facilities indicates that other than coal ash, the liquid wastes discharged to the ash ponds included, but were not limited to:

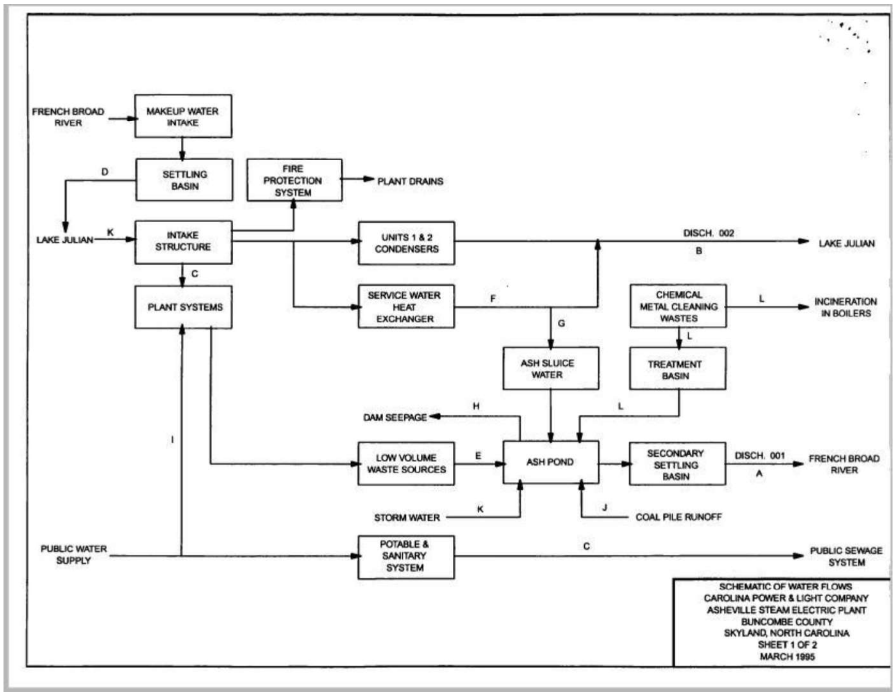
- treated domestic wastewater
- wastewater from metal cleaning using chemicals such as acids
- oily wastewaters
- coal pile runoff
- plant stormwater
- cooling water
- boiler blowdown
- preheater flush water
- water treatment wastewater
- cooling tower blowdown
- floor drains

- fluidized gas desulfurization (FGD) and other air pollution control systems wastewater
- combustion plant wastewaters
- tank and drum rinse waters
- tank farm runoff
- sumps
- vehicle rinse water
- landfill leachate
- sandblast material
- dredging material
- gypsum and limestone pile runoff
- fire protection system

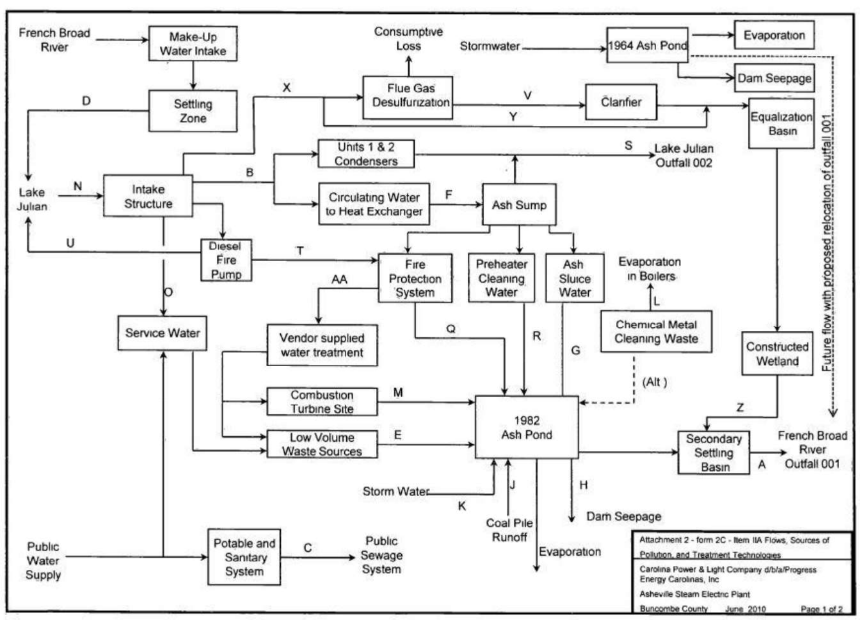
Some of these are considered "low volume" wastes because they enter the pond in fairly low volumes as compared to the higher volume of the ash transport waste. In addition, in some instances, treatment of the water entering the pond was needed to maintain acceptable pH or to reduce metals concentrations in the discharge outfall to the receiving stream water. For example, at the Sutton facility, aluminum sulfate was added to the sluiced water to promote settling of solids to comply with selenium discharge requirements from the basin outfall.

Generally, the number of different wastewater streams, including FGD system wastewaters, increased with time at the DEP facilities, presumably because the ash basins were a convenient location to place wastewaters and there would be considerable dilution of those waste streams in the basins. In general, additional wastewater streams such as FGD system wastewater were added to the basins over time. For example, a comparison of the process flow diagrams from the 1995 and 2010 NPDES permit applications for the Asheville facility is provided below which illustrates such additions.

1995 PERMIT PROCESS FLOWS



2010 PERMIT PROCESS FLOWS



As illustrated, between the 1995 permit application and the 2010 permit application, additional wastewater sources were added to the Asheville ash basin, including preheater cleaning water, fire protection system water, and combustion turbine system water. Also note in the 2010 process flow diagram that the 1964 ash basin was idle expect for receipt of stormwater discharge. At this time, there was no outfall from the 1964 pond other than seepage into groundwater, dam seepage, and evaporation.

Q. PLEASE EXPLAIN HOW UNLINED COAL ASH BASINS LEAD TO GROUNDWATER CONTAMINATION.

A. As noted previously, coal ash is sluiced to coal ash ponds from the power plants where it enters the pond along with other process waste streams. The coal that is burned in the power plants has metals that are in "naturally occurring" concentrations. After combustion, most of the organic components of the coal are burnt off and the resultant ash now has a higher concentration of those metals. For example, boron in US coal has been measured at concentrations in the range of 1 to 350 milligram per kilogram (mg/kg; also referred to as parts per million or ppm), while boron in the ash from US coal has been measured in the range of approximately 30 to 6,500 ppm[8].

The ash in the basin settles to the bottom of the basin and accumulates in the bottom of the basin over time. Because large volumes of water are used for sluicing and for other waste streams that are placed in the pond, and discharge water from the pond is decanted off the top of the pond, the accumulated ash is typically wet. As a result, some metals present in the ash

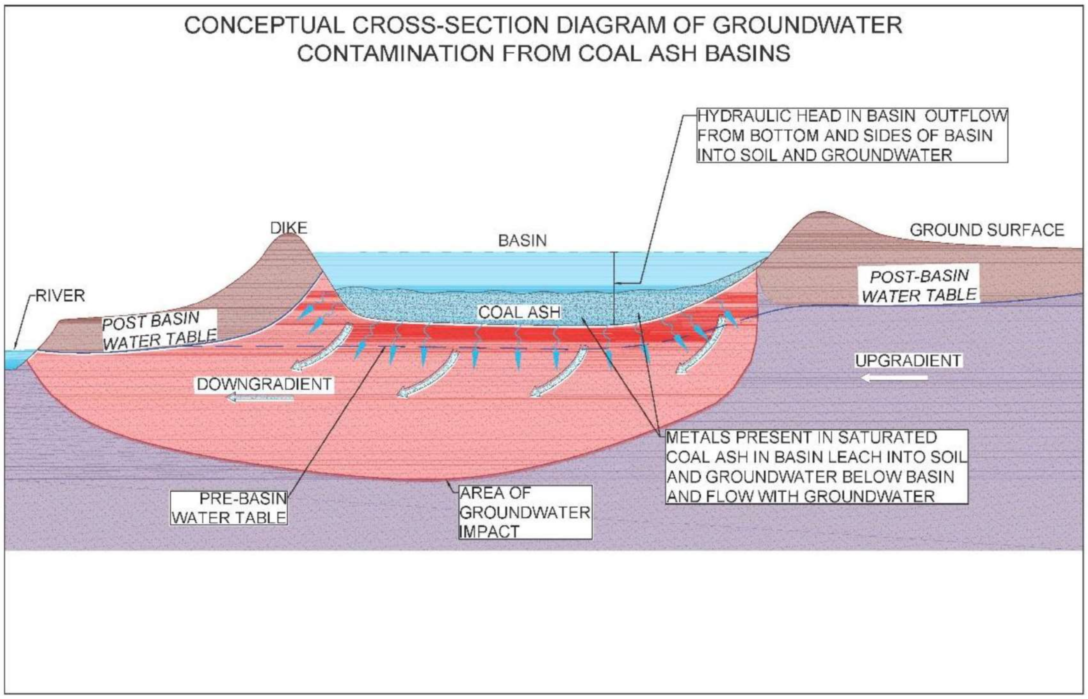
[8] https://nepis.epa.gov/Exe/ZyPDF.cgi/9101C057.PDF?Dockey=9101C057.PDF

leach out of the ash and enter the dissolved or aqueous phase and become an ash “leachate.” Because a hydraulic head is maintained in the pond, the metals-laden water in the pond migrates downward into underlying soil. A study done in 1991 at an approximate 40-acre ash basin at an electric generating facility in the Piedmont Region of the Southeastern US by the EPRI indicated that there is an estimated discharge from the base of the pond of between 200 million to 450 million gallons per year (Hart Exhibit 15). The DEP Asheville, Cape Fear, Mayo, and Roxboro facilities located in the Piedmont and Blue Ridge Regions of North Carolina have similar geology as that described in the 1991 study. The remainder of the DEP facilities are located in the Coastal Plain Region which would tend to have higher infiltration rates because of the typically more transmissive (i.e., sandier) nature of the subsurface in the Coastal Plain region.

If the bottom of the coal ash basin is located within the water table, the leachate will directly discharge to groundwater. Note that in some cases, because of the large volume of water migrating from the bottom of the pond, the water table may rise in the area of the pond and the bottom of an ash pond that was not in the groundwater table at the time of formation may be below the water table after operation for a period of time.

Attenuation of the metals may occur in the underlying soil and groundwater depending upon the complex processes discussed earlier. Once the capacity of the soil to attenuate a metal exceeds its attenuation capacity, then the metal will enter the underlying soil and may begin to flow with groundwater. Over time, more leachate entering the groundwater system can lead to higher groundwater concentrations and further migration distances in groundwater.

A simplified conceptual diagram of groundwater contamination from a coal ash basin is provided below:



Q. WHAT ARE THE PRIMARY FACTORS THAT CONTRIBUTE TO GROUNDWATER CONTAMINATION FROM UNLINED COAL ASH BASINS?

A. The primary factors that contribute to groundwater contamination from coal ash basins are:

- The mass of ash and concentration of metals and other inorganics that are present in the ash. The greater the amount of ash placed in the basin and the greater the concentration of metals and other inorganics present in the basin, the greater the potential for groundwater contamination.

- The length of time that the basin has been in operation. The longer the period of time the basin has been in operation, the greater potential that the concentration of the metals will increase in the bottom of the basin and the attenuation capacity of the underlying soil will be reduced. In addition, the longer the time the basin has been in operation, the greater the potential for a metal to migrate further with groundwater.
- The hydraulic head within the ash basin. The greater the hydraulic head in the basin, the greater the forces are to drive leachate through the base of the basin and into underlying soil and groundwater.
- The composition of the soil underlying the base. The less organic matter and coarser (i.e., sandier) the material underlying a basin, the greater the potential for groundwater impacts.

Q. WHAT POTENTIAL EFFECTS DO THE PROCESS WASTE STREAMS (I.E., OTHER THAN COAL ASH) DISCHARGED TO COAL ASH BASINS HAVE ON THE BASINS?

A. Other waste streams can have an effect on the complex geochemical interactions within the basins by adding other chemicals, changing pH, etc., and these actions can impact contaminant loading and the fate and transport of other metals and inorganics. For example, a January 13, 2014 Duke Energy "Ash Basin Closure Update" presentation to a Senior Management Committee (Hart Exhibit 16), indicates that FGD scrubber wastewater was creating chloride, bromide, and TDS groundwater issues at Zimmer (page 44). The Zimmer plant is located in Ohio. Duke Energy's recommendation, as stated in the presentation, was that it close all of the Zimmer plant's active ponds to mitigate impacts of scrubber wastewater (page 45).

In some instances, Duke Energy sluiced mill rejects containing the mineral pyrite to the ash basins. A study published in 1999 by EPRI entitled "Guidance for Co-management of Mill Rejects at Coal-Fired Power Plants" (Hart Exhibit 17) indicates that pyrite can form acidic leachates (sulfuric acid) as a result of pyrite oxidation in the basins which results in higher concentrations of sulfates, and metals such as iron, nickel, and arsenic. Pyrite is an iron sulfide mineral, and pyrite oxidation is the same process that causes acid mine drainage at older mining facilities. Similarly, the 1991 EPRI study of the Southeastern US power plant coal ash basin referenced previously (Hart Exhibit 15) indicates that oxidation of co-disposed pyrite appeared to be responsible for increased acidity and increased concentrations of iron, nickel, and zinc in the ash basin water. The November 2011 NPDES permit application update for the HF Lee facility indicates that mill rejects and pyrites were being buried in the dry ash deposits of the pond for disposal.

Disposal of other wastewater streams also results in additional hydraulic loading to a pond, especially at a facility where there was conversion from wet handling to dry handling of fly ash, resulting in reduced water flows to the pond from that higher volume source. In addition, disposal of non-coal ash wastewater streams complicates and may delay the ultimate closure of the ash basins because a new discharge location must be identified and potential treatment of the wastewater stream discharged to the basin will need to be in place before full closure of the ash basin can occur.

Q. WHEN DO DOCUMENTS YOU REVIEWED INDICATE THAT THE EPA AND THE ELECTRIC INDUSTRY (INCLUDING DEP) WERE GENERALLY AWARE OF THE REASONABLE POTENTIAL FOR LEACHING OF METALS FROM COAL ASH AND ASSOCIATED ACTUAL OR POTENTIAL GROUNDWATER CONTAMINATION?

A. There have been many EPA and electric industry publications regarding the reasonable potential for leaching of metals from fly ash and/or groundwater contamination. I have summarized some select earlier documents below.

December 1978 – Study of Non-Hazardous Wastes from Coal-Fired Electric Utilities (Hart Exhibit 18)

In December 1978, EPA published a draft final report regarding the management and disposal of solid wastes from the electric utility industry. One of the purposes of the study was to evaluate the methods of utilization and management of fly ash, bottom ash, and air pollution control FGD scrubber sludge with respect to technical, geographical, environmental, and economic considerations. The report notes that the leaching of compounds from fly ash, bottom ash, and FGD scrubber sludge is an important consideration because of the potential for groundwater or surface water contamination, and that the concentrations of compounds in FGD scrubber sludge are high in relation to the coal ash leachate. A review of available leaching data from fly ash, bottom ash, and scrubber sludge indicated that the average concentrations of the following compounds exceeded or were near federal drinking water standards or irrigation water quality parameters: arsenic, boron, chromium, fluoride, manganese, mercury, molybdenum, and selenium. The average concentration of these same metals and cadmium in FGD sludge liquors also exceeded drinking water standards or irrigation water quality parameters.

August 1979 – Effects of Flue Gas Cleaning Waste on Groundwater Quality and Soil Characteristics (Hart Exhibit 19)

In August 1979, EPA published a study conducted in conjunction with the US Army Corps of Engineers Waterways Experiment Station to evaluate the effects on soil characteristics and groundwater quality from the disposal of flue gas cleaning wastes in pits and ponds. Three field sites were evaluated and, at all three sites, sludge and ash derived compounds were found to have migrated out of the area of the pit or pond and degraded the quality of groundwater. The groundwater impacts were less extensive at a site underlain by "impermeable" soil, but at the sites underlain by permeable soil, evidence of a groundwater impact plume was observed under and downgradient of the disposal pond or pit. The report indicates that the sludge/ash leachate moved through the underlying soil without appreciable interaction or attenuation of contaminants. Significant increases in concentrations of mercury, lead, iron, arsenic, chromium, sulfate, chloride, and sodium were identified at one or more of the three field sites.

March 1980 – Effects of Coal-ash Leachate on Ground Water Quality (Hart Exhibit 20)

In March 1980, EPA and the Tennessee Valley Authority (TVA) published a study of coal ash leachate and groundwater from work performed at two TVA coal-fired facilities. The results of the study indicated that the interstitial water in the pore spaces of the coal ash in basins (i.e., the leachate within the coal ash basin) contained high levels of TDS, boron, iron, manganese, and sulfate and acidic levels of pH as low as 2 (neutral pH is 7). Results of groundwater sampling in the area of the basins indicated elevated levels of TDS, boron, iron, manganese, and sulfate, although at lower concentrations than in the ash basin water which was attributed to attenuation mechanisms in underlying native soil. Figure 28 of the report included a "model" of leachate migration in groundwater from coal ash basins which is reproduced below.

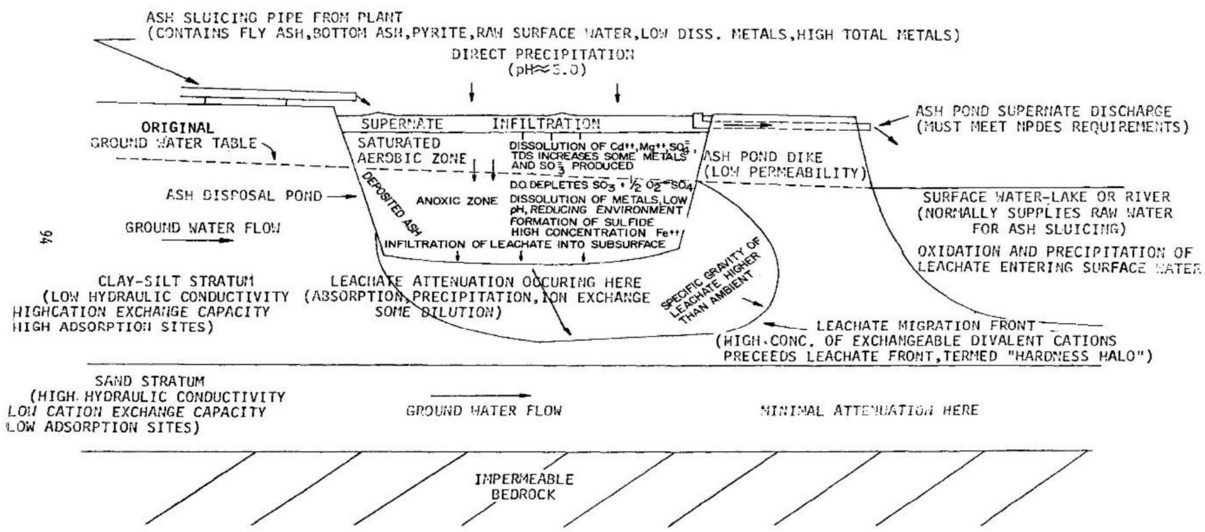


FIGURE 28. SCHEMATIC OF COAL-ASH LEACHATE GENERATION AND ATTENUATION

<u>February 1988 – Report to Congress – Wastes from the Combustion of Coal by Electric Utility Power Plants (Hart Exhibit 21)</u>

In 1988, EPA conducted a study to evaluate the potential adverse effects on human health and the environment from disposal of wastes from the combustion of coal and other fossil fuels. The study was completed to meet the requirements of RCRA which directed the EPA to complete a comprehensive study and report on the health and environmental effects of fly ash and other coal and fossil fuel combustion wastes. In 1978, following the establishment of RCRA in 1976, the EPA recognized that operations generating large volumes of waste such as a utility plant would require different regulations.

The report documents current waste disposal practices on a state by state basis. North Carolina and South Carolina were both listed as having leachate control requirements for solid waste disposal facilities, however North Carolina regulations specifically excluded surface impoundments from the requirement. As such, the surface impoundments were to be regulated by state water laws. According to the EPA research, by 1983, approximately 80% of the utility waste management facilities used some version of a treatment pond and state and local regulations were making liners and groundwater monitoring a requirement for these types of facilities.

Additional technologies or alternative disposal methods were discussed in the report, including installation of liners or leachate collection and groundwater monitoring. According to the report, lining was becoming a more common practice due to the concern that groundwater contamination may occur from "leaky ponds." Another technology alternative included groundwater monitoring and leachate collection in order to monitor contaminant migration. The suggested practice included groundwater monitoring downgradient of potential source areas, with upgradient wells to determine background concentrations for comparison of naturally occurring metals.

<u>November 1991 – Co-Management of Coal Combustion By-Products and Low-Volume Wastes: A Southeastern Site (Hart Exhibit 15)</u>

In 1991, EPRI conducted a multi-facility study to evaluate the potential effects of management of low volume wastewaters in coal ash basins and one of those facilities was located in the Piedmont Region of the Southeastern US. As noted previously, all of the DEP facilities are located in the Piedmont Region of North or South Carolina. The results of the study indicated that there were statistically significant increases in calcium, magnesium, strontium, and sulfate in downgradient groundwater as compared to upgradient. The report indicated that there were some increases in concentrations of metals in ash basin water which could be associated with other wastewater streams (ex., boiler cleaning) but concluded that the elevated metals in the ash basin water were the result of effects of pyrite oxidation from pyrite mill rejects placed in the pond. The report also indicates that testing indicated low attenuation mechanisms in the Piedmont Region soil below the ash basin through adsorption mechanisms. Adsorption is the process in which a compound like a metal in a liquid state is transferred onto a solid surface like soil.

<u>October 2006 Utility Industry Action Plan for the Management of Coal Combustion Products (Hart Exhibit 13)</u>

In October 2006, the Utility Solid Waste Activities Group (USWAG) issued an "action plan" with regard to management of CCRs. USWAG is an industry group that included over 80 electric utility companies at the time, including DEP. The purpose of the plan was to address concerns raised by EPA in its 2000 Regulatory Determination (discussed previously) as well as subsequent discussions with the industry. USWAG expressed concern that some of the damage cases cited in the 2000 Regulatory Determination did not reflect current industry practices and failed to recognize that even at those facilities where damages were noted, that the involved utilities had acted responsibly to address the environmental issues.

It appears that DEP agreed to conduct groundwater monitoring in accordance with the USWAG action plan in December 2007. With regard to groundwater, the USWAG action plan included the industry's <u>commitment</u> to adopt groundwater performance standards at facilities that manage CCRs and to implement a comprehensive monitoring program to measure conformance with the groundwater standards at facilities that managed CCRs. The action plan indicates that the goal of the groundwater monitoring program was to yield groundwater samples that would, to the extent possible, represent the quality of background groundwater unaffected by CCRs, and to detect CCR-related exceedances of groundwater performance standards. The action plan further indicates that the participating facility owners agree to 1) conduct semi-annual monitoring, 2) determine within a reasonable period of time after completing sampling if there has been a statistically significant increase over background levels, and 3) consult with the appropriate governmental agency and begin to develop a risk-management plan to address contamination within 90 days if monitoring confirms a statistically significant increase over background that exceeds a groundwater performance standard. As noted in Sections V through XII below, although DEP did implement the voluntary groundwater monitoring at its facilities in the 2006 to 2008 timeframe in accordance with the USWAG action plan (and in some cases used wells that had been installed in the early 1990s), DEP did not follow through with the action plan items after receipt of data.

<u>EPRI 2006 Characterization of Field Leachates at Coal Combustion Product Management Sites (Hart Exhibit 22)</u>

In 2006, EPRI published a study that characterized field leachate samples from various coal ash waste management processes. Previous leachate studies had primarily been performed using laboratory leachate testing procedures. The 2006 study included the collection and analysis of field leachate samples from various locations and by various methods such as leachate wells, seeps, and the ash/basin interface. The results documented high concentrations of arsenic, selenium, chromium, and mercury in leachate from landfill and surface impoundment samples.

<u>2007 Draft EPA Coal Ash Report (Hart Exhibit 23)</u>

In 2007, the EPA issued a draft report on the human and ecological risk assessment of coal combustion wastes. The report includes an analysis of coal-powered plant waste disposal practices and the potential risks from different site scenarios. Based on the risk pathways evaluated, the EPA concluded that surface impoundments posed the greatest risk for groundwater-to-drinking-water in cases of both unlined and clay lined units. The risk evaluation was based on a conceptual model simulating concentrations at a predetermined receptor. In completed risk assessments for human health, arsenic, boron, lead, cadmium, cobalt, and molybdenum posed potentially unacceptable risks.

Surface impoundments were noted to represent a higher risk than landfills due to higher waste leachate concentrations, more unlined units, and the hydraulic head from liquid waste.

<u>December 2009 EPA Characterization of Coal Combustion Residues from Electric Utilities (Hart Exhibit 6)</u>

In 2009, the EPA completed a study to determine the leaching potential of various wastes from coal fired power plants due to changes in air control technologies. Multiple samples of fly ash and FGD gypsum (a byproduct of FGD air pollution control) were collected and analyzed to determine metals in leachate from these waste products. Results of analysis of leachate from the fly ash samples indicated highly variable leaching potential of metals in the samples. However, the upper end of the concentrations exceeded drinking water exposure levels for antimony, arsenic, barium, boron, cadmium, chromium, lead, molybdenum, selenium, and thallium. The report recognized that attenuation of the metals would occur if the leachate were released to the environment.

Q. WHAT DO DEP'S INTERNAL DOCUMENTS YOU REVIEWED INDICATE ABOUT ACTUAL OR POTENTIAL GROUNDWATER CONTAMINATION FROM COAL ASH BASINS AT DEP'S FACILITIES AND DEP'S CONCERNS?

A. Below is a summary of select documents regarding potential and actual concerns regarding groundwater contamination at DEP facility coal ash basins. Please note that this is not an exhaustive list of documents but rather select documents over time.

August 1978 – DEQ Letter to Wilmington District of the Army Corps of Engineers Regarding the Draft Environmental Impact Statement for the Mayo Facility (carbon copied to DEP) (Hart Exhibit 24)

This letter indicates that DEQ and the Army Corps of Engineers had met to resolve concerns regarding DEP's request to construct an ash pond for the Mayo facility within the upper reaches of Crutchfield Branch (the Mayo facility began operations in 1983). This ash pond was eventually constructed. The expressed concern with regard to the ash pond was related to groundwater contamination and the resultant discharge of pollutants downstream of the dam on Crutchfield Branch. The letter indicates that the ash pond would be subject to a NPDES permit and that it was DEQ's intention to stipulate the following:

- DEP shall be required to complete the groundwater studies and provide controls as necessary for the prevention of pollutant materials from entering groundwater and thereby reentering the surface waters some point downstream of the proposed dam.
- DEP shall provide such testing as is necessary to assure that pollutants are not discharged to groundwater and thereby to the downstream point of the Crutchfield Branch in violation of the provisions stated above.

DEP had a study prepared by Moore, Gardner & Associates (MGA) in January 1979 (Hart Exhibit 24A) of the proposed location of the Mayo pond, presumably in response to the above request from DEQ. Based upon 1) short-term sorption tests which were performed by infiltrating coal ash pond water and coal ash from the coal ash pond at the Hyco Electric Plant (now the DEP

Roxboro facility) through three different 3.75-inch columns of soil from the proposed location of the Mayo pond, 2) groundwater samples from wells collected near the Hyco coal ash pond (which were not located downgradient of the pond), and 3) short-term leach tests identified in the abstract of another consultant study, the MGA report concluded that the soil at the proposed location of the Mayo ash pond was able to provide protection to groundwater from ash pond leachate by preventing significant leakage to groundwater and reducing concentrations of metals as the leachate traveled through underlying soil. This was the report's conclusion despite the fact that in at least one of the three leach tests there were increases in concentrations of iron, chromium, lead, and zinc in the leachate as compared to the coal ash pond water, including iron up to 17,300 µg/L in one of the samples.

The January 1979 MGA report contained the following recommendations regarding minimizing the potential for groundwater impact and early detection of potential groundwater impacts at the Mayo coal ash pond:

- The twelve test holes drilled in 1978 in the area of the Mayo ash pond were finished as observation wells "in order that periodic water-level measurements can be made and samples of water can be taken for analysis of the trace metals."
- "Special efforts" must be made to seal the possible leakage paths with the addition of natural clay and bentonite (a special clay type with a high swelling capacity that is typically imported) in those locations where the soil cover is thin or absent such as stream channels and rock outcrops.

It is unknown whether either of the above items was performed. However, based upon groundwater monitoring data provided by DEP, it does not appear that groundwater monitoring was initiated at the Mayo facility until 2008, approximately 30 years after groundwater monitoring was recommended by both DEQ in 1978 and DEP's own study in 1979. As noted in Section VII below, groundwater impacts and surface water impacts to Crutchfield Branch were identified after monitoring was initiated at the Mayo facility in 2008.

1984 to 1987 – Correspondence Regarding Groundwater Monitoring at LV Sutton Plant (Hart Exhibit 24B)

In the mid to late 1970s, the adjacent property owner to the east of the LV Sutton plant (at the time Hercofina) expressed concern to DEP and DEQ that higher levels of chloride being observed in Hercofina production wells were the result of operations at the LV Sutton plant. Records in DEQ's files indicate that as early as 1978, DEQ considered the unlined coal ash pond at the LV Sutton plant (now referred to as the Old Ash Basin or 1971 Ash Basin) a potential source of groundwater impacts. In 1983, DEP requested that the ash pond at the LV Sutton facility be expanded by constructing a new ash pond. Hercofina expressed concern about the expansion of the ash ponds because of the existing groundwater contamination issue and, after a number of meetings and discussions, DEP agreed to install a 12-inch clay liner as part of the construction of the new ash pond.

In March 1984, DEP submitted a modified design for the coal ash pond which included installation of the 12-inch clay liner but also included raising the dikes of the Old Ash Basin. DEP indicated that the modified design was being submitted "[i]n light of new groundwater regulations and other considerations."

In a May 1984 memorandum, which referenced an unspecified 1979 report from EPA and a 1980 article in the journal *Ground Water* concerning the effect of fly ash disposal on groundwater, DEQ indicated that it had "very significant concerns" regarding the impact on groundwater quality from the Old Ash Basin and the proposed modifications to the Old Ash Basin. DEP noted that the referenced literature studies indicated significant degradation of groundwater. DEQ subsequently requested that DEP install and sample monitoring wells at the Old Ash Basin, and DEP agreed to install seven wells, including one background well. The New Ash Pond was constructed with a 12-inch clay liner and put into service in November 1985.

In April 1986, DEQ submitted a letter to DEP indicating that, as a result of review of the groundwater data collected from the monitoring wells at the LV Sutton Old Ash Pond, additional groundwater assessment needed to be performed in the area of the canals and coal ash basins. The letter notes that 1) it is possible that a violation of the TDS standard at the compliance boundary exists downgradient of the ash pond(s), and 2) that it is probable that the ponds have caused concentrations of chloride and TDS downgradient of the pond that are 50% of the groundwater standard. DEQ requested that a study be performed to demonstrate that the CP&L sources are not contravening and will not contravene groundwater standards and that the sources will not impact off-site potable water supplies. In June 1986, DEP proposed to install and sample six additional monitoring wells to evaluate compliance with the groundwater standards from the discharge canal, cooling lake, and the ash ponds. Based upon subsequent discussions with DEQ, 12 additional wells were installed at the site. In September 1987, as a result of the additional groundwater monitoring, DEQ issued DEP a Notice of Non-Compliance indicating that water and wastewater in the surface impoundments at the facility have contravened groundwater standards for TDS and chlorides at and beyond the compliance boundary. I discuss additional post-1987 groundwater assessment activities at the LV Sutton plant in Section X below.

It is apparent from the LV Sutton facility groundwater issues that, by the mid-1980s, DEP was aware of the following:

- DEQ had significant concerns about the presence of groundwater contamination from coal ash basins.
- Bottom liners were a potential method to minimize the potential for groundwater impacts.
- If concentrations of compounds were elevated from a coal ash pond but did not exceed the groundwater standards, they were of concern to DEQ and needed to be evaluated further.

November 2004 - LV Sutton Steam Electric Plant Long Term Ash Strategy Report (Hart Exhibit 25)

In 2004, DEP performed an evaluation of a long-term ash strategy for the Sutton plant because the Old Ash Basin (referred to as the 1983 pond in the report) was "operationally full" by 1993 and the New Ah Basin (referred to as the 1984 pond in the report) was reaching capacity. The document notes that the Old Ash Basin is unlined and was constructed with native sandy soil. Although the pond was operationally full, it was still permitted and being used on an occasional basis when there were issues that required the 1984 pond to be temporarily dry. The document notes that:

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

The report notes that the high levels of arsenic are potentially from the Old Ash Pond or the pre-ash disposal site (an area where ash was deposited prior to the ash ponds also known as the Lay of Land Area) and that the groundwater impacts are also a concern due to the presence of a county well within one-quarter mile of the monitoring well.

The document also notes that the pre-ash disposal site was scheduled to be cleaned up but that the cleanup never occurred, that "little attentions [sic] are currently being placed on [the pre-ash disposal] site," and that this area might see increased attention due to the higher level of attention being paid to the ash ponds.

As discussed in the previous section, DEP knew about groundwater issues with the ash ponds at the Sutton facility in the mid-1980s and received a Notice of Non-Compliance from DEQ in 1987 for groundwater impacts at and beyond the compliance boundary. Although the Old Ash Basin was operationally full in 1993, closure of the basin did not start until after the Dan River spill occurred in 2014 and the Sutton facility was designated by CAMA as "high risk."

<u>February 17, 2006 - DEQ Permit to Progress Energy for an Ash Distribution Program (Hart Exhibit 26)</u>

In 2006, DEQ issued Progress Energy a permit for an ash distribution program applicable to the seven DEP North Carolina facilities. This program allowed DEP to use coal ash for structural fill at its facilities as well as off-facility locations provided certain criteria were met. The permit also allowed other uses of the coal ash such as uses for secondary roads, road traction control, roofing materials, and concrete products.

Section IV of the permit titled "Groundwater Requirements" indicates the following with regard to areas where ash is placed under the ash distribution permit:

> *An exceedance of the Groundwater Quality Standards at or beyond the Compliance Boundary is subject to immediate remediation action according to 15A NCAC 2L .0106 (d)(2)*

Although this permit does not apply specifically to coal ash basins, the language in the permit issued to DEP with regard to groundwater impacts is clear: if there is an exceedance of a groundwater standard beyond the compliance boundary, immediate action is warranted in accordance with North Carolina regulations.

<u>August 2008 - Energy Supply Environmental Matters Summary (Hart Exhibit 27)</u>

This document appears to be a summary of topics for a meeting in August 2008 regarding DEP environmental matters. The item "USWAG Action Plan for CCP Groundwater Impact" indicates that DEP signed on to the USWAG program in December 2007. In 2007, wells were installed and sampled at Asheville, Cape Fear, and HF Lee, and existing wells were sampled at Robinson, Sutton, and Weatherspoon. The document indicates that monitoring at Sutton had resulted in observations of elevated values for certain parameters ("boron and manganese in background") in the compliance boundary well. (Note that it is unclear what the term "boron and manganese in background" means).

<u>January 2009, February 2009, and March 2009 - Power Operations Group: Top 5 Environmental Issues Summary (Hart Exhibit 28, 29, and 30)</u>

These documents provide a summary of environmental issues at the DEP facilities as well as "implications and actions" for those issues. The text indicates that groundwater monitoring revealed elevated levels of various compounds at all DEP coal plants within the ash ponds' review boundaries. The January 2009 document indicates that boron and manganese are elevated at the Sutton compliance boundary and near the property boundary, that Asheville has elevated levels outside the review boundary, and that DEP is adding groundwater monitoring points within the compliance boundary at the Asheville facility. However, contrary to the January 2009 document, the February and March 2009 documents only indicate that elevated levels outside the review boundary are present at the Asheville and Sutton facilities. The document indicates that DEP is working with state and local agencies and/or undertaking additional geotechnical studies, and that DEP had met with state and county agencies regarding the Sutton facility. The document further indicates that eliminating the source of groundwater contamination may require dry ash handling, removing ash from the ponds, or installing lined landfills.

These documents indicate that DEP had confirmed groundwater impacts at all eight DEP facilities, including beyond the compliance boundary at Sutton. As indicated in Sections V through XII below, groundwater impacts outside the compliance boundaries or in bedrock had also been detected by this timeframe at the Asheville, Cape Fear, and Roxboro facilities. In addition, it is apparent that DEP was aware of methods to control the sources of the groundwater impacts such as conversion to dry ash handling and removal of ash from the basins.

[BEGIN CONFIDENTIAL] [redacted]

[redacted] **[END CONFIDENTIAL]**

<u>December 2009 - Correspondence Between DEQ and DEP Regarding Voluntary Groundwater Monitoring (Hart Exhibit 11)</u>

As noted previously and as will be discussed in Sections V through XII below, DEP performed groundwater monitoring at the DEP facilities as part of the USWAG voluntary monitoring program in 2006 to 2008. Note that prior monitoring of some wells had been occurring at the Roxboro, Sutton, and Weatherspoon facilities as early as the mid-1980s, so existing wells at these facilities were used for USWAG sampling.

In March 2009, DEQ acknowledging that it had been receiving data from DEP as part of the voluntary monitoring program, requested figures of the well locations in relation to waste, review, and compliance boundaries, summaries of all of the data, and an evaluation of groundwater standard exceedances in relation to the boundaries and planned actions as a result of those exceedances in accordance with the corrective action provisions of NCAC 15A 2L .0106. In a letter dated April 30, 2009 DEP provided the requested information to DEQ.

In a letter dated December 18, 2009 (Hart Exhibit 11), DEQ provided facility-specific evaluations of the data submitted by DEP and requested that

DEP put groundwater monitoring wells at the compliance boundaries. DEQ indicated that the wells that DEP had placed inside the compliance boundary were not suitable to determine compliance with the 2L Standards, provided DEP with recommended additional monitoring well locations, and noted issues with some of the existing wells, including DEP-designated background wells.

<u>December 2009 – Increased Coal Combustion Product Production Summary (Hart Exhibit 33)</u>

This document indicates the following: 1) the DEP landfills and ponds were reaching capacity, 2) new facilities need to be constructed, 3) construction of new ash ponds would most likely not be allowed by new regulations, 4) landfill permitting will most likely meet increased opposition, and 5) groundwater studies could impact technical design requirements. The summary indicates that conversion of Mayo's ash system to dry ash handling was almost complete and that dry fly ash/dry bottom ash should "ameliorate risk" from the planned groundwater study at the facility.

It is apparent from this document that DEP was aware that dry ash conversions could positively affect groundwater contamination associated with its ash ponds.

<u>1996 to 2011 - Insurance Claims Documents (Hart Exhibits 34 and 35)</u>

DEP made notice to its insurance carriers for certain environmental claims in or about 1996. DEP and the insurance carriers executed certain "Standstill Agreements" so that the parties could potentially resolve the environmental claims while still preserving their rights and defenses. The initial standstill agreement included, in addition to other environmental claims, those for the ash ponds at the Cape Fear, HF Lee, Robinson, Sutton, and Weatherspoon facilities and the ash management areas at the Roxboro facility. Periodic extensions to the agreements were executed over time. In 2011, the standstill agreement was modified to include “Ash Pond Claims” at all eight DEP facilities.

In a letter dated September 7, 2011, counsel for DEP sent a letter to counsel for the insurance carriers (Hart Exhibit 34) which indicated reasons why it was important to resolve the ash pond claims and why action was going to be needed to remediate the DEP ash facilities. The letter notes the following:

- There is increased, aggressive regulatory oversight by the State of North Carolina with regard to ash ponds.
- Regardless of when EPA may act or what other states may do, North Carolina is taking aggressive action on coal ash facilities, commencing with the boundary well monitoring required by DEQ at the end of 2010.
- There are existing regulations (i.e., the North Carolina groundwater rules) that describe the corrective action process if there are exceedances at the compliance boundaries.
- While the EPA CCR regulations might be forthcoming, North Carolina regulations already provide for the same potential closure scheme.
- Exceedances are already being detected at the relevant DEP ash ponds.
- With the passage of time, the threat from these issues will be more expensive.

In a subsequent letter to the insurance carrier dated October 25, 2011

(Hart Exhibit 35), counsel for DEP indicates the following:

- Exceedances are being found in the boundary monitoring wells of the ash pond facilities, and that State orders on remediation stemming directly from ash basin contamination seem "inevitable."

A related email between DEP's counsel and an environmental specialist for DEP (John Toepfer, PE) indicates that as of August 2011, DEP had not completed closure plans for any pond in the system (Hart Exhibit 36). DEP was beginning to develop a closure plan for Weatherspoon because the coal fired plant was to cease operation in October 2011. Note that closure plans for the Weatherspoon ash basins were not developed until 2015 according to DEP's witness Bednarcik's testimony.

March 2011 - Duke Energy Position on the Regulation of Surface Impoundments and Landfills Used to Manage Coal Combustion Residues (Hart Exhibit 37)

As noted previously, in 2010, EPA proposed rules for the management of CCRs at coal-fired electric generating facilities. Although this document pre-dates Progress Energy's merger with Duke Energy in July 2012, the document does provide Duke Energy's position on the draft CCR Proposed Rule prior to the merger:

- There should be no mandatory phase out of wet handling of CCRs and low volume wastewater streams at basins that meet applicable dam integrity and groundwater performance standards.
- State groundwater performance standards should guide corrective action for CCR landfills and impoundments.

- Groundwater monitoring should be required at all CCR landfills and basins to determine compliance with state groundwater standards and that any unit not in compliance would be required to take appropriate steps to come into compliance or to implement a closure plan.

[BEGIN CONFIDENTIAL] [redacted]

[redacted]

[redacted]

[redacted]

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<u>2013 Ash Basin Closure Strategy (Hart Exhibit 40)</u>

This document is undated, but based on other documents, it appears that this document was drafted in 2013. The document notes the following:

- While the CCR rule is not expected before 2014, which introduces some uncertainty, <u>state requirements exist now</u> (*emphasis added*).
- It is important for the corporation to move forward with ash basin closures to minimize environmental risk and costs associated with maintaining an ash basin for an extended period of time.
- Dewatering the ash basins will over a relatively brief time reduce or eliminate seepage which the company is addressing now.
- Capping the basins soon will help begin the process of natural attenuation or other means to reduce constituents in groundwater.

- Ash basin closure has recently seen increased attention and scrutiny and this is only expected to increase while the ash basins have no approved closure plan and "reasonable efforts to close them are not underway."

November 4, 2013 Ash Basin Groundwater Summaries (Hart Exhibit 41)

This Duke Energy document provides a summary of groundwater monitoring data at all Duke Energy facilities including the DEP facilities. This document indicates that there have been exceedances of the groundwater standards at the compliance boundary of all DEP facilities, but none of the DEP facilities have potential receptors. The following identifies the constituents that were in exceedance of the 2L Standards at each DEP facility, identified receptors, and indicates what actions have been completed in relation to the exceedances:

- Asheville:
  - Compounds above Standards: chromium, nitrate, selenium, thallium, boron, chloride, iron, manganese, sulfate, TDS, and pH
  - Receptors: Five water supply wells identified side-gradient to plant.
  - Actions Completed: completed receptor survey and connected two residences to municipal water because of high iron and manganese in a water supply well.
- Cape Fear:
  - Compounds above Standards: arsenic, cadmium, selenium, boron, iron, manganese, sulfate, TDS and pH.
  - Receptors: Cape Fear River; no risks identified.

  - Actions Completed: None. Comments: Entire facility retired; field investigations for ash basin closure began in summer 2013.
- HF Lee:
  - Compounds above Standards: arsenic, chromium, boron, iron, TDS, manganese, and pH.
  - Receptors: Neuse River; no risks identified.
  - Actions Completed: None. Comments: Coal units recently closed; field investigations for ash basin closure to begin in summer 2013.
- Mayo:
  - Compounds above Standards: cadmium, thallium, chromium, iron, manganese, TDS, and pH
  - Receptors: Mayo Creek; identified as distant from ash basins
  - Actions Completed: None; dry fly ash conversion to be completed in 2014, pond to remain open for other wastewater streams.
- Robinson:
  - Compounds above Standards: arsenic, chromium, sulfate, TDS, and pH.
  - Receptors: Lake Robinson
  - Actions Completed: None; coal fired unit recently closed. Separate inactive basin does not have groundwater monitoring network.
- Roxboro:
  - Compounds above Standards: chromium, iron, manganese, sulfate, TDS, and pH.

    - Receptors: Hyco Lake
    - Actions Completed: None; monofill is being developed over east ash basin to cap and close basin, the west ash basin is active and receives bottom ash.
- Sutton:
    - Compounds above Standards: antimony, arsenic, cadmium, lead, selenium, thallium, boron, iron, manganese, sulfate, TDS, and pH.
    - Receptors: Cape Fear Public Utility (CFPU) has two wells on property adjacent to plant. There are also non-potable industrial wells in area. In 2013, CFPU and DEP agreed to two-year project to connect the area served by the wells to Wilmington city water.
    - Actions Completed: Because of boron plume, two phase investigation completed in 2011 per DEQ; many of these wells incorporated into current well network. Monitoring began in early 1990s and wells were either within compliance boundary or distant from ash basins. Boron detected above NC Standard at the property line.
- Weatherspoon:
    - Compounds above Standards: iron, manganese, and pH.
    - Receptors: On-site cooling pond.
    - Actions Completed: Coal units have closed. Ash basin field investigations have been completed and closure design is nearly submitted.

The document indicates that Duke strongly believed the exceedances for iron, manganese, and pH are from naturally occurring conditions (which is not consistent with actual data as noted in the following sections) and notes that iron, manganese, pH, and TDS "only have secondary MCLs," implying that exceedances of these compounds are not of significance. The MCL standard has no relevance in determining compliance with North Carolina's 2L groundwater standards. As noted above, just because a compound has a secondary MCL does not mean that it does not pose a potential risk to human health and the environment. Based on the level of these exceedances (see below), there was and is a potential risk to human health and the environment.

<u>January 13, 2014 Ash Basin Closure Update Presentation to Senior Management Committee (Hart Exhibit 42)</u>

This document contains presentation slides and slide notes which indicate the following:

- The presentation emphasizes the "[n]eed to be very clear that our coal ash is impacting the groundwater in all locations." A table shows that there have been exceedances of groundwater standards at all of the DEP facilities.
- Mitigation of groundwater impacts generally equates to removing the source and allowing natural attenuation to occur.
- An example at the DEP Asheville station is provided indicating that levels of boron, selenium, and thallium have been decreasing in groundwater since the water level in the pond decreased, and that dewatering is the key driver to improved results.

- An example provided of the DEC Riverbend facility indicates that - with the plant shut down - the flow from the ash pond to groundwater is decreasing and groundwater impacts are improving.
- An example is also provided at the Duke Energy Cayuga facility, identified as an "advanced" coal ash remediation site. The notes indicate that a new lined pond was installed in 2005 and is the only lined pond at Duke Energy facilities. A voluntary ash pond closure was being coordinated with the state involving cap in place, and groundwater modeling indicates the "dramatic" effect that ash basin dewatering can have on decreasing groundwater impacts quickly.
- Scrubber wastewater is creating chloride, bromide, and TDS groundwater issues.
- The presentation notes indicate that scrutiny will only increase while "reasonable" efforts to close basins are not underway.
- "Internal" recommendations include "aggressively" pursuing closure of ash ponds at all decommissioned sites, closure of all active ash ponds, and the provision of a capital investment program to allow for closure of active ponds and the mitigation of impacts of scrubber wastewater.
- **[BEGIN CONFIDENTIAL]** [redacted]:

[redacted] **[END CONFIDENTIAL]**

Q. AFTER DETERMINATION OF THE PRESENCE OF GROUNDWATER CONTAMINATION, WHAT STEPS CAN BE TAKEN TO MINIMIZE GROUNDWATER CONTAMINATION FROM COAL ASH BASINS?

A. For active basins, steps that can be taken to minimize groundwater contamination from coal ash ponds include reducing the amount of coal ash which is entering the pond by converting the facility to dry fly ash and bottom ash handling (if not done already), removing ash from the basin on a frequent basis, eliminating wastewater streams and hydraulic loading from non-coal ash sources, removing the ash and installing a bottom liner, lowering the water level and/or dewatering the pond to decrease hydraulic loading, and ultimately pond closure. In addition, groundwater remediation can be initiated while the closure process is being evaluated to minimize the potential for additional increasing concentrations and migration of groundwater impacts. These items all take time to complete, have varying complexities depending upon the specifics of the facility, and all have significant costs associated with them.

Q. DO DOCUMENTS YOU REVIEWED INDICATE THAT DRY ASH HANDLING WAS CONSIDERED PRIOR TO CAMA AND CCR RULES FOR THE DEP FACILITIES THAT DID NOT ALEADY HAVE DRY ASH HANDLING?

A. Yes. As noted previously, in the early 1990s, discharge of selenium from the coal ash basins at the Roxboro facility affected fish reproduction and caused a decline in fish populations in Hyco Lake in the 1970s and 1980s. North Carolina issued a fish consumption advisory for Hyco Lake in 1988. In 1990, DEP installed a dry ash handling system to be meet new permit limits for selenium which resulted in a complete rescission of the fish advisory in 2001.

Documents reviewed from 2009 to 2014 also indicate that DEP was aware that conversion to dry ash handling would assist with addressing groundwater impacts associated with the basins and would be required to address inevitable coal ash basin closure. As noted above, estimated costs for these activities increased over time.

Q. DO DOCUMENTS YOU REVIEWED INDICATE THAT ASH BASIN CLOSURE AT THE DEP FACILITIES WAS CONSIDERED PRIOR TO CAMA AND THE CCR RULE?

A. Yes, documents indicate that as early as 2004, DEP knew that ash basin closure was likely to be required to address groundwater contamination issues, particularly for ash basins that were operationally full but not closed. Ash basin closures are also identified in documents from the 2009 to 2014 timeframe as a manner to address groundwater impacts and as part of plant retirement.

Q. WHAT EFFECT DID THE RELEASE OF COAL ASH INTO THE DAN RIVER FROM THE DEP DAN RIVER FACILITY HAVE ON HOW IT ADDRESSED ITS COAL ASH BASINS?

A. The 2014 release at Dan River had a significant effect on how DEP addressed its coal ash basins. Although groundwater contamination was identified at each of the facility coal ash ponds and there was an indication that the ponds would need to be closed either because of plant retirement or to address environmental concerns, little action had been taken to address coal pond closure, convert facilities to dry ash handling, or address the contamination. This all changed with the Dan River release. Afterward, Duke Energy committed itself to initiate and/or accelerate these actions as it outlined in its March 12, 2014 letter to State officials (Hart Exhibit 1). CAMA and the CCR rules followed and DEP was no longer able to postpone addressing its coal ash basins.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW ANOTHER INDUSTRY IN NORTH CAROLINA RESPONDED TO THE DETECTION OF GROUNDWATER IMPACTS IN ASSOCIATION WITH PERMITTED WASTE DISPOSAL INTO LAGOONS?

A. Yes. As an example, Diamond Shamrock (now Occidental Chemical) formerly operated a chromium ore processing facility in Castle Hayne, NC. (Note that beginning in 2001, this facility has been operated by Elementis Chromium.) Waste from the ore processing facility is treated and then residual solids and liquids are pumped as a slurry into on-site lagoons under a surface disposal of industrial byproducts residuals permit issued by DEQ. An initial approximately

16-acre diked lagoon was used for this purpose in 1971 and was out of use in 1991. Starting in 1977, residual solids were placed into former quarries that are approximately 150 acres in area.

Groundwater impacts at the facility (which included both the main plant process area and the lagoon) were identified in approximately 1975; groundwater impacts were reported to DEQ; and groundwater assessment and remediation were actively initiated with guidance from DEQ and outside consultants. By 1988, the plant had installed approximately 180 wells including 50 to 60 wells that were used for groundwater remediation. Occidental Chemical requested to voluntarily enter into a Consent Order with DEQ in 1988 to address the groundwater impacts at the facility, including those related to the lagoon where elevated levels of iron, TDS, and chlorides had been detected (Hart Exhibit 42A). Pursuant to the Consent Order, perimeter compliance wells were installed around the process plant area and the lagoon and quarries where residual solids were placed to enable direct sampling of groundwater at the compliance boundary. For locations where monitoring at the compliance boundary might not be feasible because of access limitations, DEQ allowed use of groundwater predictive modeling to predict groundwater concentrations at the compliance boundary and determine compliance with the 2L Standards. In addition, in 1990, background concentrations for iron were established for three different aquifer zones which were approved by DEQ.

In 1993, Occidental submitted a closure plan for the original lagoon (Hart Exhibit 42B). The closure plan included capping of the lagoon to prevent precipitation from entering the residual solids in the lagoon and thus minimizing the production of leachate that would serve as a continuing source of groundwater impacts. The cap consisted of an impervious membrane capped by a drainage layer and a protective soil layer. Closure of the lagoon was completed in 1994.

As noted above, residual solids were also placed into two former quarries under a permit issued by DEQ. Subsequent groundwater monitoring indicated that groundwater impacts above standards and background were present within the compliance boundary. Occidental then performed predictive modeling to evaluate if groundwater standards were likely to be exceeded at the compliance boundary. The compounds of concern were iron, TDS, chloride, and pH. In 1999, Occidental submitted a Corrective Action Plan (CAP) for the groundwater impacts associated with the lagoon and quarries using the processes of natural attenuation (Hart Exhibit 42C). As part of the plan, Occidental determined through predictive modeling the maximum concentrations of compounds that could be discharged to the quarries without exceeding the groundwater standards or background levels at the compliance boundary and instituted a process to maintain concentrations below those levels in the wastewater and quarries. Occidental also modified its wastewater treatment process to increase chloride removal efficiency. In addition, Occidental performed a study that determined the primary source of the TDS and chlorides was cement kiln dust added for metals stabilization; therefore, it implemented the use of an alternate treatment chemical for stabilization that had lower chloride content.

The above example provides several significant contrasts to the way a regulated party in North Carolina addressed groundwater impacts from permitted lagoons as opposed to the way that DEP addressed groundwater impacts from its coal ash ponds:

- Groundwater impacts detected as early as the mid-1970s within the compliance boundary were concerning and warranted further evaluation. In fact, very few wells were ever installed at or beyond the compliance boundary but corrective actions were taken.
- A lagoon used for residual solids disposal was closed in 1993 soon after it was taken out of use to minimize the potential for continuing groundwater impacts. The lagoon was closed with an impervious liner with overlying soil cover.
- Background concentrations were evaluated and determined in 1990 for each site aquifer and approved by DEQ.
- As a result of detected groundwater impacts associated with residual solids, modifications were made to address the sources of the groundwater impacts and corrective action plans were put into place and approved by DEQ.
- Violations of groundwater standards for compounds that DEP considered to have only “secondary standards” such as iron, TDS, and chlorides were considered significant and addressed.

- Groundwater monitoring and remediation were proactively addressed with DEQ as early as the 1970s and 1980s.

INTRODUCTION TO SECTIONS V THROUGH XII

The next sections provide a brief, facility-specific summary of coal ash basin groundwater monitoring data at each of the DEP facilities, including an evaluation of when groundwater impacts were identified at each facility, what was known about groundwater conditions at each of the facilities before CAMA and the CCR Rules, an evaluation of how and when DEP developed background concentrations, and a comparison of the data with 2L Standards and background concentrations developed by DEP. The summaries below primarily focus on data collected by DEP prior to the CAMA and CCR rules, but also discuss more recent data particularly as they relate to more recently developed background concentrations.

For ease of reference to the below discussions, figures which depict monitoring wells installed before 2014 are included as Hart Exhibits 43A through 50A for each of the DEP facilities. Excel spreadsheets developed by DEP of the groundwater sample analytical data as well as other sampled media such as surface water, soil, and coal ash are included in Hart Exhibits 43B through 50B for each of the DEP North Carolina facilities. The Excel spreadsheets also contain figures of the facilities with all of the sample locations depicted (including post-2015 monitoring well locations).

Further, information regarding each facility was also obtained from the 2019 Environmental Audits in Support of the Court Appointed Monitor provided in Hart Exhibits 51 through 58.

IV. ASHEVILLE STEAM ELECTRIC PLANT

Q. PLEASE PROVIDE A HISTORY OF COAL ASH BASINS AT THE PLANT.

A. The original ash basin (1964 ash basin) at the Asheville plant was constructed in 1964, expanded in 1971, and was approximately 41 acres (a 2018 report says 45 acres). The cumulative volume of ash in the 1964 pond was approximately 2.6 million cubic yards. In 1981, a second ash basin was constructed and began operation in 1982, at which time the original 1964 ash basin was taken out of service. However, according to NPDES application submittals, the 1964 ash basin continued to receive stormwater discharge but did not have outflow other than groundwater discharge, seepage, and evaporation. Accumulated water within the 1964 ash basin was also occasionally transferred to the 1982 pond.

Water was removed from the 1964 ash basin to increase storage and for storage of dredged CCR from the 1982 ash basin. An FGD wetlands treatment system was constructed on a portion of the 1964 ash basin in 2006 which operated until 2015, at which time approval was granted to discharge FGD wastewater to the sanitary sewer after pre-treatment.

The 1982 ash basin had an impoundment area of approximately 54 acres and received a cumulative ash volume of approximately 3.1 million cubic yards. In 2005, an interior dike was constructed to allow for an ash restacking project.

In 2007, as part of the construction of a new natural gas plant, DEP began to decommission the 1982 pond by dredging and dewatering the basin. The dredged CCR was taken to the Asheville airport for use as beneficial fill. Before closure of the 1982 ash basin, a temporary ash dewatering rim ditch system was constructed within the footprint of the 1964 ash basin for dewatering in 2014. CCR fly ash and bottom ash were sluiced to and then dredged in the rim ditch. Some plant wastewaters were also treated through the rim ditch system and center pond filters. To accommodate the 1982 ash basin closure, stormwater and low volume wastewaters were re-routed to the 1964 basin's open water area in around 2016. Excavation of the 1982 ash basin was completed in 2016, and full decommissioning of the 1982 ash basin was completed in January 2018. Closure of the 1964 ash basin began in 2017 and is ongoing.

In addition to sluiced coal ash, additional wastewaters placed in the basins at the Asheville facility included coal pile runoff, limestone and gypsum pile runoff, stormwater, fire protection system drainage, truck wash, low volume wastes, air preheater cleaning, combustion turbine wastes, and sludge from catch basins and sumps.

Q. PLEASE DISCUSS WHEN DEP BECAME AWARE OF GROUNDWATER CONTAMINATION ASSOCIATED WITH THE COAL ASH BASINS AT THE FACILITY AND BRIEFLY DESCRIBE RESULTS OF GROUNDWATER ASSESSMENT AND MONITORING OVER TIME AT THE FACILITY.

A. A brief summary of groundwater contamination is provided in bullet format below, which is then described in greater detail in the paragraphs that follow.

Summary

- Voluntary groundwater monitoring began along waste boundaries of the ash basins and within the compliance boundary in 2006, and iron, manganese, selenium, and boron were detected downgradient of the ash basin. Monitoring wells PZ-17D and GW-2 were sampled in 2006, are screened in bedrock, and indicated exceedances of boron (up to 2,350 µg/L compared to the standard of 700 µg/L), selenium (up to 46.7 µg/L compared to the standard of 20 µg/L), and manganese (up to 2,140 µg/L compared to a standard of 50 µg/L). Based on the 2L Rules, because compliance boundaries do not apply to groundwater impacts in the bedrock, corrective actions should have been initiated upon determination that an exceedance of the 2L Standards existed.
- Additional wells were installed in 2007 inside the compliance boundary (with the exception of GW-1 which was installed at the compliance boundary) and, in addition to the compounds above, concentrations of sulfate and total dissolved solids were detected above 2L Standards. Manganese was detected above the 2L Standard at the compliance boundary in monitoring well GW-1 in 2007. No background wells were installed.
- Background well CB-1 was installed at the compliance boundary in 2010 and background well CB-9 was installed in 2012.

- In 2010, at the request of DEQ, groundwater monitoring was started at and outside of the compliance boundary. Compounds detected above 2L Standards and background levels at or outside of the compliance boundary included boron (up to 2,640 µg/L compared to the 2L Standard of 700 µg/L), total dissolved solids (up to 1,300 µg/L compared to the 2L Standard of 500 µg/L and background value of 104.9 µg/L), manganese (up to 27,900 compared to the 2L Standard and background value of 725 µg/L) and iron (up to 42,000 µg/L compared to the 2L Standard and background value of 941 µg/L), sulfate (up to 1,000 µg/L compared to the 2L Standard of 250 µg/L), and thallium (up to 0.372 µg/L compared to the IMAC of 0.2 µg/L). IMAC refers to an Interim Maximum Allowable Concentration. An IMAC is an interim standard established by DEQ which is interim until a final standard is adopted but, until that time, an IMAC is treated the same as a 2L Standard with regard to determining compliance.
- Monitoring well CB-5 was installed outside the compliance boundary at the property boundary and indicated exceedances of iron and manganese as early as 2010.
- In 2015, cobalt was added as an analyte and was detected at concentrations up to 73.1 µg/L compared to the IMAC Standard of 1 µg/L and the background value of 6.9 µg/L.
- In the 2016 timeframes, there are significant increases in boron concentrations downgradient of the 1964 pond. This corresponds to the

timeframe when DEP began to re-route flows to the 1964 pond as the 1982 pond was being excavated.

- Due to the construction of a natural gas plant, dewatering and removal of coal ash from the 1982 basin began in 2007, which removed some of the coal ash mass. However, despite the presence of compounds above 2L Standards in compliance boundary and bedrock wells as early as 2006 and the fact that the 1964 basin had not been used since 1982 for other than stormwater purposes, DEP did not take proactive measures to address the groundwater impacts until after the Dan River spill. In fact, data indicates that groundwater conditions deteriorated as a result of re-routing of flows to the 1964 basin as part of the closure of the 1982 basin.

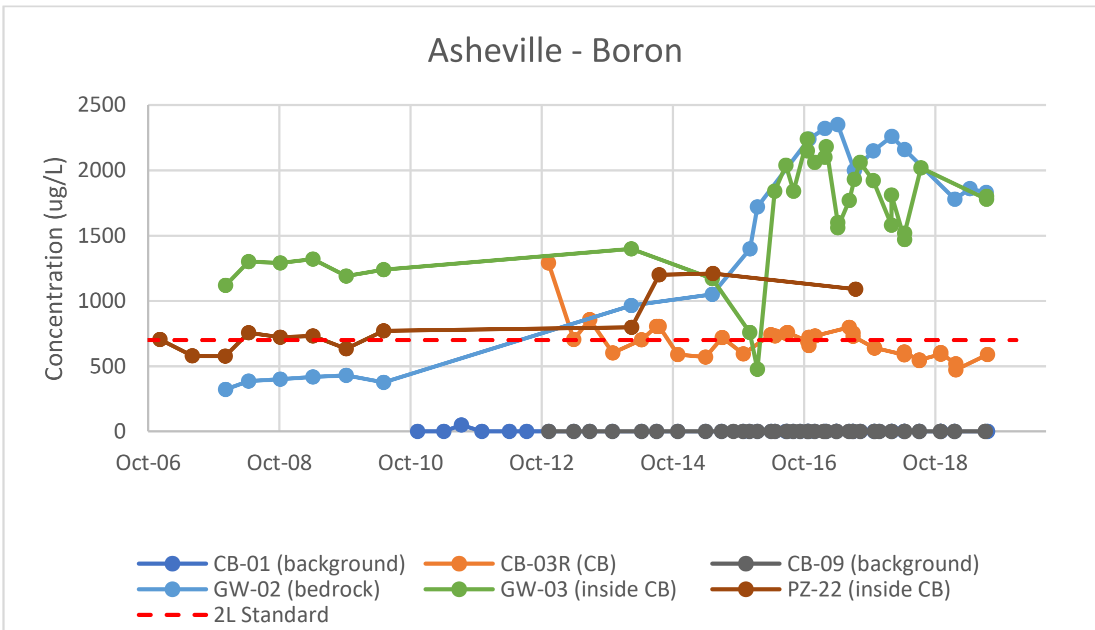
Site maps showing the well locations and groundwater flow are included as Hart Exhibit 43A and an Excel spreadsheet of groundwater data for the facility is included as Hart Exhibit 43B.

Details

Groundwater wells PZ-1S/D, PZ-8, PZ-12, PZ-17S/D, PZ-19, and PZ-22 were originally sampled in 2006. PZ-1, PZ-8, and PZ-12 are located within the ash basin waste boundary and the other wells are along the downgradient waste boundary. The wells within the waste boundary were only sampled one time in 2006 and indicated 2L Standard exceedances of boron, iron, and manganese in at least one sample. PZ-17S (inside compliance boundary or "CB") is screened in the transition zone and did not indicate 2L Standard exceedances between 2006 and 2019, and PZ-17D (bedrock, inside CB) is screened in the bedrock zone and indicated boron exceedances from 2006 through 2018 and selenium exceedances from 2006 through 2019. Based on the 2L Rules, the compliance boundary does not apply to contamination in the bedrock zone (wells PZ-17D and GW-2, discussed below) and therefore a concentration above the applicable standard equated to an exceedance and a violation of the 2L Rules. In early sampling events completed between 2006 and 2015, iron and manganese were detected above the 2L Standard in PZ-19 (inside CB). Iron, manganese, and boron were detected above the 2L Standard in PZ-22 (inside CB) from 2006 through 2017 (2015 for iron).

Additional groundwater monitoring began at the Asheville facility in 2007 with monitoring wells GW-1 through GW-5. GW-1 is located on the eastern compliance boundary to the east of the 1982 ash basin, and GW-2 through GW-5 are located along the western waste boundary of the two ash basins, within the compliance boundary. GW-1 (at CB) was later used in compliance boundary monitoring. Manganese was detected above the 2L Standard from 2008 through 2019 and cobalt was detected above the IMAC Standard between 2015 and 2019 in these wells. GW-2 (bedrock) is screened in bedrock and GW-3 (inside CB) is screened in the saprolite zone and both indicated concentrations of boron and manganese above the 2L Standards from 2007 through 2019. In addition, cobalt was detected above the IMAC as early as 2014 in both wells and total dissolved solids were detected above the 2L Standard from 2014 in GW-2 and 2016 in GW-3 through 2019. Sulfate was also detected above the 2L Standard in GW-3 between 2016 and 2019. GW-4 (inside CB) and GW-5 (inside CB) were installed in the transition zone and manganese and iron were detected above 2L Standards in the majority of the sampling events during which the wells were sampled between 2007 and 2019 (GW-5 was not sampled after 2014).

A graph showing downgradient concentrations of boron compared to background wells (as discussed below) is shown below.

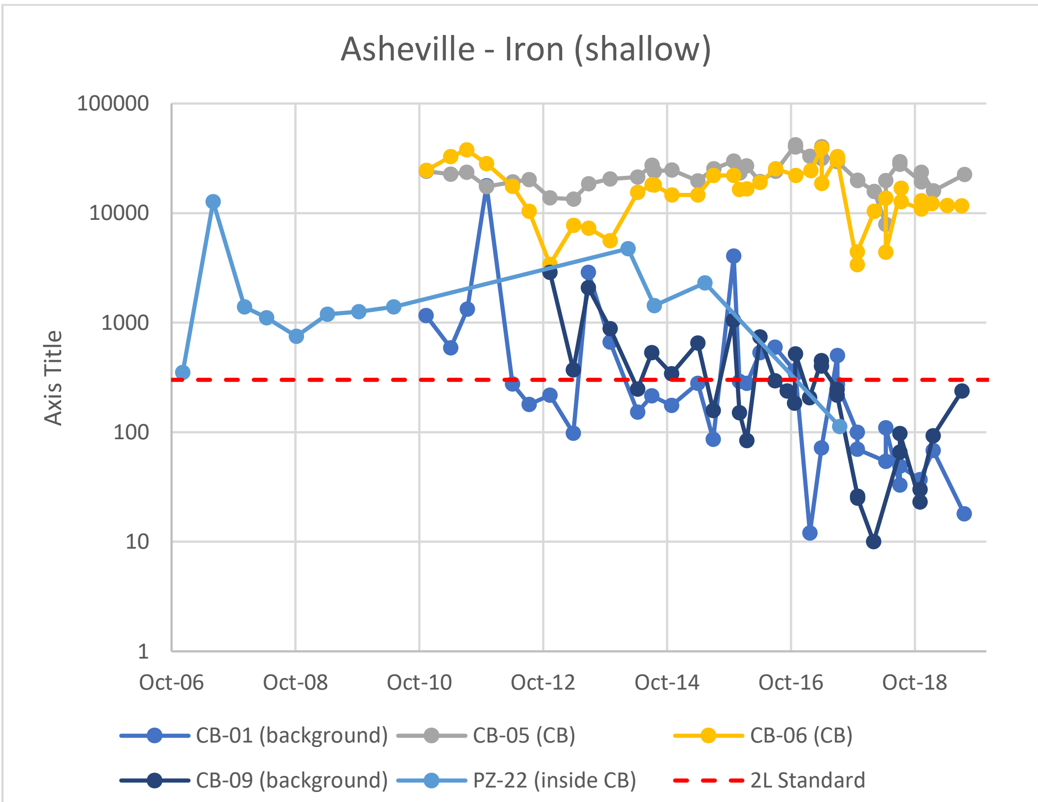


As indicated in the graph, there is a significant increase in boron concentrations in 2016 in wells GW-2 and GW-3 which are downgradient of the 1964 ash basin. This increase corresponds to the time when wastewater flows were re-routed to the 1964 basin as part of the excavation of the 1982 basin.

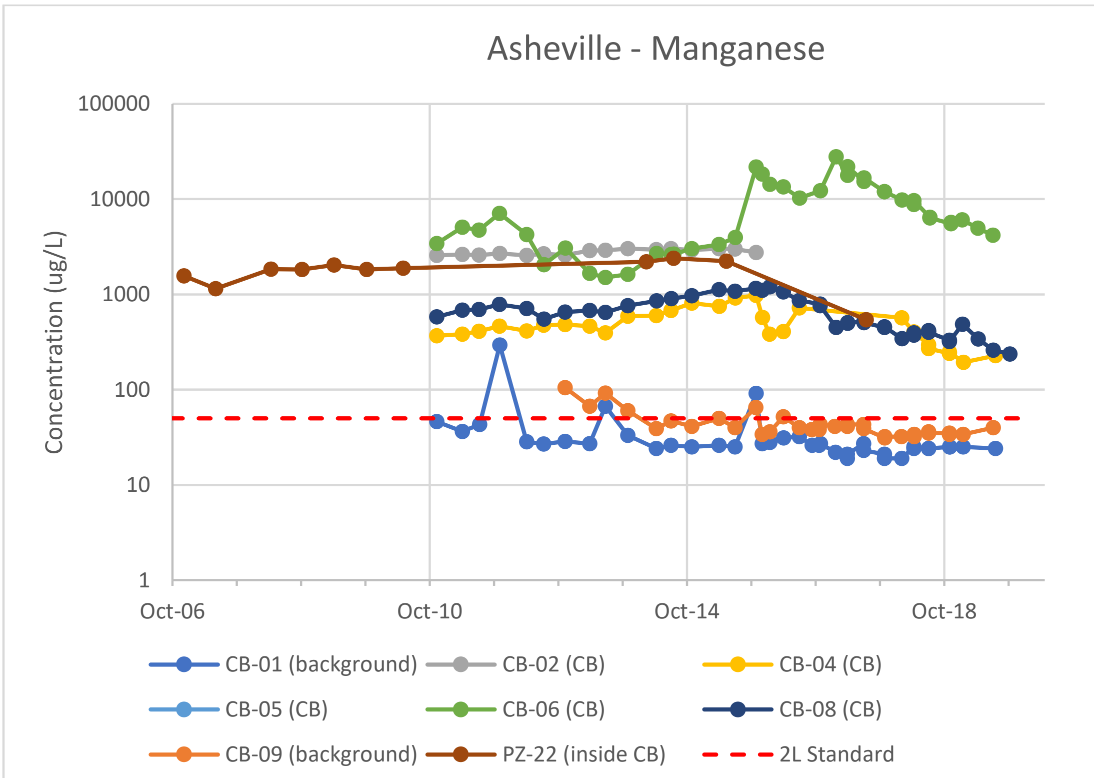
In 2010, groundwater monitoring at the compliance boundary was requested by DEQ and monitoring wells CB-2 through CB-8 were installed along the compliance boundary, with the exception of CB-5 which was installed outside of the compliance boundary along the property boundary. Background well CB-1 was installed in 2010 and background well CB-9 was installed in 2012; both were installed upgradient of the ash basins near the compliance boundary. Analytical data collected from the wells was included in the analysis of the background threshold values discussed below. With the exception of cobalt in CB-1 (background), no compounds were consistently detected above the 2L Standards or IMAC in the background wells, meaning the 2L Standards apply for 2L Standard compliance.

CB-2 (CB) and CB-3/3R (CB) are located southeast of the basin near off-site residences. CB-2 (CB) was sampled from 2010 to 2015 and indicated manganese concentrations well above the 2L Standard through that time period. CB-3 (CB) was sampled from 2010 through 2015 and CB-3R (a replacement well for CB-3) was sampled from 2012 through 2019. Iron and manganese were detected above the 2L Standards until 2015 in CB-3, and manganese was detected above the 2L Standard until 2019 in CB-3R. Boron concentrations appeared to increase from 2010 and were above the 2L Standard in the two wells between 2012 and 2017. Cobalt was detected above the IMAC from 2014 through 2019 in CB-3R, and thallium was detected above the IMAC in this well from 2010 through 2019.

In well CB-4 (CB) located south of ash basins, manganese was detected above 2L Standards from 2010 through 2019. In adjacent bedrock well CB-4B, iron was detected above the 2L Standard from 2010 through 2019. As mentioned above, CB-5 was installed outside of the compliance boundary along the downgradient property boundary. Iron and manganese were detected well above the 2L Standard from 2010 through 2019. In downgradient well CB-6 (CB), iron and manganese were also detected well above the 2L Standard from 2010 through 2019 and cobalt was detected above the IMAC Standard from 2015 through 2019. A graph showing iron concentrations in downgradient wells compared to background wells is shown below. Please note the y-axis is shown with a logarithmic scale to better compare the data.



Boron, total dissolved solids, and sulfate were also detected in CB-6 (CB) detected above the 2L Standards between 2010 and 2012, and total dissolved solids and sulfate were above standards again from 2015 through 2017. Boron was intermittently above the 2L Standard until 2017. CB-8 is located downgradient of the ash basin along the northwestern compliance boundary and indicated manganese and boron above the 2L Standards from 2010 through 2019. A graph showing manganese concentrations in downgradient wells compared to background wells is shown below. Please note the y-axis is shown with a logarithmic scale due to the high concentrations in some wells.



Although no background wells were installed prior to 2010, concentrations were retroactively compared to the background threshold values (BTVs) established in 2017. BTVs are background values established using statistical methods. BTVs were established using background well concentrations in CB-1 and CB-9. BTVs for cobalt, iron, and manganese exceed the 2L Standard, however concentrations detected in the site wells contained concentrations that exceeded the BTVs. The BTVs for boron and thallium did not exceed the 2L Standard and therefore concentrations detected in site wells exceeding the 2L Standard cannot be attributed to background concentrations, the 2L Standard is the applicable standard to determine exceedances, and the exceedances indicate a violation of the 2L Standard.

In 2015, as part of a Settlement Agreement with DEQ, DEP was required to implement accelerated remediation of groundwater at the Asheville facility due to the presence of off-site groundwater impacts. This system was started on or about 2017 and discharges extracted water to the 1964 ash basin/rim ditch.

V. CAPE FEAR STEAM ELECTRIC PLANT

Q. PLEASE PROVIDE A HISTORY OF COAL ASH BASINS AT THE PLANT.

A. The first ash basin at the Cape Fear facility was constructed in 1956 to the north of the former power production area. The 1963, 1970, and 1978 ash basins were constructed to the south of the power production area, and the 1985 pond was constructed to the east. In total, the ash basins cover approximately 173 acres and are estimated to contain approximately 4.8 million cubic yards of CCR.

The 1956 ash basin was no longer used following 1963, is approximately 12 acres, contains an estimated 350,000 cubic yards of CCR, and is covered with vegetation. The 1963 ash basin was approximately 21 acres until it was combined with the 1970 ash basin which added an additional 30 acres to its size. The 1963 basin contains an estimated 700,000 cubic yards of CCR, and the 1970 basin contains approximately 700,000 cubic yards of CCR.

The 1963 and 1970 ash basins were removed from use in 1978 and have since been covered with vegetation. According to the 2019 CAM report, a small portion of the 1970 basin is covered with water.

The 1978 ash basin operated from 1978 to 1985 and totals approximately 35 acres. The basin is estimated to contain approximately 700,000 cubic yards of CCR. This basin was decanted in 2017; however, according to the 2019 CAM report a portion of the southern end of the pond retains water. The largest ash basin on Site was constructed in 1985 and operated until 2012. The 1985 ash basin covers approximately 60 acres and contains an estimated 2.3 million cubic yards of CCR. Initial decanting of the basin was completed in 2017. According to the 2019 CAM report, water was still being decanted in August 2019. The Cape Fear facility was retired in 2012, and the facility was subsequently demolished.

In addition to sluiced CCRs, other wastewaters placed in the basins included coal pile runoff, fuel oil tank runoff, metal cleaning wastes, sand bed filter backwash, oil unloading drains, cooling tower and boiler blowdown, demineralizer regenerate, spent sandblast material, treated sanitary sewage effluent, and low volume wastes.

Q. PLEASE DISCUSS WHEN DEP BECAME AWARE OF GROUNDWATER CONTAMINATION ASSOCIATED WITH THE COAL ASH BASINS AT THE FACILITY AND BRIEFLY DESCRIBE RESULTS OF GROUNDWATER ASSESSMENT AND MONITORING OVER TIME AT THE FACILITY.

A. A brief summary of groundwater contamination is provided in bullet format below, which is then described in greater detail in the paragraphs that follow.

Summary

- In 2007, voluntary groundwater monitoring along the waste boundary of the 1985 ash basin and within the compliance boundary was completed and indicated concentrations of boron, sulfate, total dissolved solids, iron, and manganese above the 2L Standards. Monitoring well PZ-3D was screened in bedrock and indicated concentrations of manganese exceeding the 2L Standard (up to 891 µg/L compared to 2L Standard of 50 µg/L). Based on 2L Rules, the compliance boundary does not apply to the bedrock aquifer and therefore an exceedance of the applicable standards in the bedrock aquifer is a de facto violation of the 2L Rules. No background wells were installed until 2010.
- In 2010, groundwater monitoring was required along the compliance boundary by DEQ. Concentrations of iron (up to 64,100 µg/L compared to the 2L Standard of 300 and later developed BTV of 37,500 µg/L), boron (up to 3,160 µg/L compared to the 2L Standard of 700 µg/L), manganese (up to 18,000 µg/L compared to the 2L Standard of 50 µg/L and later developed BTV of 9,170 µg/L), sulfate (up to 790 µg/L compared to the 2L Standard of 250 µg/L and background value of 510 µg/L), and total dissolved solids (up to 1,300 µg/L compared to the 2L Standard of 500 µg/L and background value of 1,200 µg/L) were detected along the compliance boundary. Background wells BGMW-4 and BGTMW-4 were installed

outside of the compliance boundary to establish naturally occurring concentrations at this time.

- In 2010, bedrock wells CTMW-1, CTMW-2, CTMW-7, and CTMW-8 were installed downgradient of all of the ash basins and along the compliance boundary and indicated concentrations of manganese and iron well above the 2L Standard and background values for bedrock.
- In 2015, vanadium was added as an analyte and was detected at concentrations up to 18.1 µg/L compared to the IMAC of 0.3 µg/L and background value of 2.37 µg/L.
- Despite knowledge of groundwater impacts in bedrock and the compliance boundary in 2007 and evidence of more widespread detections at the compliance boundary in 2010, DEP did not perform mitigation activities to address the groundwater impacts until 2017, including in ponds that had not been used in a long time.

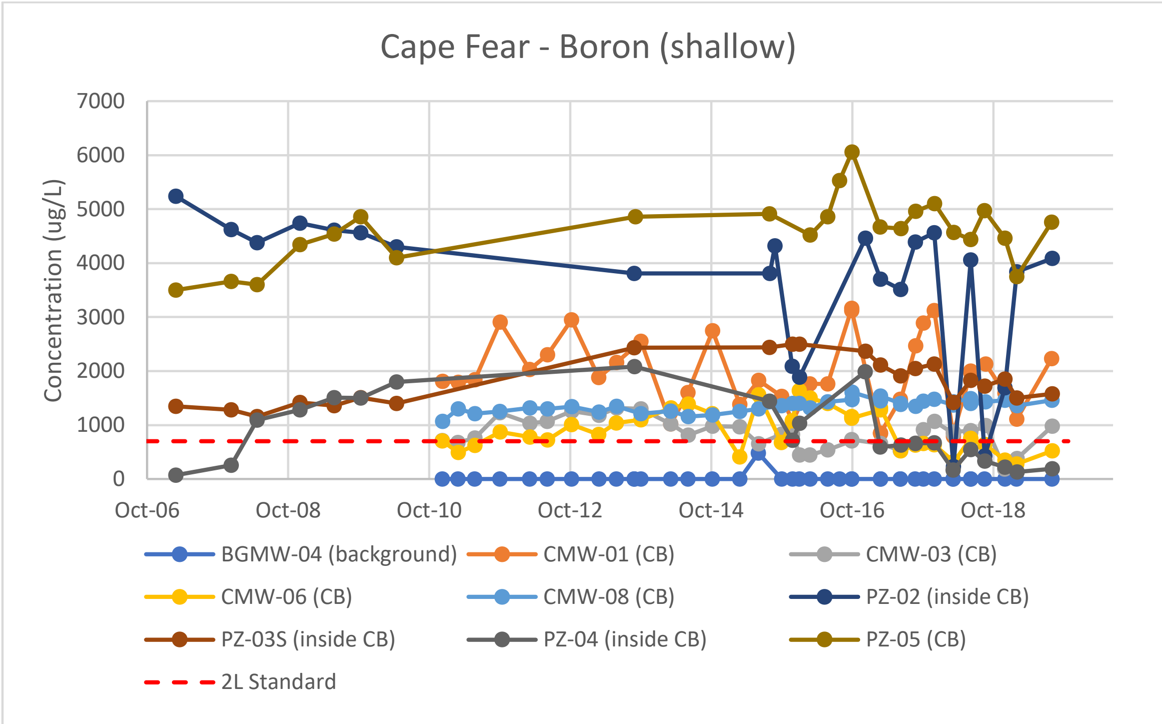
Site maps showing the well locations and groundwater flow are included as Hart Exhibit 44A and an Excel spreadsheet of groundwater data for the facility is included as Hart Exhibit 44B.

<u>Details</u>

Groundwater monitoring at the Cape Fear facility began in 2007 with the sampling of wells installed along the waste boundary of the 1985 ash basin, and within the compliance boundary (CB). Wells PZ-1 through PZ-5 were installed in the shallow aquifer (referred to as the surficial aquifer) and PZ-3D was screened in bedrock. Iron and manganese were detected above the 2L

Standard from 2007 through 2018 or 2019 in PZ-1 (inside CB), PZ-2 (inside CB), and PZ-4 (inside CB), and manganese was detected above the 2L Standard in PZ-5 (CB). PZ-5 was installed at the compliance boundary. Cobalt was detected above the IMAC in PZ-1, PZ-2, PZ-4, and PZ-5 between 2015 and 2019. Boron was detected above the 2L Standard from 2007 through 2019 in PZ-2, PZ-3S (inside CB), and PZ-5 (CB) between 2007 and 2019, and concentrations in PZ-4 (inside CB) exceeded the 2L Standard between 2008 and 2016, but decreased below the standard in more recent years. Total dissolved solids and sulfate in PZ-1 (inside CB) and total dissolved solids in PZ-3S (inside CB) exceeded the 2L Standard between 2007 and 2019, and total dissolved solids and sulfate were detected above the 2L Standard in select early sampling events ranging between 2007 and 2016 in PZ-2, PZ-4, and PZ-5.

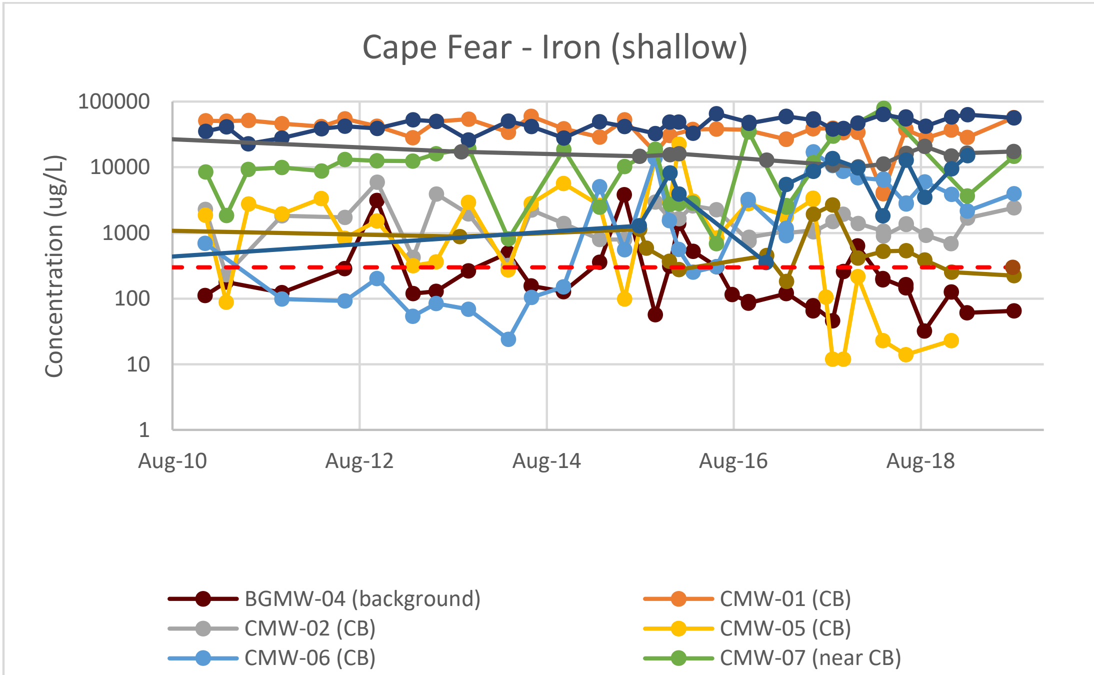
In bedrock well PZ-3D, manganese was detected at concentrations exceeding the 2L Standard between 2007 and 2019. No background wells were installed for comparison of groundwater concentrations to naturally occurring concentrations prior to 2010, however early concentrations were retroactively compared to the BTVs established in 2017. Sulfate, total dissolved solids, iron, cobalt, and manganese have BTVs exceeding the 2L Standards or IMAC within the shallow and bedrocks aquifers; however, with the exception of cobalt, concentrations in the waste boundary wells exceeded the BTVs. Additionally, the BTVs for boron did not exceed the 2L Standard and concentrations as early as 2007 were detected well above the 2L Standard. A graph showing the concentrations of boron in site wells compared to background wells (discussed below) is included below.

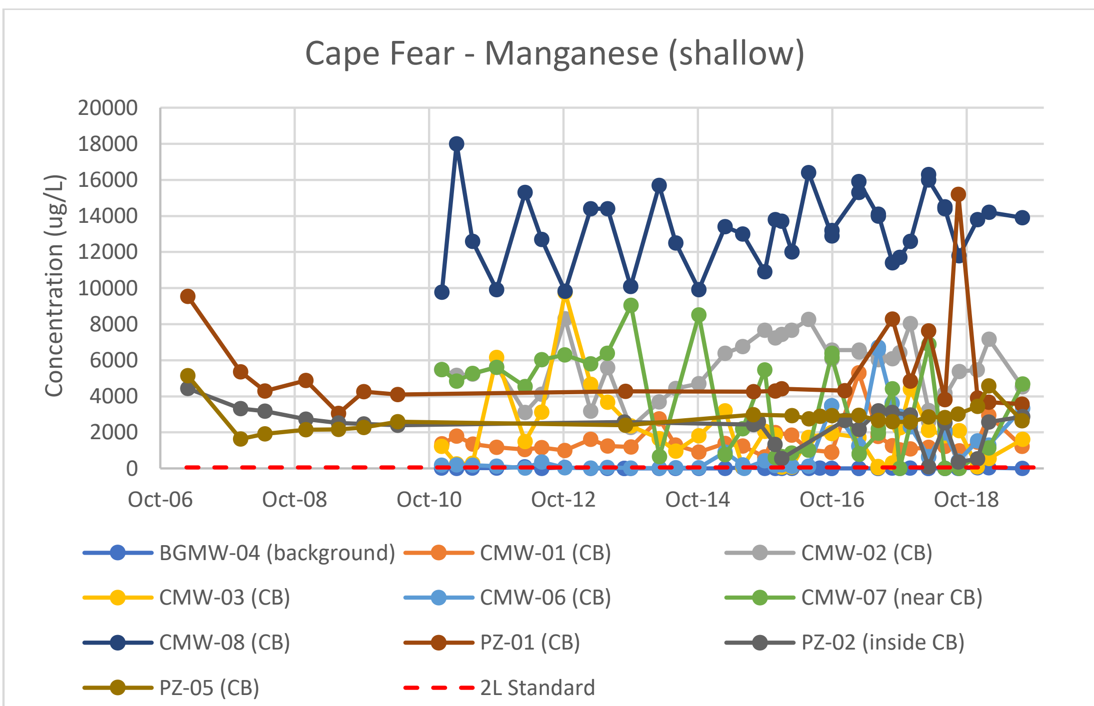


In 2010, monitoring along the compliance boundary was requested by DEQ. Background well BGMW-4 was installed in the shallow aquifer and BGTMW-4 was installed in bedrock near the northern property boundary and outside of the compliance boundary. With the exception of vanadium detected between 2015 and 2019, no compounds were detected above 2L or IMAC Standards in BGMW-4 (background). Manganese was detected at concentrations slightly above the 2L Standard in BGTMW-4 (background) from 2010 through 2019, and intermittent concentrations of vanadium were detected above the IMAC.

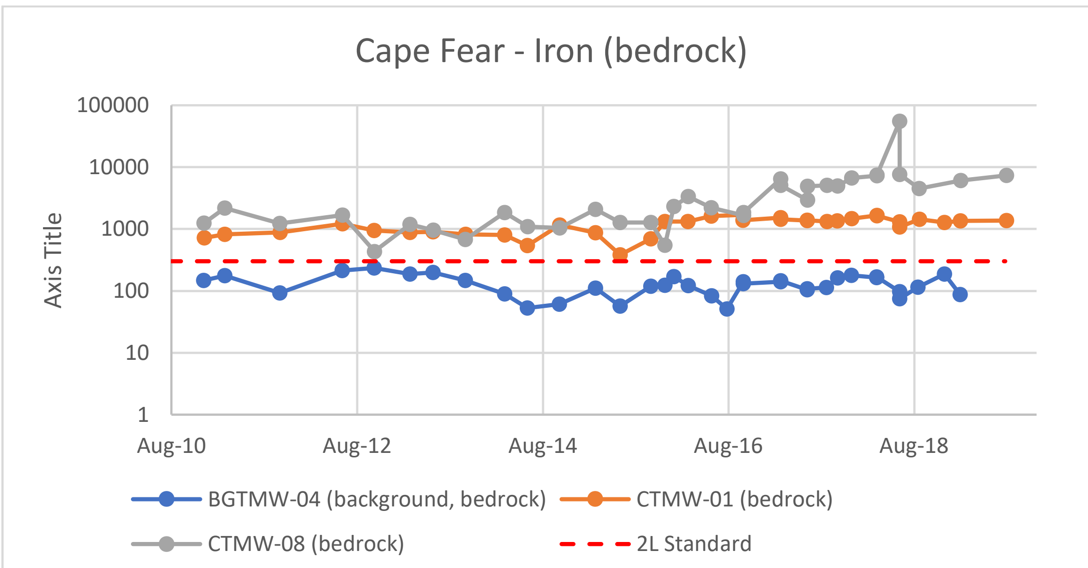
CMW-1/CTMW-1 through CMW-8/CTMW-8 were installed at locations at or near the compliance boundary in 2010. CMW-1/CTMW-1, CMW-2/CTMW-2, CMW-7/CTMW-7, and CMW-8/CTMW-8 were installed directly downgradient of the ash basins. In the shallow aquifer, iron, manganese, and boron were detected above the 2L Standard from 2010 through 2019 in CMW-1 (CB) and CMW-8 (CB). Iron, manganese, and sulfate were detected in CMW-2 (CB) from 2010 through 2019, total dissolved solids were detected above 2L Standards from 2010 through 2016, and cobalt and vanadium were detected above IMAC Standards from 2010 through 2019. In CMW-7 (near CB), iron and manganese were detected above the 2L Standards from 2010 through 2019 and cobalt and vanadium were detected above the IMAC from 2015 through 2019. In CMW-3 (near CB), located down to cross gradient of the 1956 ash basin, boron was detected above the 2L Standard for the majority of the sampling events between 2010 and 2019, manganese was detected exceeding the standard in each sampling event, and vanadium and cobalt were detected exceeding the IMACs in the majority of the sampling events completed between 2015 and 2019. In addition, selenium was detected above the 2L Standard from 2010 through 2014.

CMW-6 (CB) is located cross-gradient to the 1985 ash basin and concentrations of iron and manganese increased over time until they exceeded the 2L Standard in 2015. Boron concentrations exceeded the 2L Standard from 2011 through 2017 in CMW-6. In CMW-5 (CB), located along the northern compliance boundary of the 1985 ash basin, iron was detected above the 2L Standard from 2010 through 2019. Graphs depicting the iron and manganese concentrations in shallow wells compared to the background well are provided below. Please note the y-axis on the iron graph is shown with a logarithmic scale due to the high concentrations in some wells.





In bedrock wells CTMW-1 and CTMW-8, iron and manganese were detected above the 2L Standards from 2010 through 2019. Vanadium was detected above the IMAC from 2015 through 2019 in CTMW-2 (bedrock) and CTMW-7 (bedrock), and manganese was detected above the 2L Standards from 2010 through 2019 in CTMW-7. A graph depicting the iron concentrations in bedrock wells compared to background well BGTMW-04 is included below. Please note the y-axis is shown with a logarithmic scale because of the high levels in some wells.



In 2013, additional groundwater monitoring wells MW-9 through MW-14 were sampled. MW-9 (outside CB) was installed in bedrock along the eastern property boundary, well outside of the compliance boundary and indicated concentrations of iron and manganese above the 2L Standards and total dissolved solids above 2L Standards from 2015 through 2017. MW-10 (near CB) was installed along the northern compliance boundary and indicated concentrations of boron, sulfate, total dissolved solids, cobalt, iron, and manganese above the IMAC and 2L Standards from 2015 through 2019.

In 2017, BTVs were evaluated for the site. The background compliance wells BGMW-4 and BGTMW-4 were not used in the determination as it was noted that the concentrations could be impacted by upgradient sources. However, the BTVs requested to be used by DEP are suspect because they are higher than any concentrations detected in the actual site background wells. Nevertheless, concentrations of each compound discussed above were detected in sampling events exceeding the BTVs. As mentioned, the BTV for boron was below the 2L Standard and no elevated boron concentrations can be attributed to naturally occurring concentrations and therefore the exceedances indicate a violation of the 2L Standard.

VI. HF LEE ENERGY COMPLEX

Q. PLEASE PROVIDE A HISTORY OF COAL ASH BASINS AT THE PLANT.

A. The HF Lee facility historically stored CCR in three inactive ash basins, and the Active Ash Basin. Inactive Ash Basin 1 was operated from 1951 through 1962, and Inactive Ash Basin 2 operated from 1955 through 1962. The basins cover a combined 76 acres and an estimated total of approximately 650,000 cubic yards of CCR were placed in the basins. Inactive Ash Basin 3 operated from 1962 through 1980 and contains approximately 750,000 cubic yards of CCR in its 87-acre footprint. The inactive basins reportedly do not hold water.

The Active Ash Basin was operated from 1980 through 2012 and covers approximately 62 acres. The basin contains approximately 3.8 million cubic yards of CCR. According to the 2019 CAM report, DEP ceased placing CCR and other wastewaters in the Active Action Basin in 2019.

In addition to sluiced CCRs, the ash basins were also used for disposal of precipitator and preheater wash water, filter plant blowdown and wastewater, turbine system wastewater, cooling tower basin sludge, and low volume wastes.

Q. PLEASE DISCUSS WHEN DEP BECAME AWARE OF GROUNDWATER CONTAMINATION ASSOCIATED WITH THE COAL ASH BASINS AT THE FACILITY AND BRIEFLY DESCRIBE RESULTS OF GROUNDWATER ASSESSMENT AND MONITORING OVER TIME AT THE FACILITY.

A. A brief summary of groundwater contamination is provided in bullet format below, which is then described in greater detail in the paragraphs that follow.

Summary

- Voluntary groundwater monitoring began around the active ash basin in 2007 with monitoring wells MW-1 through MW-4. MW-1 is located along the northern waste boundary and MW-2 through MW-4 were installed downgradient near the compliance boundary. In the downgradient wells along the compliance boundary, boron, total dissolved solids, iron, and manganese were detected above the 2L Standards in 2007. No background well was installed at this time.
- Although the voluntary monitoring wells described above were near the compliance boundary, the wells were not included as compliance boundary

wells when additional monitoring was requested by DEQ in 2010. Concentrations in wells along the compliance boundary indicated exceedances of iron (up to 14,900 µg/L compared to the 2L Standard of 300 µg/L and later derived BTV of 414 µg/L), manganese (up to 1,000 µg/L compared to the 2L Standard of 50 µg/L and later-derived BTV of 838 µg/L), arsenic (up to 665 µg/L compared to the 2L Standard of 10 µg/L), and boron (up to 4,940 µg/L compared to the 2L Standard of 700 µg/L). Background wells BGMW-9 and BGMW-10 were also installed outside the compliance boundary to the north of the ash basin.

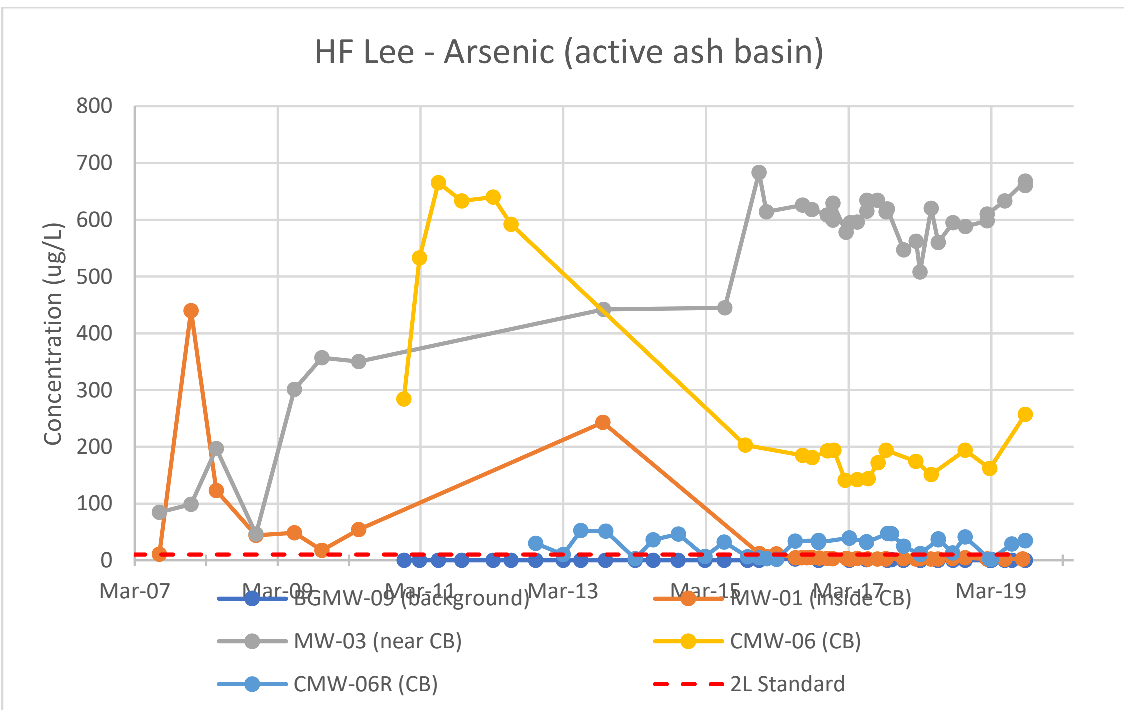
- Around the inactive ash basins, groundwater monitoring began in 2011. BW-1 was installed as a background well along the northeastern waste boundary, within the compliance boundary and was later found to be an insufficient background well. Concentrations along the downgradient compliance boundary indicated iron (up to 32,300 µg/L compared to the 2L Standard of 300 µg/L and later-derived BTV of 414 µg/L) and manganese (up to 3,080 µg/L compared to the 2L Standard of 50 µg/L and later-derived BTV of 838 µg/L) above standards.
- Despite knowledge of groundwater impacts near the compliance boundary in 2007 and evidence of more widespread detections at the compliance boundary in 2010, DEP did not perform mitigation activities to address the groundwater impacts, including in those ponds that had not been used in a long time.

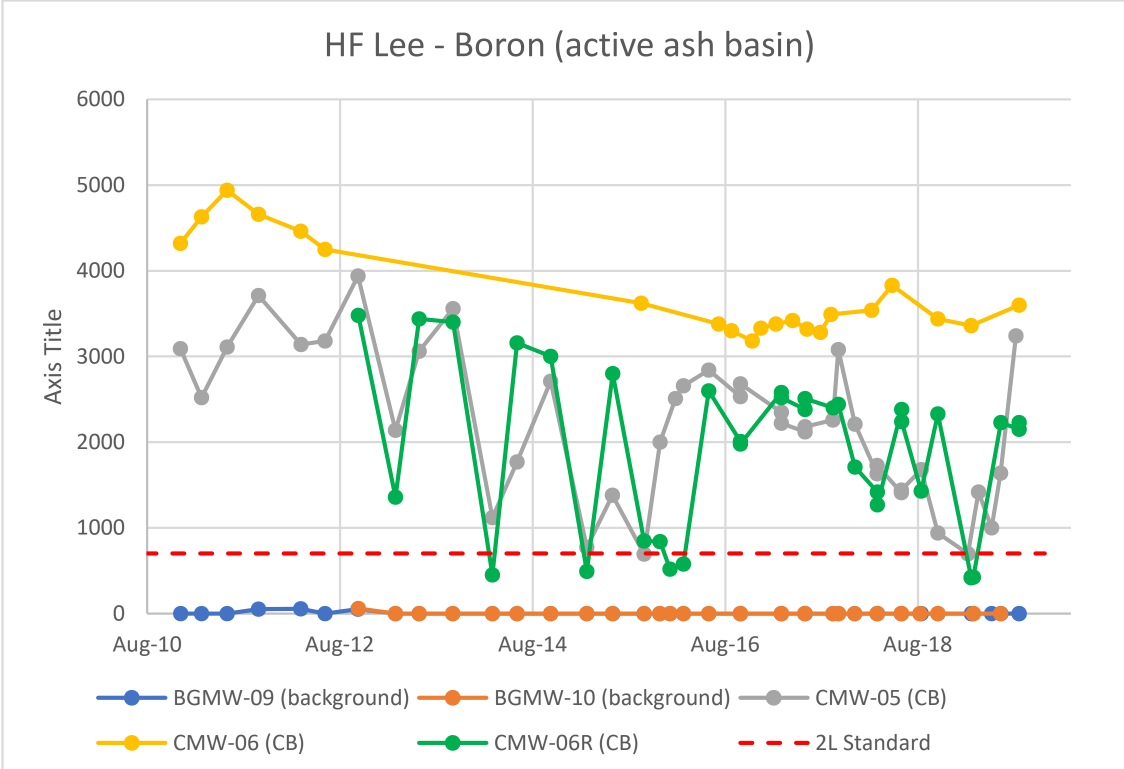
Site maps showing the well locations and groundwater flow are included as Hart Exhibit 45A and an Excel spreadsheet of groundwater data for the facility is included as Hart Exhibit 45B.

Details

Groundwater assessment at the HF Lee facility began in 2007 when wells MW-1 through MW-4 were installed at the Active Ash Basin. MW-1 is located on the northern waste boundary of the active ash basin, and MW-2 through MW-4 are near or potentially at the compliance boundary (CB) on the downgradient side of the ash basin. Manganese was detected above the 2L Standard from 2007 through 2019 and cobalt was detected above the IMAC from 2015 through 2019 in MW-1 (inside CB). Arsenic and iron were detected in MW-1 above the 2L Standards from 2007 through 2016. In MW-2 (near CB) through MW-4 (near CB), manganese was detected above the 2L Standard from 2007 through 2019 (note that MW-4 was only sampled through 2013) and iron in MW-3 (near CB) and MW-4 was detected above the 2L Standard over a similar time period. In MW-2, iron was consistently above the 2L Standard from 2007 through 2013, when it decreased below the 2L Standard. In MW-3, boron, total dissolved solids, and arsenic were detected above the 2L Standards from 2007 through 2019, and cobalt was detected above the 2L Standard from 2015 (the first year it was included as an analyte) through 2019.

In 2010, additional wells along the compliance boundary of the Active Ash Basin were installed. Background wells BGMW-9 and BGMW-10 were installed to the north of the active ash basin on the compliance boundary. In both background wells, iron and manganese were detected above the 2L Standard from 2010 through 2019 and cobalt was detected above the IMAC from 2015 through 2019. CMW-5, CMW-8, and CMW-10 were installed along the downgradient compliance boundary. Iron and manganese were detected in each well similar to background concentrations; however, boron was detected in CMW-5 (CB) at concentrations well above the 2L Standard from 2010 through 2019. CMW-6/6R (CB) was installed at the eastern compliance boundary, cross-gradient of the ash basin and indicated elevated concentrations of boron and arsenic above the 2L Standards from 2010 through 2019. Graphs depicting the arsenic and boron concentrations in downgradient wells compared to the background wells at the Active Ash Basin are included below.





In CMW-6R (CB), cobalt was also detected above the IMAC from 2015 through 2019, however concentrations were consistent with those detected in background groundwater.

At the inactive ash basins, groundwater monitoring started in 2011 at the request of DEQ. The well designated as the background well (BW-1) was installed to the northwest of the Inactive Ash Basin 1, but within the compliance boundary. Based on the proximity to the former ash basin, the well is not considered to be an accurate representation of background concentrations. During the establishment of BTVs in the 2015 Corrective Action Plan prepared for the HF Lee facility, none of the background wells established during the original compliance monitoring of the active or inactive ash basins were used to determine the BTVs for the facility in 2017. In BW-1 (ineffective background), concentrations of iron and manganese were elevated above 2L Standards from 2012 through 2019 and cobalt and boron were above 2L Standards from 2015 through 2019. In downgradient compliance wells CW-1 (CB) through CW-4 (CB), iron, manganese, and cobalt were elevated above 2L Standards for each well during each sampling event in which they were included as analytes between 2011 and 2019.

The provisional BTV concentrations for iron, manganese, and cobalt were above the 2L and IMAC, however concentrations in the surficial wells downgradient of the inactive ash basins exceeded the BTVs and indicate a violation of the 2L Standards.

VII. MAYO STEAM ELECTRIC PLANT

Q. PLEASE PROVIDE A HISTORY OF COAL ASH BASINS AT THE PLANT.

A. The active ash basin at the Mayo facility was constructed in 1982 to receive CCR material from the plant which began operation in 1983. The basin is approximately 144 acres and received sluiced ash from 1982 until 2019. A dry fly ash handling system was installed in 2013 and upgraded in 2016, and dry bottom ash handling was added in 2014. However, DEP reports indicate that ash is still sluiced to the basin in the event that the dry ash handling system is down, and in 2015 approximately 90% of the generated CCR was dry handled. The dry ash was hauled to the Roxboro plant from 2013 until the onsite monofill was constructed at Mayo in 2014. The monofill is approximately 31 acres and is lined. The basin is estimated to contain approximately 5.5 million cubic yards of CCRs.

In 2009, a flush pond and settling pond were constructed in the footprint of the ash basin to manage the sludge produced from the scrubber system. The blowdown stream produced by the flue gas desulfurization (FGD) system is pumped to the settling pond.

In addition to sluiced CCR, the Active Ash Basin also received other wastewaters including coal pile runoff water, various stormwater flows, sewage treatment plant discharges, cooling tower blowdown, boiler blowdown, air preheater wash water, boiler wash water, precipitator wash, oily waste treatment, wastes/backwash water from water treatment processes, plant area washdown water, and the equipment heat exchanger water.

Q. PLEASE DISCUSS WHEN DEP BECAME AWARE OF GROUNDWATER CONTAMINATION ASSOCIATED WITH THE COAL ASH BASINS AT THE FACILITY AND BRIEFLY DESCRIBE RESULTS OF GROUNDWATER ASSESSMENT AND MONITORING OVER TIME AT THE FACILITY.

A. A brief summary of groundwater contamination is provided in bullet format below, which is then described in greater detail in the paragraphs that follow.

<u>Summary</u>

- DEP began voluntary groundwater monitoring at the Mayo facility in 2008. Monitoring wells MW-2 through MW-4 were installed between the compliance and waste boundaries downgradient of the ash basin.

Background well BG-1 was installed along the compliance boundary to the southwest and upgradient of the ash basin and was screened in bedrock. Manganese and iron were detected above 2L Standards in the downgradient wells but because of anomalously high concentrations in the background well in early monitoring which were not confirmed in later sampling, the concentrations were not substantially higher.

- In 2010, additional groundwater monitoring wells were requested by DEQ and wells CW-1 through CW-6 were installed along the compliance boundary cross-gradient and downgradient of the ash basin. Background well BG-2 was also installed outside of the compliance boundary to the southwest of the ash basin to establish background concentrations in the transition zone aquifer. At the compliance boundary, the following compounds were detected above the 2L Standard or IMAC and background concentrations: boron (up to 1,060 µg/L compared to 2L Standard of 700 µg/L), manganese (up to 1,020 µg/L compared to the 2L Standard of 50 µg/L and later-derived BTV of 298 µg/L), and total dissolved (up to 560 µg/L compared to 2L Standard of 500 µg/L).
- Concentrations of boron in downgradient wells increased over time until they were above the 2L Standards in the 2014 to 2015 timeframe. The increase may have been related to the FGD scrubber installed in 2009. Regardless of the source, the increases were an indication that the source of the groundwater impacts needed to be addressed as required by the 2L Rules.

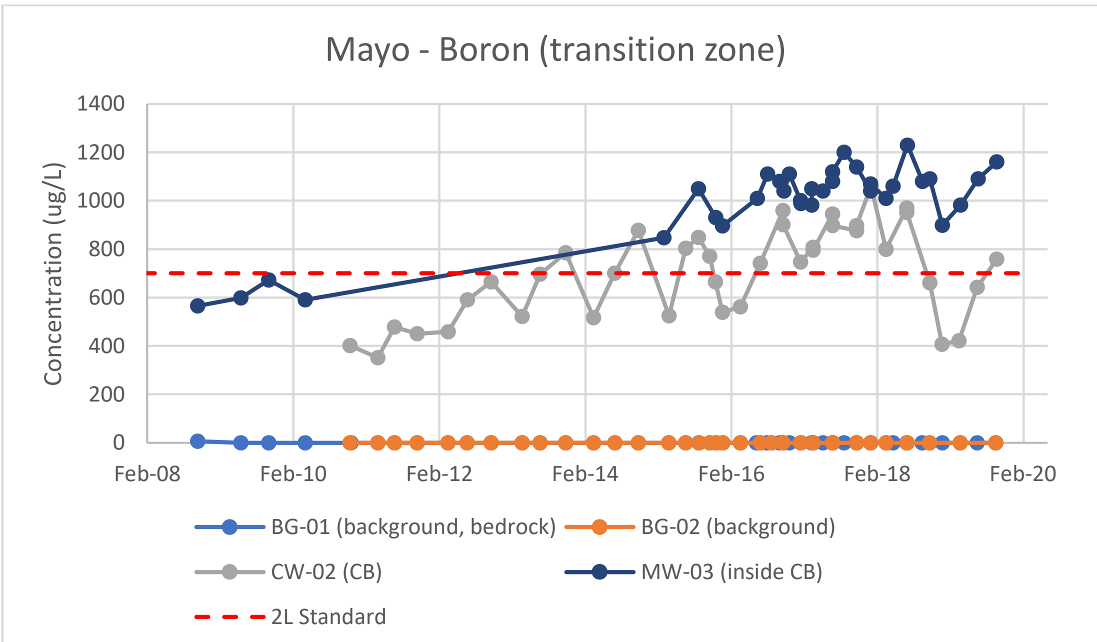
- In 2013, the facility converted to dry fly ash handling, and in 2014, the facility converted to dry bottom ash handling. However, some limited sluicing of ash occurred until 2019. The conversion to fly ash handling was a reasonably good step to minimize the addition of coal ash contaminants to the basins.

Site maps showing the well locations and groundwater flow are included as Hart Exhibit 46A and an Excel spreadsheet of groundwater data for the facility is included as Hart Exhibit 46B.

Details

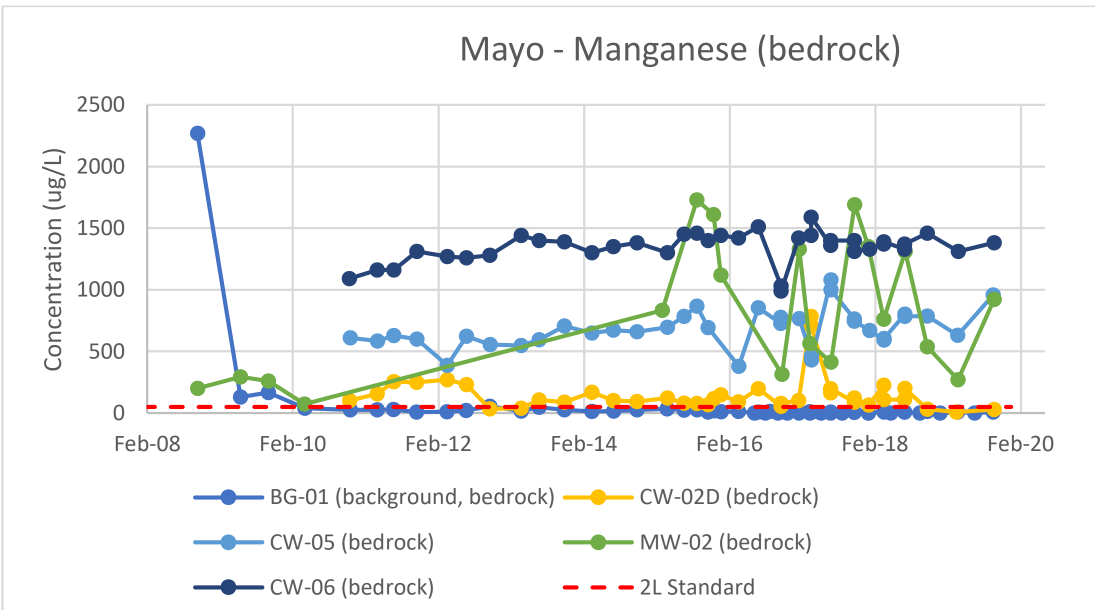
Groundwater monitoring at the Mayo facility began in 2008. Background well BG-1 was installed to the southwest and upgradient of the ash basin and is screened in the bedrock zone slightly outside the compliance boundary (CB). MW-2, MW-3, and MW-4 were installed on the downgradient side of the ash basin within the compliance boundary. Manganese and iron were detected above 2L Standards in the downgradient wells in 2008 through 2010 but because of anomalously high concentrations in background well BG-1 in early monitoring which were not confirmed in later sampling, the concentrations were not substantially higher. However, subsequent monitoring of these wells conducted in 2015 (after sampling of the wells resumed), confirmed that manganese and/or iron were present in these wells above background and 2L Standards. MW-2 (bedrock) and MW-4 (bedrock) are installed in bedrock and compliance boundaries do not apply to contamination in the bedrock; therefore, an exceedances of the applicable standards is a de facto violation of the 2L Rules. When cobalt was added as an analyte in 2015, it was detected above background and the 2L Standard in MW-2 (bedrock).

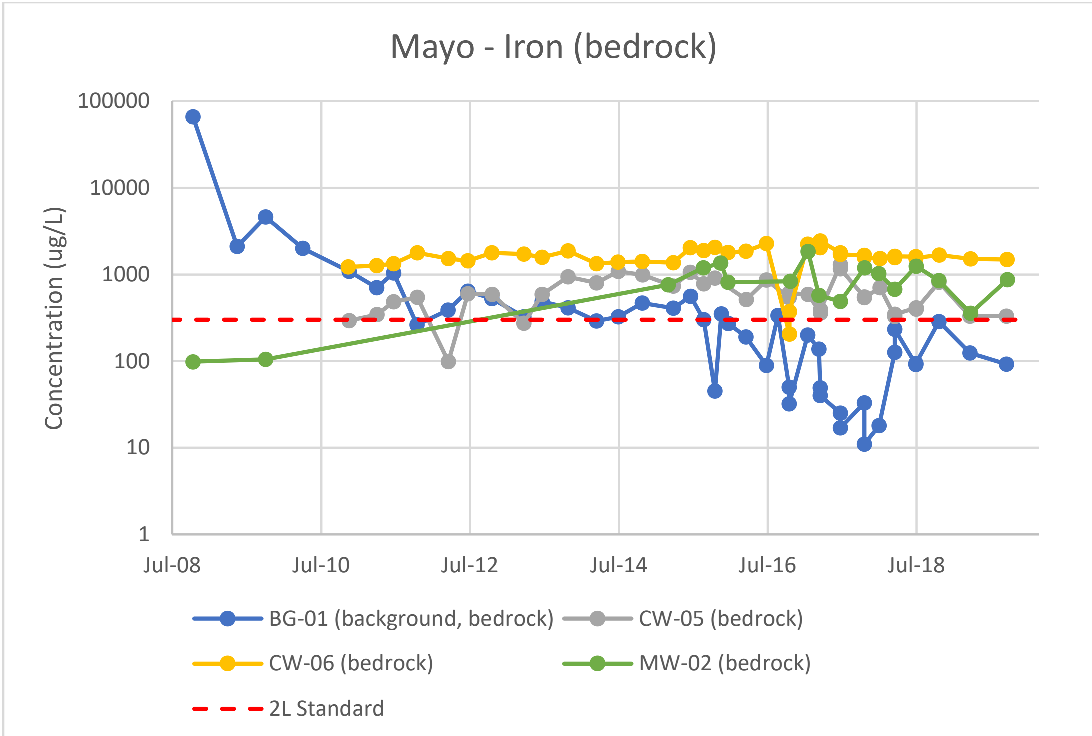
When initially sampled in 2008 to 2010, boron was detected below the 2L Standard in MW-3 (inside CB), but was above the 2L Standard when sampling of the well resumed in 2015. A graph showing boron concentrations over time in select wells is included below.



As indicated in the graph above, boron concentrations increased over time in well MW-3 (inside CB) and compliance well CW-2 (near CB) until they were above the 2L Standard. An FGD scrubber was added to the Mayo facility in 2009 which may be the source of the increased boron concentrations.

At the request of DEQ, compliance boundary wells were installed and sampled at the site in 2010. Wells CW-1 through CW-5 were installed along the compliance boundary and cross-gradient to downgradient of the ash basin. BG-2 was installed on the upgradient side of the ash basin outside of the compliance boundary to further evaluate background concentrations. Wells CW-2D, CW-5, and CW-6 are all screened in the bedrock zone and indicated concentrations of manganese exceeding the 2L Standard and background from 2010 through 2019. Iron was also detected above the 2L Standard in CW-5 (bedrock) and CW-6 (bedrock) during that period, and total dissolved solids was detected above the 2L Standard between 2012 and 2019 in CW-6. Graphs depicting the manganese and iron concentrations in downgradient bedrock wells compared to the background concentrations in the bedrock background well are included below. Please note the y-axis on the iron graph is a logarithmic scale due to high concentrations in some wells.





Background wells BG-1 and BG-2 were included in the establishment of background threshold values (BTVs) for the site in 2017. The BTVs established for iron, manganese, vanadium, and cobalt were above the 2L Standards or IMAC for each compound, however concentrations detected in some site wells were in exceedance of the current BTVs. The BTVs for boron and total dissolved solids are below the established 2L Standards and therefore the exceedances cannot be attributed to naturally occurring concentrations and indicate a violation of the 2L Standards.

VIII. ROBINSON STATION

Q. PLEASE PROVIDE A HISTORY OF COAL ASH BASINS AT THE PLANT.

A. The Robinson facility began operation in 1960. In the mid-1970s, the unnamed tributary of Black Creek was dammed and the ash basin was constructed. The ash basin at the Robinson site is approximately 72 acres and is comprised of the 49-acre basin and a 23-acre dry storage area along the western side of the basin. The basin operated as an ash disposal location from the mid-1970s until sluicing ceased in October 2012 as a result of retirement of the facility. The ash basin does occasionally receive wastewater from the adjacent combustion turbine facility's oil/water separator. The estimated cumulative volume of ash in the basin is approximately 2.4 million cubic yards.

In 2015, DEP entered into a Consent Agreement with DHEC that requires excavating the CCR at the Robinson facility.

Q: PLEASE DISCUSS WHEN DEP BECAME AWARE OF GROUNDWATER CONTAMINATION ASSOCIATED WITH THE COAL ASH BASINS AT THE FACILITY AND BRIEFLY DESCRIBE RESULTS OF GROUNDWATER ASSESSMENT AND MONITORING OVER TIME AT THE FACILITY.

A brief summary of groundwater contamination is provided in bullet format below, which is then described in greater detail in the paragraphs that follow.

<u>Summary</u>

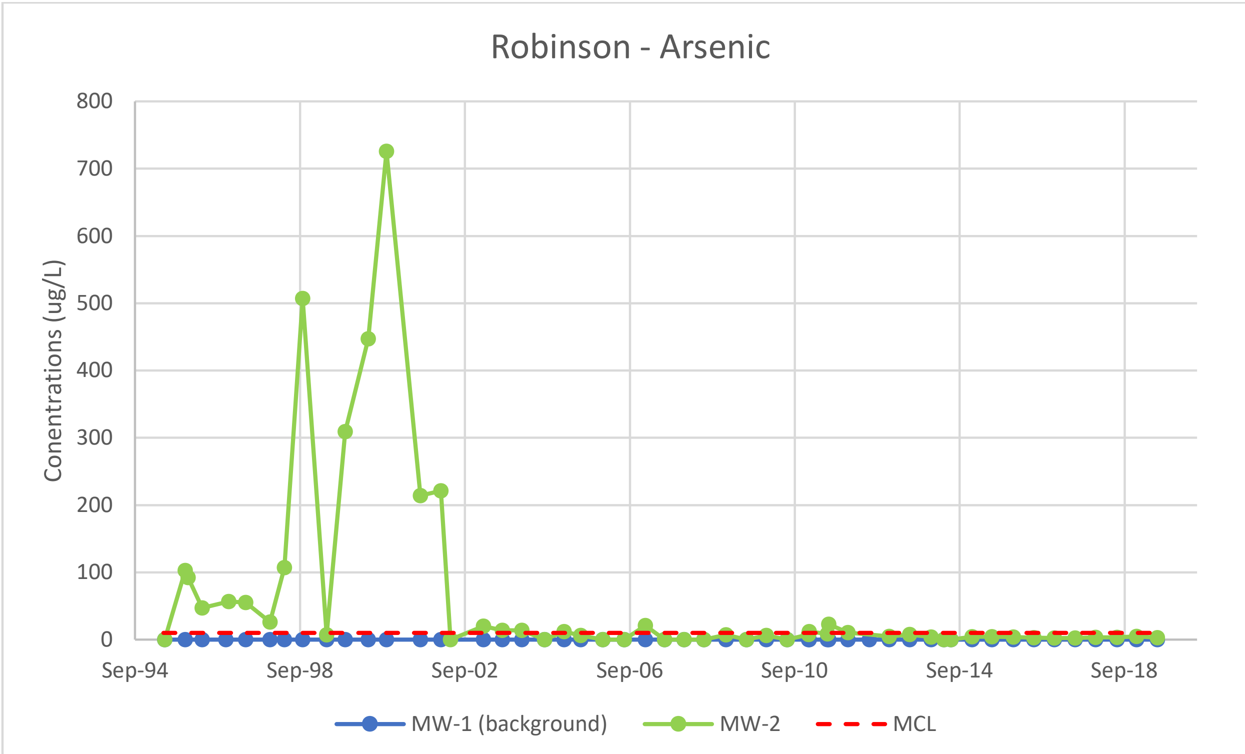
- Groundwater monitoring began at the ash basin in 1995. Groundwater monitoring well MW-1 is located upgradient of the ash basin and MW-2 and MW-3 are downgradient of the ash basin. Arsenic was detected in the downgradient well MW-2 at concentrations up to 507 µg/L compared to the MCL of 50 µg/L at the time (the arsenic MCL was changed in 2001 to 10 µg/L). The concentrations decreased below the MCL by 2012. Arsenic was not detected in the background well above detection limits so the MCL standard applies. In 2014, the wells were re-installed because of lack of water in the wells during certain sampling events.

- Additional downgradient monitoring wells were sampled in 2014 which indicated arsenic (up to 1,100 µg/L versus the MCL of 10 µg/L), iron (up to 10,700 versus MCL of 300 µg/L), and manganese (up to 1,150 µg/L versus the MCL of 50 µg/L) above the MCLs and above the background concentrations in the wells installed within the ash basin and/or downgradient of the ash basin.

Site maps showing the well locations and groundwater flow are included as Hart Exhibit 47A and an Excel spreadsheet of groundwater data for the facility is included as Hart Exhibit 47B.

Details

Groundwater monitoring began at the Robinson facility in 1995 with one background well (MW-1) installed upgradient of the ash basin and two monitoring wells (MW-2 and MW-3) downgradient of the basin. Monitoring well MW-4 was installed downgradient of the Robinson plant and a 1960 fill area. The wells were sampled for arsenic, cadmium, sulfate, and total dissolved solids as early as 1995 and zinc was added as an analyte in 1997. In 2007, chromium and copper were added as analytes and cadmium (which was originally included in sampling from 1995 through 1997) was again included as an analyte in 2007. No exceedances were detected above the MCLs in the background well MW-1. In MW-2, arsenic was above the MCLs primarily from 1997 through 2005 but decreased below the MCL by 2012. Sulfate and total dissolved solids were detected above the MCLs in MW-4 from 2015 through 2018 and 2015 through 2017, respectively. A graph showing arsenic concentrations in MW-2 versus the background well is included below.



Wells MW-5 through MW-7 were installed downgradient of the ash basin and were first sampled in 2014. Arsenic was detected in MW-7 from 2014 through 2019 at concentrations up to 180 µg/L exceeding the MCL of 10 µg/L. Monitoring wells MW-101D and MW-107S/D through MW-115S/D were sampled once in 2014. MW-101D was installed upgradient of the ash basin in the vicinity of monitoring well MW-1. Arsenic (up to 1,100 µg/L), iron (up to 10,700 versus MCL of 300 µg/L) and manganese (up to 1,150 µg/L versus the MCL of 50 µg/L) were detected above the MCLs and above the background concentrations in the wells installed within the ash basin and/or downgradient of the ash basin in 2014.

IX. ROXBORO STEAM ELECTRIC PLANT

Q. PLEASE PROVIDE A HISTORY OF COAL ASH BASINS AT THE PLANT.

A. The oldest ash basin at the Roxboro facility, known as the East Ash Basin, was constructed in 1963 and ash production at the facility began in 1966. The East Ash Basin was vertically expanded in 1973. In 1983, the East Ash Basin reached capacity and was taken out of service, although some recent NPDES permits indicate that water from the West Ash Basin and FGD scrubber wastewater may be discharged to the East Ash Basin. The East Ash Basin is approximately 71 acres, and the cumulative volume of CCRs placed in the East Ash Basin is approximately 6 million cubic yards. To reduce concentrations of selenium in Hyco Lake where the ash pond discharged, the facility converted to dry fly ash handling in 1990. According to the facility's NPDES permit, fly ash was dry handled and only in the event that the dry handling system was out of service would the fly ash be sluiced with the bottom ash to the basins. The Roxboro Industrial Landfill was constructed within the East Ash Basin as part of the conversion to dry ash handling and was first used in 1988.

In 1973, the West Ash Basin was constructed by placing a dam across Sargents Creek. Fly ash and bottom ash were sluiced to the West Ash Basin until 1990 when the facility converted to dry fly ash handling. Sluicing of bottom ash to the West Ash Basin concluded in April 2019 when the dry bottom ash system became operational. The West Ash Basin is approximately 225 acres and contains an estimated 11 million cubic yards of CCRs.

Three ponds within the area of the West Ash Basin are used for the treatment of FGD wastewaters and were constructed in 2008 to 2011. These three ponds are the West FGD Settling, the East FGD Settling Pond, and the FGD Forward Flush Pond. The West and East FGD Settling Ponds receive FGD blowdown. The FGD Forward Flush Pond receives inflow from the back-flush of the bioreactor. The inflow is treated and released from the West and East FGD Settling to the West Ash Basin. The three FGD ponds contain approximately 200,000 tons of CCR.

In addition to sluiced CCRs, the ash basins also received ash landfill leachate and runoff, stormwater, sump discharges, low volume wastewaters, cooling tower blowdown, coal mill rejects and pyrites, and treated sanitary sewage effluent.

Q. PLEASE DISCUSS WHEN DEP BECAME AWARE OF GROUNDWATER CONTAMINATION ASSOCIATED WITH THE COAL ASH BASINS AT THE FACILITY AND BRIEFLY DESCRIBE RESULTS OF GROUNDWATER ASSESSMENT AND MONITORING OVER TIME AT THE FACILITY.

A. A brief summary of groundwater contamination is provided in bullet format below, which is then described in greater detail in the paragraphs that follow.

<u>Summary</u>

- Groundwater monitoring was first performed at the Roxboro site in 2000. Monitoring wells MW-1 and MW-2 were installed downgradient of the Western Ash Basin along the waste boundary. Iron was detected above the

2L Standard in MW-1 and MW-2 as early as 2000, although concentrations generally decreased with time. No background wells were installed at that time.

- In 2002, groundwater monitoring wells GMW-6 through GMW-11 were installed around the landfill and the East Ash Basin which indicated exceedances of 2L Standards for sulfate, total dissolved solids, iron, manganese, and selenium. Wells GMW-7 and GMW-8 are installed in bedrock and indicated 2L exceedances of iron, chromium, manganese, total dissolved solids, and/or sulfate as early as 2002. The compliance boundary does not apply to bedrock groundwater impacts in accordance with the 2L Rules; therefore, an exceedance of the standard is a de facto violation of the 2L Rules.
- Boron was included as an analyte in 2009 and exceeded the 2L Standards in multiple wells at that time, including bedrock wells. Concentrations in several wells indicated increases in concentrations in boron and other compounds over time, potentially as a result of the FGD scrubber wastewater system installed in the 2008 to 2011 timeframe.
- Groundwater monitoring at the compliance boundary began in 2010 with the installation of background well BG-1 and cross-gradient and downgradient wells CW-1 through CW-5. In the shallow aquifer, sulfate (up to 873 µg/L compared to 2L Standard of 250 µg/L) and total dissolved solids (up to 1,510 µg/L compared to the 2L Standard of 500 µg/L and background value of 540 µg/L) were detected above the 2L Standards.

- Despite evidence of groundwater impacts in bedrock as early as 2002 and at the compliance boundary in 2010, DEP did not perform any additional actions to mitigate the groundwater impacts. Further, boron and selenium concentrations have increased with time in bedrock indicating ongoing groundwater degradation.

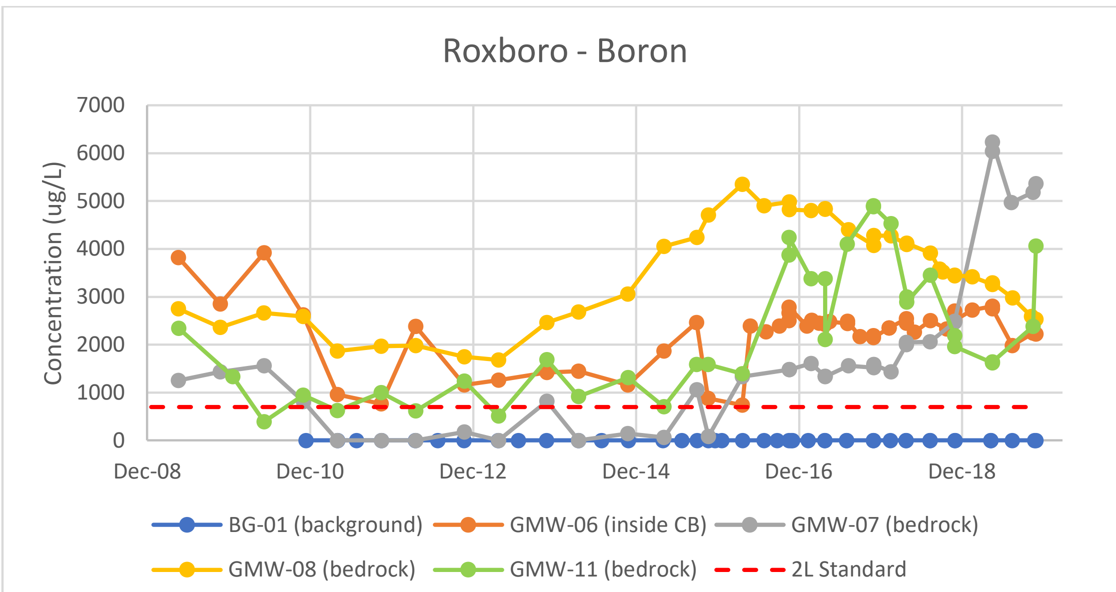
Site maps showing the well locations and groundwater flow are included as Hart Exhibit 48A and an Excel spreadsheet of groundwater data for the facility is included as Hart Exhibit 48B.

Details

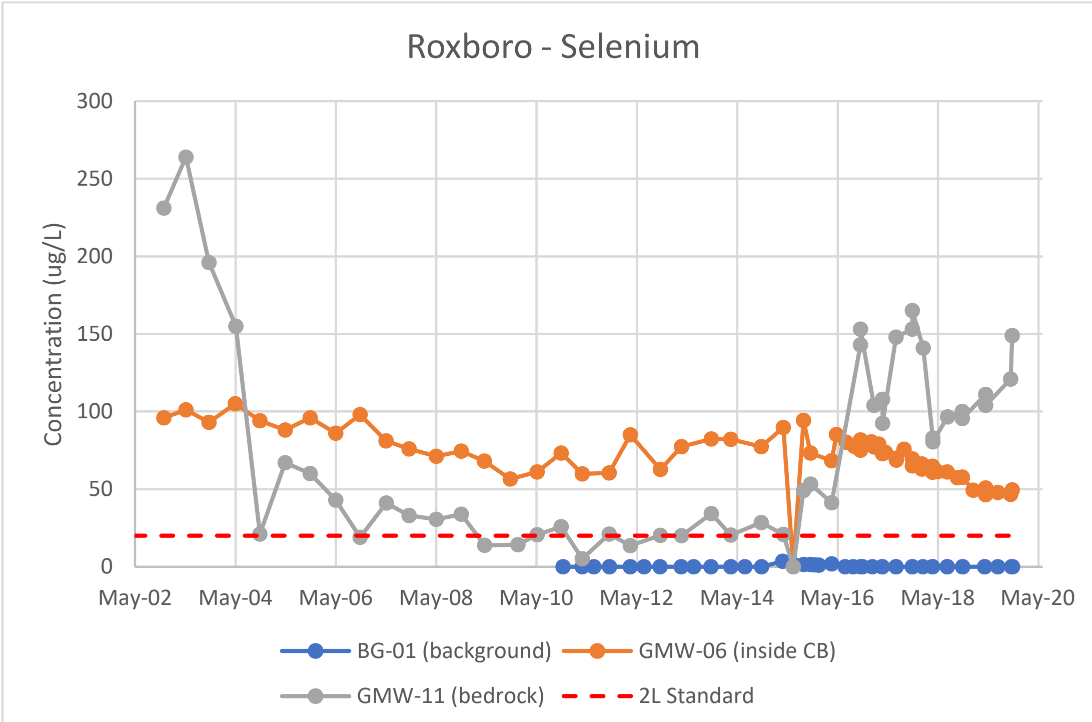
Groundwater monitoring at the Roxboro facility began in 2000 at which time monitoring wells MW-1 (inside CB) and MW-2 (inside CB) were sampled. Both wells are located to the north and downgradient of the West Ash Basin. No background wells were installed at that time. Iron was detected above the 2L Standard at that time, but generally decreased with time. Manganese and vanadium were first included as sample analytes in 2015 at which time the concentrations exceeded the applicable standards. Iron was detected in MW-2 (inside CB) at concentrations consistently above the 2L Standard between 2000 and 2007. In 2016 and 2017, concentrations of boron, chloride, and total dissolved solids increased to concentrations exceeding the 2L Standards for each compound.

Monitoring wells GMW-6 through GMW-11 were first sampled in 2002. The wells were installed around the East Ash Basin and the landfill within the boundary of the East Ash Basin. GMW-6 (inside CB) was located on the downgradient side of the East Ash Basin and, from 2002 through 2019, boron, sulfate, total dissolved solids, and selenium were detected at concentrations exceeding the 2L Standards. Iron and manganese were originally detected above 2L Standards from 2002 through 2010, but concentrations decreased below the 2L Standards at that time.

GMW-7 through GMW-11 were installed as bedrock monitoring wells. Concentrations of boron and total dissolved solids showed an increasing trend in GMW-7 (bedrock) from 2015 to 2019 and were above 2L Standards. A graph showing boron concentrations is shown below.



Chromium and iron were also detected above 2L Standards in GMW-7 (bedrock) between 2004 and 2010, but decreased below the 2L Standards at that time. In GMW-8 (bedrock), sulfate from 2003, total dissolved solids from 2002, and boron from 2009 (when it was first analyzed) were detected above 2L Standards until 2019. In GMW-11 (bedrock), selenium was detected above the 2L Standards from 2002 to 2019, and boron was detected from 2009 (when it was first analyzed) to 2019 above the 2L Standard. A graph showing selenium concentrations with time is shown below.



As indicated above, selenium concentrations in GMW-11 (bedrock) decreased in the 2002 to 2006 timeframe, remained relatively stable until 2015, and have been increasing since that time.

In 2010, groundwater monitoring along the compliance boundary was requested by DEQ. Background well BG-1 was installed southwest and upgradient of the ash basin. Iron was detected in the background monitoring well from 2010 to 2016 at concentrations exceeding the 2L Standard, and vanadium was detected at concentrations above the IMAC from 2015 through 2019. With the exception of intermittent concentrations of chromium slightly above the 2L Standard, no other compounds were detected above the 2L Standards or IMACs in the background well.

Wells installed downgradient of the ash basin along the compliance boundary included CW-2 (CB), CW-2D (bedrock), and CW-5 (CB). Concentrations of sulfate and total dissolved solids exceeded the 2L Standards and background concentrations in CW-5 (CB) from 2010 through 2015 and 2010 to 2017, respectively. The other wells along the compliance boundary are not downgradient of the ash basins and did not indicate concentrations significantly above 2L or IMAC Standards.

No background well was installed at the site until 2010 and BTVs were established in 2017. The established BTVs for iron, manganese, total dissolved solids and vanadium are above the 2L and IMAC Standards for the compounds. Concentrations detected at the compliance boundary exceeded the BTVs in at least one sample for the compounds, although not consistently. The established BTVs for sulfate are below the 2L Standard and exceedances are not attributable to naturally occurring concentrations.

X. L.V. SUTTON ENERGY COMPLEX

Q. PLEASE PROVIDE A HISTORY OF COAL ASH BASINS AT THE PLANT.

A. The ash generated from site operations was originally placed in the former ash disposal area (FADA; also called the Lay of Land Area) from 1954 to 1972. In 1971, the Old Ash Basin (aka, the 1971 Ash Basin) was constructed as a collection area for sluiced fly and bottom ash. In 1983, the storage capacity of the Old Ash Basin was increased by raising its dikes. The Old Ash Basin was apparently operated until 1985, although it was temporarily used again in 2011 for repair work and ash removal. In 1984, the New Ash Basin (aka, the 1984 Basin) was constructed to the north of the Old Ash Basin. The New Ash Basin is lined with a 12-inch clay liner. An interior containment area was constructed in the New Ash Basin in 2006 to increase its storage capacity.

Combined, the Old and New Ash Basins contained a cumulative volume of 5.5 million cubic yards of CCRs. The Sutton facility was retired in 2013 and coal ash was no longer placed in the basins after that time. The coal fired power plant was demolished in 2017. A natural gas fired plant has operated at the site since 2013. CAMA designated the Sutton ash basins as "high risk" and required the closure of its ash basins by August 1, 2019. DEP began removal of coal ash from the basins in 2015 which was completed by 2019.

In addition to CCRs, wastes disposed in the ash basins included coal pile runoff, stormwater runoff from yard and plant, sludge from basins and sumps, boiler blowdown, drains from areas likely to contain oil-filled equipment or storage, air preheater and precipitator wash water, and chemical metal cleaning wastes. As discussed previously, there were groundwater contamination concerns associated with the Sutton facility in the 1970s, and groundwater monitoring conducted in the mid-1980s confirmed groundwater impacts at and beyond the compliance boundary. In 1987, DEQ issued a Notice of Non-Compliance for the Sutton facility based on the 2L exceedances of total dissolved solids and chloride at and beyond the compliance boundary (Hart Exhibit 24B). The sources of the contamination identified by DEQ were the intake canal, Lake Sutton, and the ash pond.

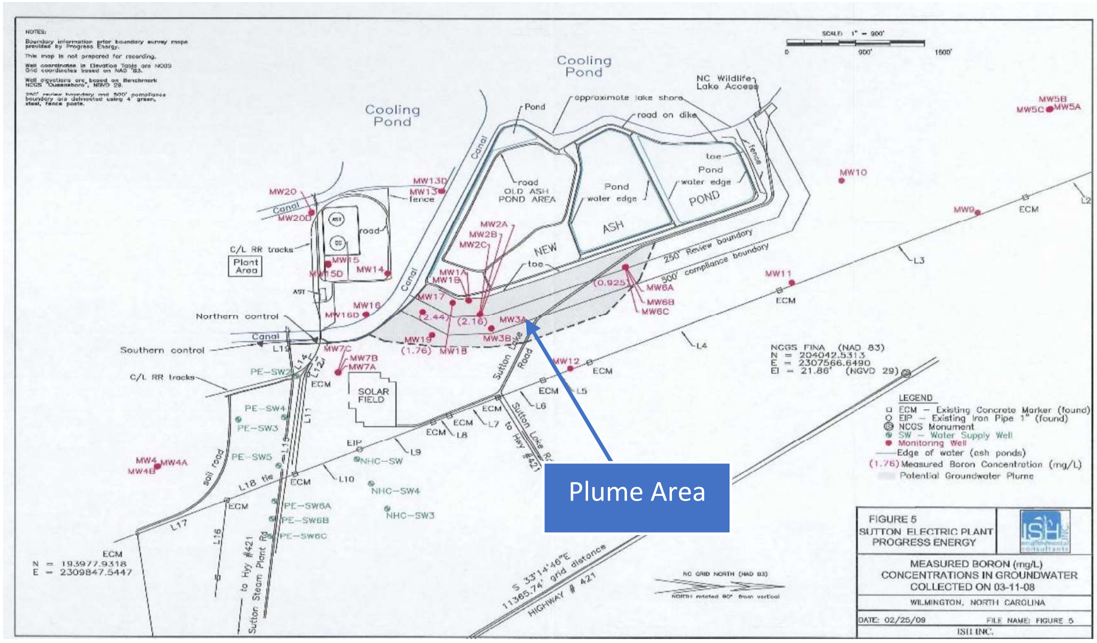
In 1992, DEQ performed a Preliminary Assessment/Site Inspection on behalf of EPA at the facility (Hart Exhibit 59). Sampling was performed which indicated that groundwater had been impacted by the following metals above 2L Standards or IMACs: arsenic, barium, beryllium, chromium, iron, lead, nickel, selenium and thallium. The report recommended a medium priority for further assessment and also recommended that the nearby wetlands and municipal well be investigated to determine if they had been impacted by contaminants.

In 1999, DEQ performed an Expanded Site Inspection on behalf of EPA (Hart Exhibit 60). The report indicates that multiple wells, including a community well, had been impacted by site contaminants, and that monitoring wells on the property had also been impacted. The report recommended that the site be considered for further action under Superfund.

In 2003, DEP entered into an Administrative Agreement with DEQ to conduct voluntary assessment and remediation at the FADA. In 2004, a Phase I Remedial Investigation Work Plan was submitted to evaluate the FADA and included groundwater, soil, surface water, and sediment sampling (Hart Exhibit 61). The 2004 Phase I Remedial Investigation Report indicated that groundwater in the FADA was impacted with arsenic above the 2L Standard (Hart Exhibit 62). In 2005, a Phase II Remedial Investigation was completed to further delineate the ash buried in the FADA, and the groundwater impacts from the arsenic concentrations in groundwater were only found where the well was screened within the coal ash (Hart Exhibit 63).

In 2006, DEP submitted a "containment remedy" for natural attenuation of groundwater impacts and land use controls for impacted soil (Hart Exhibit 64). However, DEQ did not concur with DEP's Remedial Action Plan (RAP) and indicated that active groundwater remediation may be necessary and additional sampling was needed to evaluate the RAP (Hart Exhibit 65). Rather than performing these actions, DEP instead chose to voluntarily terminate the voluntary agreement with DEQ in 2008 (Hart Exhibit 65).

In 2009, a groundwater assessment work plan was prepared for the site to asses both the FADA and the ash basins (Hart Exhibit 66). The report includes an evaluation of historical groundwater data and concludes that groundwater has been impacted by arsenic, total dissolved solids, boron, and pH from the ash ponds at the site and proposes that additional monitor wells be installed at the site to define the extent of impacts. A groundwater "plume" figure from the report identifying an area of groundwater impact from boron outside the compliance boundary is provided below (note that the concentrations in the figure are in units of mg/L and not µg/L as is used elsewhere in this testimony; concentrations in µg/L can be obtained by multiplying the concentrations in mg/L by 1000).



A graph of arsenic concentrations versus time for downgradient well MW-2C from the same report is provided below and indicates increasing concentrations (note that the 2L Standard for arsenic prior to 2000 was 50 µg/L (0.05 mg/L) and after January 1, 2000, was 10 µg/L (0.01 mg/L):

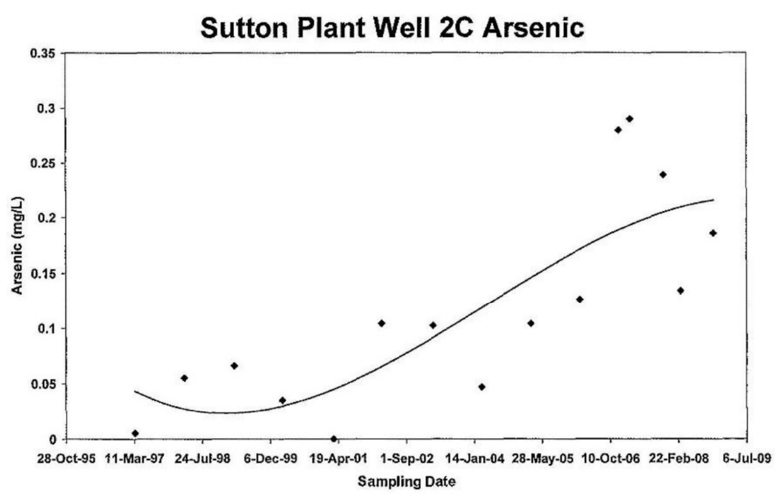


Figure 8: Time Series Scatter Plot for Arsenic Concentrations in Groundwater at Well MW-2C

It appears that sometime after this submittal, DEQ indicated that the FADA and the ash basin groundwater issues could be managed together under the Division of Water Resources (Hart Exhibit 67).

In 2015, DEQ assessed DEP a fine for over $25 million for violations of its NPDES permit and the 2L Standards beyond the compliance boundary at the Sutton facility for arsenic, boron, iron, manganese, selenium, thallium, and TDS (Hart Exhibit 68). DEQ's issuance of a civil penalty assessment confirms that groundwater impacts beyond a compliance boundary are subject to enforcement and corrective action in accordance with NCAC Title 15A 2L .0106.

Q. PLEASE DISCUSS WHEN DEP BECAME AWARE OF GROUNDWATER CONTAMINATION ASSOCIATED WITH THE COAL ASH BASINS AT THE FACILITY? PLEASE BRIEFLY DESCRIBE RESULTS OF GROUNDWATER ASSESSMENT AND MONITORING OVER TIME AT THE FACILITY (METALS OF CONCERN, GROUNDWATER FLOW, CONCENTRATION TRENDS OVER TIME, ETC.).

A. A brief summary of groundwater contamination is provided in bullet format below, which is then described in greater detail in the paragraphs that follow.

<u>Summary</u>

- Groundwater monitoring began in the mid-1980s and indicated groundwater impacts of TDS and chlorides inside and outside the compliance boundary.

- By 1990, concentrations of iron were detected well above the 2L Standard outside of the compliance boundary and at monitoring wells along the property boundary. Background well MW-5C was sampled as early as 1990.
- Additional wells were installed around the FADA in the early 1990s that had been sampled one time until being used in voluntary monitoring again in 2006. Concentrations of arsenic, boron, iron, and manganese were detected above 2L Standards.
- Boron was included as an analyte in 2006 when voluntary groundwater monitoring activities began at the facility and concentrations were detected exceeding the 2L Standard. However, DEP did not include boron as an analyte for wells outside of the compliance boundary until 2011.
- In 2011, groundwater monitoring was conducted at the compliance boundary as requested by DEQ. Iron (up to 3,560 μg/L compared to 2L Standard of 300 μg/L and later established BTV of 1,494 μg/L), manganese (up to 2,770 μg/L compared to the 2L Standard of 50 μg/L and later established BTV value of 746 μg/L), thallium (up to 0.631 μg/L compared to the IMAC of 0.2 μg/L), total dissolved solids (up to 610 μg/L compared to the 2L Standard of 500 μg/L and BTV of 210 μg/L), and boron (up to 3,600 μg/L compared to the 2L Standard of 700 μg/L and BTV of 50 μg/L) were detected above the 2L Standards and background values at or outside the boundary.

- In 2015, cobalt and vanadium were included as analytes and indicated IMAC and background value exceedances in compliance monitoring wells.
- Despite the presence of groundwater impacts outside the compliance boundary as early as 1990 and evidence of potential off-site water supply well impacts, DEP did not perform activities to mitigate the groundwater impacts until the facility was designated high risk under CAMA and closure of the ash basins was required, even though the facility was retired in 2013.

Site maps showing the well locations and groundwater flow are included as Hart Exhibit 49A and an Excel spreadsheet of groundwater data for the facility is included as Hart Exhibit 49B.

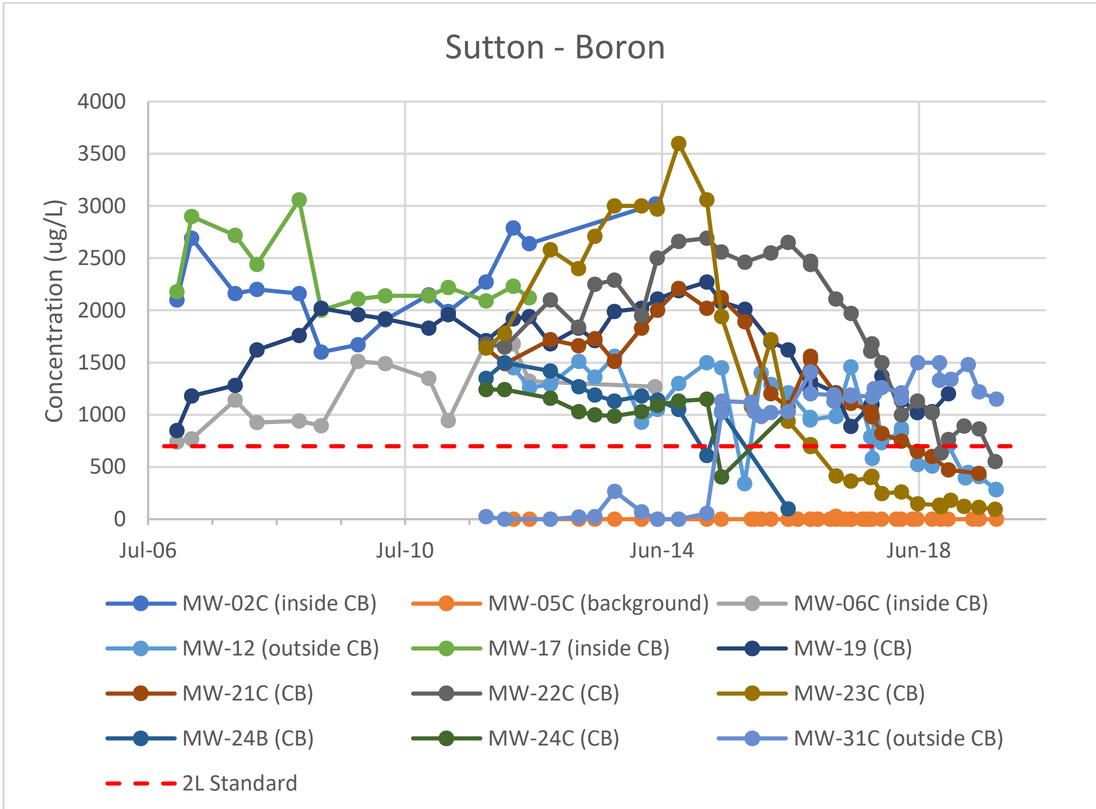
Details

Monitoring at Sutton began in the mid-1980s. By 1990, monitor wells MW-2C, MW-4B, MW-5C, MW-6C, MW-07C, MW-8, MW-9, MW-10, MW-11, and MW-12 had been installed and sampled. MW-2C and MW-6C are located downgradient of the ash basin area and within the compliance boundary (CB). MW-2C (inside CB) indicated concentrations of iron exceeding the 2L Standard from 1991 through 2014. Arsenic was detected above the 2L Standard beginning in 1998 in MW-2C and boron and manganese were detected above the 2L Standards from 2006 (the first year the compounds were included as analytes) through 2014 in both wells. MW-4B (background) is located to the southeast of the ash basins, downgradient of the basins, however DEP identified the well as a background well in the 2014 Groundwater Assessment Plan. Iron was detected above the 2L Standard from 1990 through 2016 in MW-4B and manganese concentrations appeared to be increasing and exceeded 2L Standards from 2014 through 2016. MW-5C (background) is located north and upgradient of the ash basins, adjacent to the northern portion of the cooling pond and is identified as a background well. With the exception of low levels of manganese detected above the 2L Standard from 2012 through 2016, no exceedances were detected in the background well.

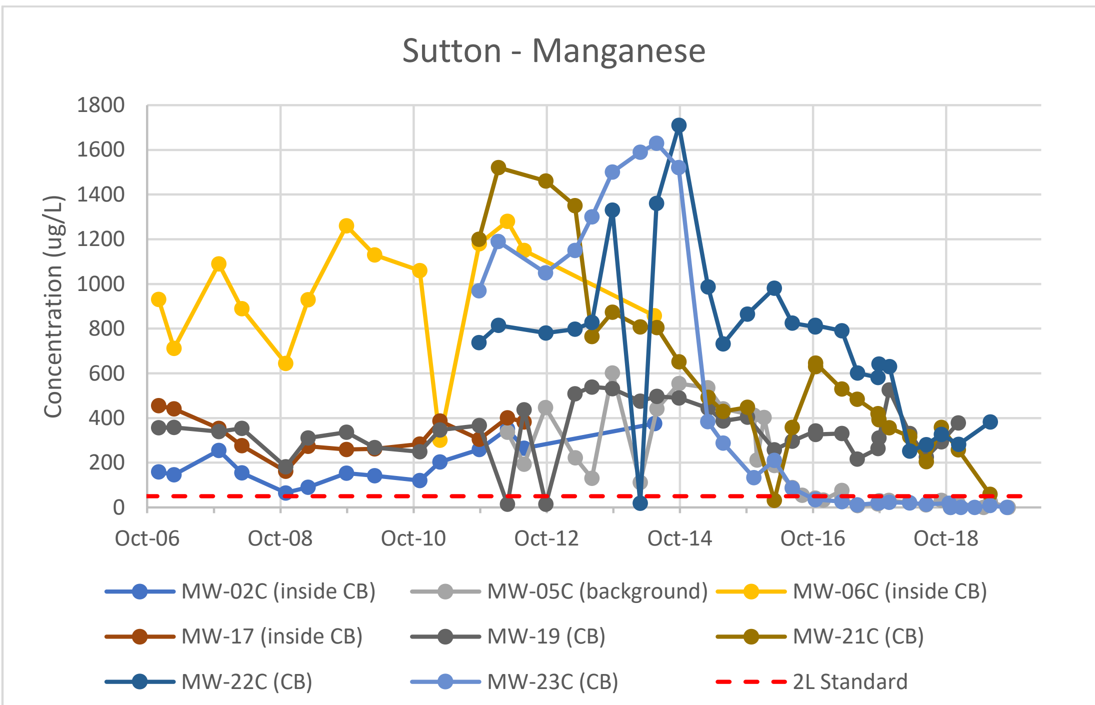
MW-7C is located downgradient of the ash basins and well outside of the compliance boundary. With the exception of isolated concentrations of compounds exceeding the 2L Standards and IMAC, manganese and vanadium are the only two compounds consistently detected at concentrations exceeding the applicable 2L Standards. In MW-7C (outside CB), manganese was detected above the 2L Standard but comparable to background concentrations from 2012 through 2019 and vanadium was detected above the IMAC from 2015 through 2019.

MW-12 is located along the eastern property boundary, well outside of the compliance boundary, and indicated elevated concentrations of iron above 2L Standards, from 1990 through 2019 (several sampling events in 2008 and 2010 and 2013 and 2015 did not indicate exceedances). Boron and manganese were included in the sample list from 2012 through 2017 and were detected at concentrations exceeding the 2L Standards during that time period. MW-12R (outside CB) was installed in 2017 to replace MW-12 and concentrations of iron and manganese remained similar to the MW-12 samples.

A graph depicting concentrations of boron in downgradient wells compared to the 2L Standard and background well is included below.



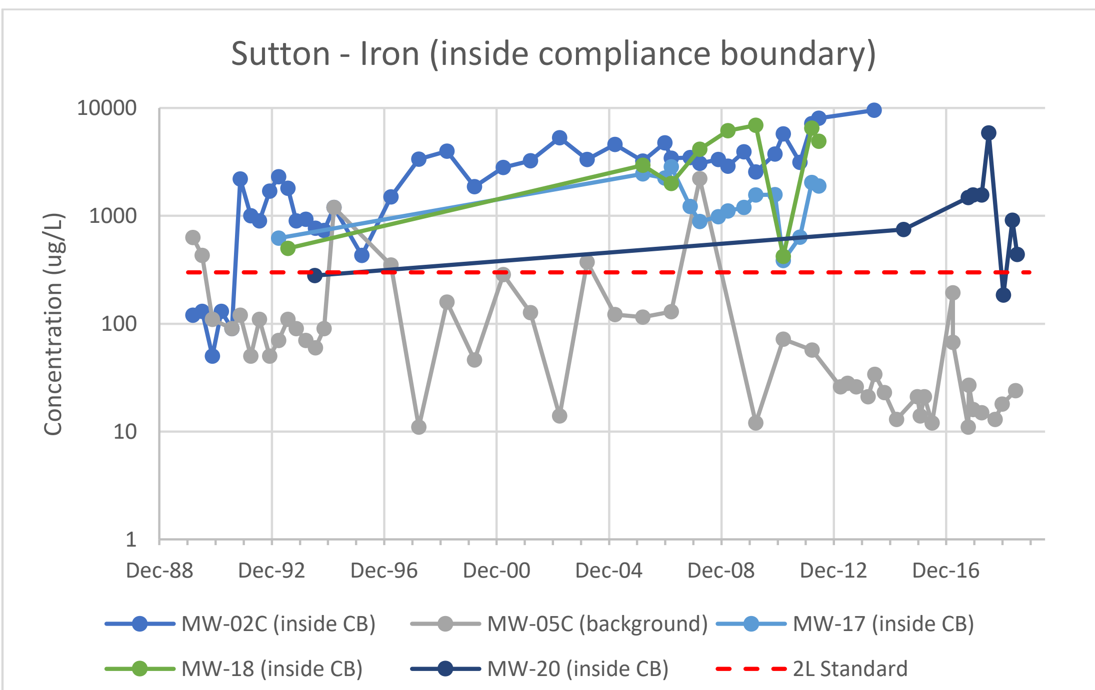
MW-13 through MW-16 and MW-20 are located along the waste boundary of the former ash disposal area and within the compliance boundary. Iron was detected above the 2L Standards in MW-15 (inside CB) between 1992 and 2015 and in MW-16 (inside CB) from 2015 through 2019. MW-20 (inside CB) was analyzed for iron in 1994 and was not sampled again until 2015 at which time iron and manganese were detected above the 2L Standards through 2019. Total dissolved solids, cobalt, and vanadium were detected above the applicable standards from 2017 through 2019 and thallium and sulfate appeared to be increasing to concentrations exceeding the applicable standards. MW-17 and MW-18 were installed southeast of the ash basins and within the compliance boundary. The wells were sampled once in 1993 and then from 2006 through 2012 at which time the wells were abandoned. Iron was detected well above the 2L Standard and background concentrations in both wells from the original sampling event in 1993 and from 2006 through 2012. Boron and manganese were also detected above the 2L Standards in MW-17 (inside CB) from 2006 through 2012 and arsenic was detected in both wells above the 2L Standards during that time period. A graph depicting manganese concentrations compared to the background well and 2L Standards is shown below.

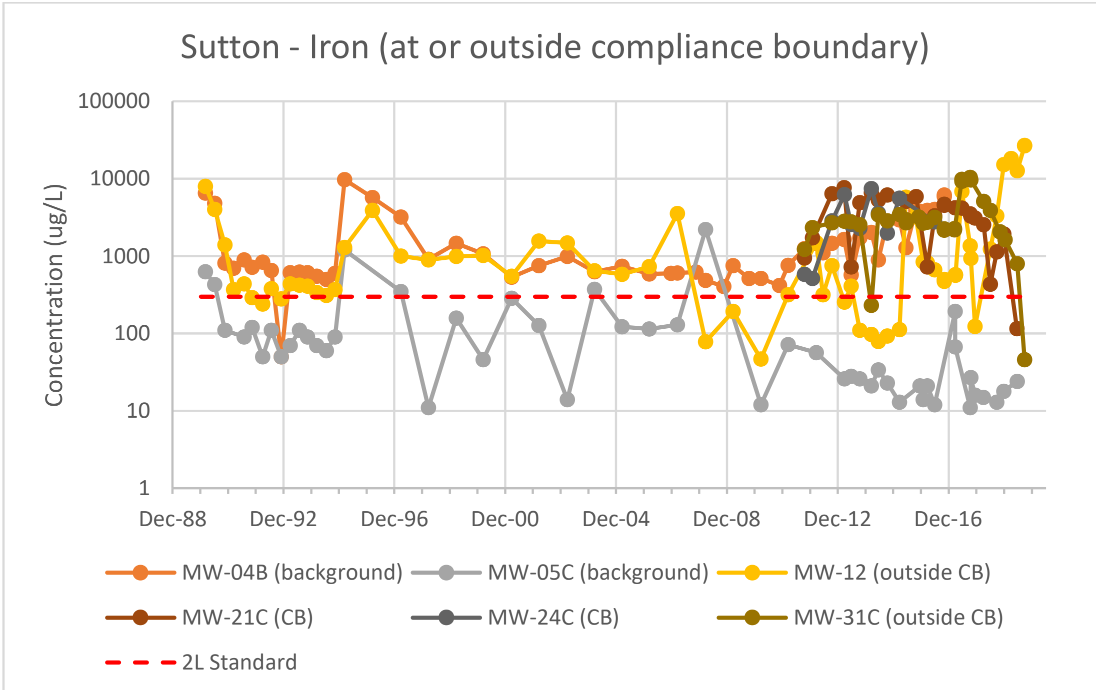


MW-19 is located outside of the compliance boundary and downgradient of the ash basin. The well was analyzed for iron in 1993 and for a longer list of analytes from 2006 through 2018. Boron and manganese were detected above the 2L Standards from 2006 through 2018. Thallium was detected at concentrations exceeding the IMAC from 2010 through 2018, and cobalt and vanadium were detected above the IMAC when the compounds were included as an analyte from 2015 through 2018.

In 2011, DEP began compliance monitoring to meet the requirements of the NPDES permit. Monitoring wells MW-21C through MW-24C and MW-27B are located along the compliance boundary, downgradient of the basins. MW-28B/C are located to the southeast of the basins, outside of the compliance boundary, and MW-31C is located to the east of the basins at the property boundary and well outside of the compliance boundary. Iron and manganese were detected above the 2L Standards and above background concentrations from 2011 through 2018 (2019 for manganese), boron was detected above the 2L Standard from 2011 to 2018, and arsenic was detected above the 2L Standard from 2013 through 2018. Cobalt and vanadium were included in the analyte list from 2015 through 2019 and concentrations in MW-21C (CB) exceeded the IMAC during that time period. Boron and manganese from 2011 through 2019, and cobalt from 2015 through 2019 exceeded the applicable standards in MW-22C (CB). Thallium was also detected at concentrations exceeding the IMAC from 2012 through 2019. MW-23C (CB) indicated early 2L Standard exceedances of boron and manganese (2011 through 2016), with concentrations decreasing below the standard in the following years. Cobalt and vanadium were consistently detected above the IMAC from 2015 through 2019. MW-24B (CB) and MW-24C (CB) indicated concentrations of boron and manganese above 2L Standards from 2011 through 2016 and total dissolved solids and iron were also detected above the 2L Standards in MW-24C during that time period (total dissolved solids dropped below the 2L Standard concentration in 2014).

MW-27B (CB) is located north of the ash basins and, according to DEP maps, downgradient to cross-gradient of the ash basins. Manganese and selenium were detected above the 2L Standards from 2011 to 2015, and decreased below the standards in the following years. MW-31C (and replacement well MW-31CR) is located on the eastern property boundary outside of the compliance boundary. From 2011 through 2018 boron, iron, and manganese were detected well above the 2L Standards and background concentrations. From 2016 through 2019, cobalt significantly exceeded the IMAC. Graphs depicting iron concentrations in and outside of the compliance boundary are included below.





In 2017, background threshold values (BTVs) for the site were established using background wells MW-4B and MW-5C. The BTVs for boron, total dissolved solids, cobalt, iron, manganese, and vanadium were above the 2L or IMAC Standards for at least one aquifer unit. However, concentrations detected in site wells exceeded the BTVs in at least one sample. The boron plume at the site appears to be within the surficial upper and lower flow units and the BTVs for those aquifers do not exceed the 2L Standard. The BTVs for selenium and thallium did not exceed the 2L Standards and IMAC. For any 2L exceedances where the BTVs do not exceed the 2L Standard, a violation of the 2L Standard exists.

XI. WEATHERSPOON STEAM STATION

Q. PLEASE PROVIDE A HISTORY OF COAL ASH BASINS AT THE PLANT.

A. The Weatherspoon station began generating electricity in 1949. In 1955, the original ash basin was constructed to contain sluiced CCR and was expanded twice, once in 1963 and once in 1979. A dry stack disposal area was constructed within the ash basin footprint in 2002. In 2007, a vertical expansion was constructed within the basin. The plant stopped sluicing into the ash basin in October 2011 upon the shutdown of the coal-fired electricity generation operations at the plant. Approximately 2 million cubic yards of CCRs were placed within the ash basin.

In addition to sluiced CCRs, additional wastewater streams disposed in the ash basin include condenser and heat exchanger cleaning wastes, water and sludge from chemical metal cleaning wastes, turbine sump and basin sludge, air preheater wash, spent sandblast material, and low volume wastes.

Q. PLEASE DISCUSS WHEN DEP BECAME AWARE OF GROUNDWATER CONTAMINATION ASSOCIATED WITH THE COAL ASH BASINS AT THE FACILITY AND BRIEFLY DESCRIBE RESULTS OF GROUNDWATER ASSESSMENT AND MONITORING OVER TIME AT THE FACILITY.

A. A brief summary of groundwater contamination is provided in bullet format below, which is then described in greater detail in the paragraphs that follow.

<u>Summary</u>

- Sampling began at the Weatherspoon plant within the compliance boundary in 1990. MW-1 was located upgradient of the basin, but along the waste boundary, and wells MW-2 through MW-5 were located downgradient of the ash basin. Concentrations of iron were elevated in the downgradient wells in the 1990s, particularly in well MW-5. Although MW-1 was located within the compliance boundary and ultimately not a good background well, in early monitoring in the 1990s, it may have been reasonable to conclude that groundwater concentrations in downgradient wells were not significantly elevated above levels in MW-1. In 2006, when groundwater monitoring resumed, boron and manganese were detected at concentrations exceeding the 2L Standards in MW-4.

- In 2010, compliance wells CW-1 through CW-3 were installed along the compliance boundary cross-gradient and downgradient of the ash basin. Background well BW-1 was installed along the upgradient compliance boundary to establish naturally occurring concentrations. Concentrations in the compliance boundary wells were generally consistent with background.
- Additional wells were installed in and around the ash basin in 2011 and 2012 within the compliance boundary. Concentrations of boron, sulfate, total dissolved solids, iron, manganese, and cobalt were detected above the 2L Standards, IMAC, and background values.

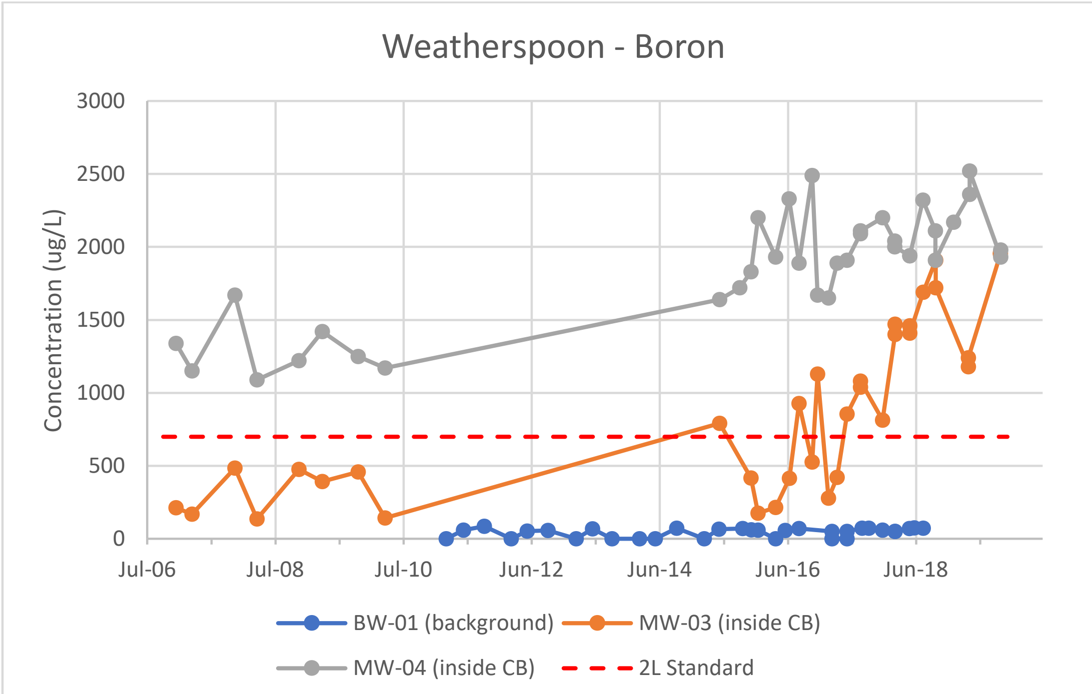
Site maps showing the well locations and groundwater flow are included as Hart Exhibit 50A and an Excel spreadsheet of groundwater data for the facility is included as Hart Exhibit 50B.

<u>Details</u>

Groundwater monitoring began at the Weatherspoon facility as early as 1990. Monitoring wells MW-1 through MW-5 were installed within the compliance boundary and initially sampled in 1990. MW-1 was installed to the north of the ash basin, within the compliance boundary but generally upgradient of the ash basin. MW-2 through MW-5 were installed on the south side of the ash basin in the downgradient direction. Iron was detected at concentrations well above the 2L Standard in monitoring wells MW-1 (inside CB), MW-2 (inside CB), MW-3 (inside CB), and MW-5 (inside CB) from 1990 through 2011, and again when the wells were sampled in 2015, with the exception of MW-1. Although MW-1 was located within the compliance boundary and ultimately not a good background well, in early monitoring in the 1990s, it may have been reasonable to conclude that groundwater concentrations in downgradient wells were not significantly elevated above levels in MW-1. Results from 2015 to 2019 in monitoring well MW-1 indicated concentrations of iron were below the 2L Standard.

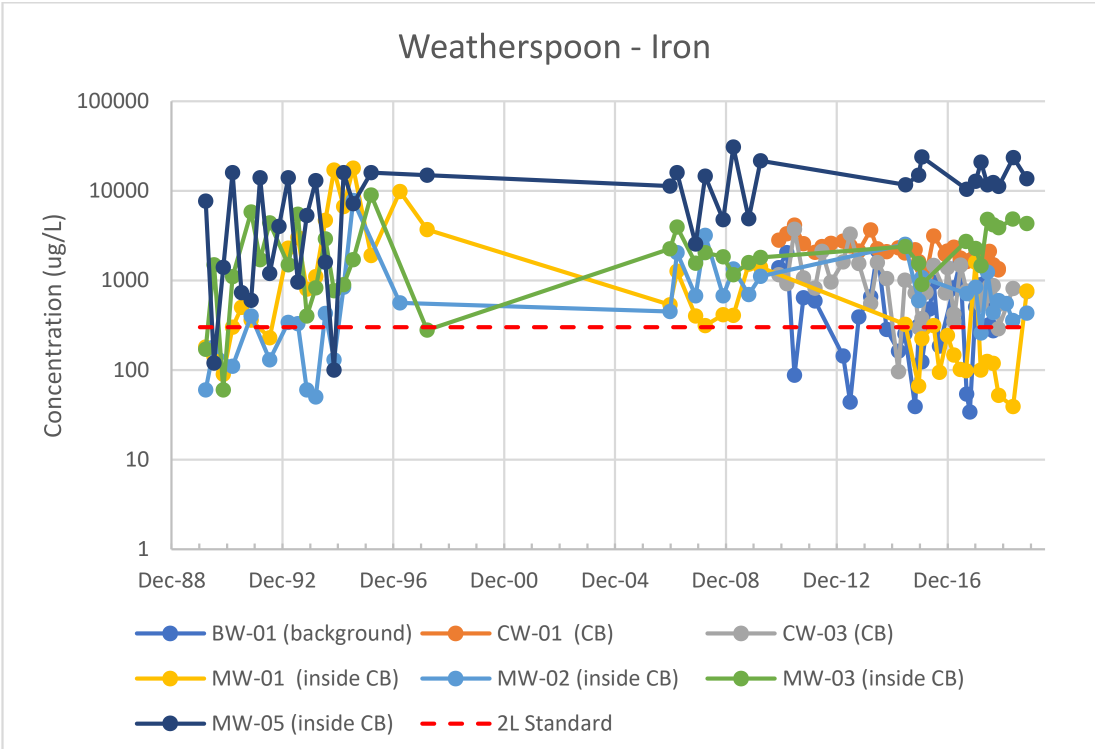
Boron was included in the analyte list beginning in 2006, at which time concentrations in monitoring well MW-4 (inside CB) were well above the 2L Standard and showing an increasing trend. Thallium was also detected in MW-4 above the IMAC from 2015 through 2019. MW-3 (inside CB) indicated increasing concentrations of boron over time that increased above 2L Standards from 2017 through 2019. In MW-3, arsenic concentrations also increased and concentrations were consistently above the 2L Standard beginning in 2018. Prior to the installation of BW-1 (background) in 2010 as discussed below, no background well was established for the Site for comparison to naturally occurring concentrations. The graph below shows the boron concentrations in

MW-3 (inside CB) and MW-4 (inside CB) compared to the background concentrations in BW-1 (after it was installed in 2010).



As indicated above, concentrations of boron in these two wells have been increasing with time.

In 2010, monitoring wells CW-1 and CW-2 were installed along the downgradient compliance boundary, CW-3 was installed along the cross-gradient side of the compliance boundary to the northeast, and background well BW-1 was installed upgradient of the ash basin along the northern side of the compliance boundary. Iron was detected in the three down to cross gradient compliance wells and in the background well at concentrations above the 2L Standard. In comparison to the upgradient background well, the concentrations of iron detected in CW-1 (CB) and CW-3 (CB) were higher than the concentrations in BW-1 (background). The graph below shows concentrations of iron from the original voluntary monitoring wells (MW-1, MW-2, MW-3, and MW-5) and the compliance wells CW-1 and CW-3 compared to background concentrations. Please note the vertical scale is logarithmic because of the high concentrations in some wells.



Nested monitoring wells MW-8S/I/D, MW-44S/SA/I/D, and MW49I/D were installed within the ash basin waste boundary and were initially sampled in 2012. Boron, total dissolved solids, iron, and manganese were detected above the 2L Standards in each sampling event from MW-8I (inside CB) and MW-8S (inside CB), and iron was detected above the 2L Standard in MW-8D (inside CB) in at least one sampling event between 2012 and 2016. Boron, total dissolved solids, sulfate, cobalt, iron, and manganese were detected in the shallow well above the 2L Standards and IMAC between 2012 and 2017.

Boron, total dissolved solids, iron, and manganese were detected in the intermediate well MW-49 (inside CB) above 2L Standards between 2012 and 2017. Nested wells MW-33S/I/D and MW-41I/D were installed cross-gradient of the ash basin within the compliance boundary, to the southwest and the northeast of the basin, respectively. Iron, manganese, and total dissolved solids were detected above the 2L Standards from 2012 through 2019 in the intermediate and deep wells at MW-33 (inside CB), and iron and manganese were detected above the 2L Standard in the shallow well. Cobalt and vanadium were also detected above the IMAC from 2015 through 2019 in the shallow MW-33 well. Iron was detected above the 2L Standard in both the intermediate and deep well at MW-41 (inside CB) between 2012 and 2019.

Monitoring wells MW-6, MW-7, MW-52, MW-53I/D, MW-54D, and MW-55D/I were installed downgradient of the ash basin, within the compliance boundary, and were sampled once in 2012 and then again from 2017 through 2019. Iron was detected at concentrations above the 2L Standard in MW-6 (inside CB), MW-7 (inside CB), MW-52 (inside CB), MW-53D/I (near CB), and MW-55D (inside CB) during each sample event. Cobalt was detected in MW-52 and MW-55I from 2017 through 2019 above the IMAC Standard. Manganese and boron were also detected above the 2L Standards in MW-55I from 2012 to 2019.

XIII. RESPONSE ACTIONS

Q. BASED UPON YOUR ANALYSIS, BEFORE THE DAN RIVER SPILL HAPPENED, DID DEP UNDERTAKE REASONABLE AND PRUDENT

ACTIONS AND PRACTICES IN A TIMELY MANNER TO RESPOND TO GROUNDWATER CONTAMINATION AT ITS ASH BASINS AND ADDRESS CLOSURE OF ITS COAL ASH BASINS?

A. No. A summary of the facts and my conclusions regarding this question is provided below.

1. The knowledge base concerning the impact to groundwater from unlined coal ash basins increased over time from the 1980s to the mid-2000s.
2. The utility industry, including DEP, knew about the reasonable potential for contamination of groundwater from coal ash basins as early as the 1980s.
3. By the late 1980s, as a result of groundwater contamination concerns at the Sutton facility, DEP was aware that 1) DEQ had significant concerns about the presence of groundwater contamination from coal ash basins, 2) a clay bottom liner installed in a new ash basin by DEP was a potential method to minimize the potential for groundwater impacts, 3) if concentrations of compounds in groundwater were elevated from a coal ash pond but did not exceed the groundwater standards, they were still of concern to DEQ and needed to be evaluated further, and 4) groundwater impacts at and beyond the compliance boundary from coal ash basins did occur.
4. At the DEP Robinson, Roxboro, and Weatherspoon facilities, groundwater monitoring had been conducted as early as the early to

mid-1990s and indicated groundwater contamination issues with coal ash disposal areas.

5. By the early 1990s DEP knew that, by modifying coal ash facilities, it could decrease metals concentrations in water and protect the environment. Discharge of selenium from the coal ash basins at the Roxboro facility affected fish reproduction causing a decline in fish populations in Hyco Lake in the 1970s and 1980s, and resulting in estimated damages of $877 million. North Carolina issued a fish consumption advisory for Hyco Lake in 1988. In approximately 1990, DEP installed a dry ash handling system to meet new permit limits for selenium, which improved water quality and resulted in a complete rescission of the fish advisory in 2001. Nonetheless, when groundwater impacts were identified in the area of the coal ash basins, similar responsive remedial actions could have been taken but were not.
6. By the early 2000s, as a result of an EPA Regulatory Determination, it was clear to the electric utility industry that EPA's documentation of damage cases from coal ash basins and their assessments of environmental impact would lead to increased scrutiny, environmental sampling, and potential closure of ash basins.
7. In 2006 through 2008, DEP implemented voluntary groundwater monitoring at its ash basins as part of the Utility Solid Waste Activities Group (USWAG) effort to address EPA's concern about groundwater impacts from coal ash basins. The USWAG action plan was the electric

utility industry's commitment to adopt groundwater performance standards at facilities that manage CCRs and to implement a comprehensive monitoring program to measure conformance with the groundwater standards at facilities that managed CCRs. The utility industry offered the USWAG action plan as an alternative to mandatory federal requirements because the utility industry committed to work within existing state regulatory programs to address groundwater impacts and to protect human health and the environment. Yet, even after the groundwater data were collected which irrefutably indicated groundwater impacts associated with the coal ash basins, DEP did not follow the USWAG action plan about how to respond to groundwater data collection where groundwater impacts were detected. The USWAG action plan indicates that, on detecting groundwater impacts, DEP should have worked with the regulatory agency to further assess conditions and, as needed, develop corrective action programs. Instead, DEP submitted the data to DEQ without evaluation or responsive action.

8. In 2010, EPA proposed rules to regulate CCRs at electric generating plants. In the proposed rule, EPA included two options for public consideration to manage CCRs in landfills and impoundments: one in which CCRs would be managed as a hazardous waste under RCRA subtitle C and the other in which CCRs would be managed as non-hazardous waste under RCRA subtitle D.

9. In 2015, EPA issued its final CCR rule which indicated that CCRs disposed in landfills and ash basins would continue to be managed as non-hazardous wastes, and the rules also established national minimum criteria for existing and new CCR surface impoundments including location restrictions, design and operating criteria, groundwater monitoring and corrective action, and closure requirements and post closure care.

10. Before the EPA's final rule was issued, however, between 30,000 to 39,000 tons of coal ash and 27 million gallons of coal ash basin water were released into the Dan River from the Duke Energy Carolinas (DEC) Dan River facility in February 2014, and as a result, North Carolina issued its own Coal Ash Management Act (CAMA). CAMA included a procedure for prioritization of coal ash basin closures, requirements to convert facilities to dry ash handling by certain dates (to eliminate the need for sluicing to ponds), accelerated timeframes for performing receptor surveys, and accelerated timeframes for groundwater assessment plans and corrective action plans.

11. Although there was some uncertainty about how coal ash ponds would be managed prior to the enactment of CAMA and the promulgation of federal CCR rules, there was no ambiguity about the requirements of North Carolina's groundwater corrective action rules. (Title 15A NCAC Subchapter 2L, as referred to herein as the 2L Rules). When groundwater contamination is detected in association with a permitted

ash pond – i.e., .if a 2L Standard for a compound is exceeded -- the 2L Rules require that the responsible party determine the nature and extent of the contamination, terminate and control the discharge, mitigate hazards, perform receptor surveys to identify potential receptors of the contamination, and propose and implement corrective actions.

12. This lack of ambiguity about requirements of the 2L Rules is confirmed by DEP's statements to its insurance carriers in 2011 which advised that, regardless of when EPA may act or what other states may do, 1) North Carolina is taking aggressive action on coal ash facilities, 2) there are existing regulations (i.e., the North Carolina 2L Rules for groundwater) that describe the corrective action process if there are exceedances at the compliance boundaries, and 3) North Carolina regulations already provide for the same potential closure scheme as EPA's proposed rules.

13. The detections above 2L Standards within or beyond the compliance boundary or in the bedrock aquifer at North Carolina DEP facilities should have triggered additional actions such as installation of wells at the compliance boundary, installation of additional monitoring wells to define the extent of impacts, and implementation of corrective actions, as warranted. However, rather than responding proactively to groundwater contamination at its coal ash basins, DEP chose to wait until regulatory agencies noted groundwater contamination concerns from DEP's data submittals. Similarly, in South Carolina, detections above the maximum contaminant levels (MCLs) at the South Carolina

DEP facility should have triggered additional assessment and, if warranted, corrective action.

14. Even after wells were installed along compliance boundaries at DEQ's direction in 2010 at all of the DEP North Carolina facilities, DEP continued to indicate as late as 2013 that it strongly believed that the iron and manganese exceedances were the result of background concentrations and that these compounds only had secondary MCLs. However, there are several flaws with DEP's conclusions. First, secondary MCLs are not the standard for groundwater in North Carolina and are no defense to an exceedance to the 2L Standard. Second, in almost all cases the exceedances were, in fact, significant. Third, in almost all cases, actual data from the facilities were irrefutable that the groundwater impacts above 2L Standards were not solely from background conditions.

15. In addition to sluicing coal ash, over time DEP discharged other wastewater streams to the basins, and it did so in some cases without evidence of how those additional waste streams, such as advanced air pollution control technology wastewaters and sandblast material, would impact the basins and groundwater. In fact, there is evidence that the addition of FGD wastewaters led to increased groundwater contamination from the basins and that DEP was aware of these issues. However, DEP did not address the increased contamination to minimize

the impact to groundwater or bring the condition to the attention of DEQ.

16. At the DEP Asheville, Cape Fear, HF Lee, Roxboro, and Sutton facilities, one or more coal ash basins were taken out of service or only used for very limited purposes starting in the 1960s through the 1980s because they were functionally full; however, there were no efforts to close the ponds. In fact, many of the basins continued to receive stormwater discharge even after they were functionally full which maintained the hydraulic head on the basins, thus continuing to contribute to groundwater impacts.

17. In 2013 and 2014, Duke Energy documents acknowledged that DEP did not yet have any approved closure plans and that it had failed to make “reasonable efforts” toward the closure of unclosed basins.

18. Other industries in North Carolina with similar types of permitted disposal facilities were actively addressing groundwater impacts with DEQ and implementing corrective action to address the sources of groundwater contamination in the 1970s to 1990s.

19. It was not until after the Dan River release in February 2014, and the resulting pressure to address concerns from the public and regulators, that DEP committed to implement full assessments, closure evaluations, some dry ash handling conversions, and closure activities on an expedited basis.

20. It is evident from my analysis that, as a result of groundwater monitoring

data at its coal ash basins and increased internal concern with groundwater contamination from coal ash basins, DEP should have taken responsive action sooner and initiated a systematic plan to address its coal ash basins by closing long out of use basins and, for basins still receiving CCRs, converting facilities to dry ash handling, eliminating other wastewater streams, engaging in closure planning, and evaluating methods to reduce environmental impact while the basins were still operational.

Q. HOW WOULD COSTS THAT DEP IS SEEKING FOR COAL ASH RELATED ACTIVITIES LIKELY BE DIFFERENT TODAY IF DEP HAD INITIATED ACTIONS SOONER TO ADDRESS ITS ASH BASIN PRACTICES?

A. DEP’s delay in addressing groundwater contamination issues at its facilities and delay in closure of ash ponds that were no longer in use or only used for limited purposes (e.g., a basin that was no longer receiving CCRs but which received stormwater or was occasionally used for ash stacking), increased the cost today as follows:

- DEP's actions and failure to take actions before the Dan River spill prompted the adoption of environmental requirements that imposed accelerated schedules to address coal ash basin problems, particularly at the Asheville and Sutton facilities, and costs for accelerated actions are almost always greater than costs under non-accelerated timeframes.

- Further, DEP's admission that it was criminally negligent in how it managed some sites likely prompted a lack of confidence by regulators and the public that less costly actions would be effective, and prompted requirements that DEP take more extensive and high-cost approaches, such as the high-cost beneficiation requirement.
- Most of the expenditures that DEP seeks to recover for coal ash basin closures and CCR disposal were incurred at coal plants that are retired and have not been used for several years to produce power for ratepayers. In fact, the only DEP coal fired facilities that were still in operation at the time of the Dan River spill in 2014 were the Asheville, Mayo, and Roxboro facilities.
- Furthermore, substantial parts of the expenditures were incurred to close ash basins that have not been in substantial use for decades.
- By engaging in reasonable monitoring and taking adequate responsive actions, some of the costs would have been included in the cost of service for customers while the coal plants and ash ponds were in use.
- DEP's costs are higher today due to inflation.
- The requirement that Duke connect all households to alternate water supplies was likely a result of DEP's delay in addressing groundwater impacts. Prior to the Dan River release, DEP maintained that drinking water wells were not affected, but it is unheard of for a company to have to connect properties to alternate water when those water supplies are not impacted. In my opinion, this requirement that DEP provide permanent water supplies

was warranted by law because DEP, once it knew it had groundwater issues, had failed to determine the extent of groundwater impacts, reliably establish background concentrations, and perform adequate receptor evaluations. Instead, DEP contended that there were few if any water supply well receptors in the area of its facilities and maintained that position despite there being no indication that it performed comprehensive receptor surveys until required to do so under CAMA. Thus, it appears that these costs were directly related to DEP's delay in evaluating groundwater impacts. Therefore, the $3,481,096 requested by DEP related to connection to alternate water supplies should not be included in the recoverable costs.

Q. PLEASE DESCRIBE YOUR ANALYSIS.

A. It is difficult at this point in time to estimate what costs would have been incurred 10 or more years ago if DEP had responded more promptly to the evidence of groundwater impacts. For example, conversion to dry ash handling would have required investment in retrofitting the plant and may have increased costs to transport ash to an off-site or on-site landfill. Therefore, I cannot provide line-by-line estimates of earlier costs.

However, I can reasonably make a simplified estimate of the reduction in costs using a three-step approach, which I have referred to here as Step "A," Step "B," and Step "C." Step A reduces the system costs to exclude the expenditures on permanent water supply. Step B reduces the system costs to exclude the expenditures for closure of ponds that have been functionally full or were only in limited use for non-CCR disposal purposes after the 1980s. Step

C calculates the amount that would be excluded from the remaining system costs after Steps A and B to reflect the time value of money if closure or other responsive actions had been taken in a reasonable time frame.

Step A

In Step A, I reduced the system costs by the costs for permanent water supply as follows:

- Ms. Bednarcik identified $415,937,510 in system expenditures that were deferred for CCR closure activities between 9/1/17 to 6/30/19. (See Bednarcik pre-filed Direct Testimony, Tables 1-6). Please note that these costs do not include the investment at active plants to convert to dry ash handling or to address wastewater streams that were formerly discharged to ash basins.
- In Step A, I removed the permanent water supply connection costs of $3,481,096 as discussed above. This step results in non-excluded remaining costs of 412,456,414.

Step B

In Step B, I evaluated each facility individually and I excluded costs for basins that should have been taken out of service long ago at the Asheville, Cape Fear, HF Lee, Roxboro, and Sutton facilities. It is reasonable to conclude that today's ratepayers should not have to pay for closure of coal ash basins that were out-of-use and functionally full prior to 1990. For facilities that have closure planning costs associated with both these older basins and more recently used basins (Cape Fear, HF Lee, and Roxboro), I calculated the ratio of ash placed in the older basin(s) to the total ash to be removed to determine the excluded costs. For the Sutton facility in which system costs are included for actual ash removal, I used the reported actual volume of ash removed from the old ash basins to the total actual volume of ash removed during the period.

- The facility-specific analysis is provided below:
    - Asheville – The expenditures for coal ash basin closure are all associated with the 1964 ash basin that was out of service in 1982. The 1982 basin was excavated by 2016 (prior to the start of the cost deferral period addressed in this case). Therefore, $99,121,747, which is the rest of the expenditures at the Asheville facility, is excluded in Step B.
    - Cape Fear – The expenditures are for four basins that were out of use by 1985 and one basin that was used until 2012 when the facility was closed. The proportion of ash in the four older basins which were out of use by 1985 relative to the total volume of ash in all of the basins is 51%. This results in the exclusion of $21,311,162 in Step B.
    - HF Lee - The expenditures are for three basins that were out of use by 1980 and one basin that was used until 2012 when the facility was closed. The proportion of ash in the three basins which were out of use by 1980 to the total volume of ash in all of the basins is 27%. This results in the exclusion of $23,632,777 in Step B.

- Mayo – The Mayo facility only has one ash basin. The Mayo ash basin continued to receive coal ash until recently. Based upon this timeline, I did not exclude any costs for coal ash basin closure in Step B.
- Robinson – The Robinson facility only has one ash basin. The Robinson ash basin continued to receive coal ash until the facility was retired in 2012. Based upon this timeline, I did not exclude any costs for coal ash basin closure in Step B.
- Roxboro – The East Ash Basin had reached capacity and was essentially out of use by 1983. The proportion of ash in the East Ash Basin, which was out of use by 1983, to the total volume of ash is 35%. This results in the exclusion of $5,303,428 in Step B.
- Sutton – The former ash disposal area (also referred as the Lay of Land Area) was out of use by 1972, and the Old Ash Basin was essentially out of use in 1985. The proportion of ash removed in the former ash disposal area and Old Ash Basin to the total volume of ash removed during the period of the requested system costs is 46%. This results in the exclusion of $47,210,482 in Step B.
- Weatherspoon – The Weatherspoon facility only had one ash basin. The Robinson ash basin continued to receive coal ash

until the facility was retired in 2011. Based upon this timeline, I did not exclude any expenditures for coal ash basin closure in Step B.

- In Step B, a total of $196,579,596 is excluded from the expenditures deferred for system-wide CCR closure activities between 9/1/17 to 6/30/17, as identified in Ms. Bednarcik's direct testimony.
- Adding the costs in Step A ($3,481,096) to those in Step B ($196,579,596) results in a total excluded cost amount of $200,060,692 through the combined Steps A and B. Through these Steps, the non-excluded amount is $215,876,813 which is calculated by taking the total amount from Ms. Bednarcik's testimony of $415,937,510 and subtracting the Step A and B excluded amount of $200,060,692.

<u>Step C</u>

In Step C, I used the remaining non-excluded costs of $215,876,813 and then estimated the reduction in costs if DEP had responded earlier to the presence of groundwater impacts at its coal ash basins. I assumed that the activities that DEP is requesting cost recovery for at this time are similar to the activities that would have been conducted at an earlier time. After reducing the expenditures for system-wide CCR closure activities during the deferral period for the amounts excluded for permanent water system costs in Step A, and for costs at older basins in Step B, I applied an adjustment to the balance to reflect the time value of money between the time when DEP knew it had issues with groundwater contamination, and when it started planning for basin closure in 2014. These calculated costs probably underestimate the reduction in costs because lower-cost options would most likely have been available at those earlier times than are being implemented at present. Because DEP was aware of the issues with groundwater contamination at its ash basins as early as the late 1980s, but failed to respond until 2014 or later when substantial planning for basin closure finally began, I have calculated the approximate reduction in system costs, starting with the expenditures identified in Ms. Bednarcik's testimony, as follows:

Taking into account the time value of money starting at different points from 1992 until 2009:

- Approximately $90.7 million is the additional cost reduction measured from 1992 (when groundwater contamination was already known to exist for several years)
- Approximately $75.7 million is the additional cost reduction measured from 1996 (when groundwater contamination claims were made by DEP to its insurance company)
- Approximately $17.7 million is the additional cost reduction measured from 2009 (when groundwater impacts were confirmed at all DEP facilities as a result of USWAG monitoring)

- These calculations start with the net costs, i.e., the expenditures for system-wide CCR closure activities during the deferral period in Ms. Bednarcik's testimony reduced by Steps A and B ($215,876,813). The reduction for the time value of money applies the average inflation rate from the particular start time noted above to the end of 2014 to account for the DEP delay in addressing the ash basins until 2015. The average rates of inflation used in the calculations are as follows:
    - 1992-2014: 2.40%
    - 1996-2014: 2.30%
    - 2009-2014: 1.44%
- The range in excluded costs for Step C ($17.7 million to $90.7 million) is then added to the excluded costs from Steps A and B ($200,060,692) to determine the range in excluded costs as follows:

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

- These reductions in costs are conservative estimates of the impact of DEP's delay in responding to evidence of groundwater impacts at its basins. For example, they do not account for lower cost alternatives that may have been available if closure had started earlier. Furthermore, they do not reduce the costs (called "NonARO" costs by Duke's accounting witness)[9] for capital expenditures at DEP's active coal plants that are required for coal ash basin closure such as dry ash conversion costs, installation or rerouting of piping for other wastewater streams prior to closure, retention ponds for other wastewaters, and/or treatment systems for wastewaters that could no longer be placed in the ash basin ponds, etc. Because these NonARO costs are also tied to the timing of ash basin closure, it is reasonable to conclude that these NonARO costs should also be reduced by the time value of money. These quantify the minimum adjustments related to the deferred system costs that DEP is seeking today as compared to the cost if responsive action had begun in a reasonable time frame.

Summary

In summary, if DEP had 1) avoided the need to provide permanent water supplies by identifying receptors and responding to evidence of groundwater impacts from its ash basins, 2) closed its ash basins earlier for those that were out of use by 1990, and 3) responded in a timely manner to evidence of groundwater impacts, DEP's system costs would have been reduced by somewhere between **$218 million to $291 million** for CCR closure activities.

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[9] See Smith Pre-filed Direct Testimony at 21, Application DEP E-1-10 Attachment NC1101 p 1, https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=3b0c187b-da4f-4d4c-9941-84ad4507f55e at 123.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

Yes.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1219A

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Energy Progress, LLC For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina	)))))	**ATTORNEY GENERAL'S OFFICE'S CORRECTIONS TO DIRECT TESTIMONY OF STEVEN C. HART, PG**

CORRECTIONS TO THE DIRECT TESTIMONY OF STEVEN C. HART, PG

Mr. Hart's direct testimony should be corrected as follows:

1. Page 71, line 7 – DEP should be changed to DEQ.
2. Page 72, line 23 – "New Ah Basin" should be changed to "New Ash Basin."
3. Page 81, line 8 – the word "concurrence" should be changed to "occurrence."
4. Page 170, line 23 – the word "Robinson" should be changed to "Weatherspoon."

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1219A

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	**ATTORNEY GENERAL'S OFFICE'S**
Application of Duke Energy Progress, LLC	)	**REVISED CORRECTIONS TO**
For Adjustment of Rates and Charges	)	**THE DIRECT TESTIMONY**
Applicable to Electric Service in North	)	**OF STEVEN C. HART, PG**
Carolina	)	

REVISED CORRECTIONS TO THE DIRECT TESTIMONY OF STEVEN C. HART, PG

Mr. Hart's direct testimony should be corrected as follows:

1. Page 2 – in the third boxed area, the Average Interest Rate should say "2009-2014" instead of "1996-2014."
2. Page 64, line 6 – The sentence which starts "As previously noted . . ." should read "The DEP Asheville, Cape Fear, Mayo, and Roxboro facilities are located in the Piedmont and Blue Ridge regions of North Carolina."
3. Page 71, line 7 – DEP should be changed to DEQ.
4. Page 72, line 23 – "New Ah Basin" should be changed to "New Ash Basin."
5. Page 81, line 8 – the word "concurrence" should be changed to "occurrence."
6. Page 170, line 23 – the word "Robinson" should be changed to "Weatherspoon."

Summary of STEVEN C. HART, PG
in
Duke Energy Progress, Docket No. E-2, Sub 1219

My name is Steven Hart and I am testifying on behalf of the North Carolina Attorney General's Office with regard to coal ash basin closure-related costs incurred in the timeframe for which Duke Energy Progress (DEP) is seeking cost recovery in this rate case – September 2017 through February 2020. I am the President and Principal Hydrogeologist of the environmental consulting and engineering firm Hart & Hickman, PC, which has offices in Charlotte and Raleigh. I am, by education, training, and experience an environmental scientist and hydrogeologist. I am a Licensed or Professional Geologist in a number of states including North Carolina and South Carolina. I have over 30 years' experience assessing and remediating contamination of environmental media such as soil and groundwater primarily in North Carolina and South Carolina, but also throughout the United States. I frequently provide consulting services to clients on regulatory compliance issues with regard to soil, sediment, surface water, and groundwater contamination.

My testimony focuses primarily on answering the following questions:

First, given the information that DEP knew or that was reasonably discoverable to DEP with regard to groundwater conditions at its coal ash basins prior to the adoption of specific regulatory requirements in North Carolina's Coal Ash Management Act ("CAMA") in 2014 and the Environmental Protection Agency's (EPA's) Coal Combustion Residuals (CCR) regulations in 2015, did DEP undertake reasonable and prudent actions and practices in a timely manner to address storage and disposal of CCR and closure of its coal ash basins before the Dan River release occurred in 2014?

Second, how would costs that DEP is seeking for coal ash-related activities likely be different today if DEP had initiated actions sooner to address its ash basin practices?

Groundwater contamination from unlined coal ash basins such as those present at the DEP facilities results from multiple factors, including the presence of high concentrations of metals which can leach from the coal ash into groundwater, the presence of a higher hydraulic head in the ash ponds as compared to groundwater which drives metals present in the coal ash basins into groundwater, and changes in groundwater chemistry that occur from the presence of the ash basin which can enhance the solubility and mobility of metals.

Once groundwater contamination is detected, North Carolina has specific rules that address the assessment and remediation of contamination known as the "2L Rules". The 2L Rules were first promulgated in 1979 and include numerical standards for compounds known as the "2L Standards". In accordance with the 2L Rules, concentrations above the 2L Standards warrant action including notification to the Department of Environmental Quality ("DEQ"), establishing background concentrations for naturally occurring compounds, termination and control of the source or sources causing the violation, mitigation of hazards from exposure to the pollutants, and corrective action to restore the quality of groundwater to the standards.

The knowledge base concerning the impact to groundwater from unlined coal ash basins increased over time from the 1980s to the mid-2000s. The utility industry, including DEP, knew about the reasonable potential for contamination of groundwater from coal ash basins as early as the 1980s. By the late 1980s, as a result of groundwater contamination concerns at the DEP Sutton facility, DEP was aware that 1) DEQ had significant concerns about the presence of groundwater contamination from coal ash basins, 2) a clay bottom liner installed in a new ash basin by DEP was a potential method to minimize the potential for groundwater impacts, 3) if concentrations of compounds in groundwater were elevated from a coal ash pond but did not exceed the groundwater standards, they were still of concern to DEQ and needed to be evaluated further, and 4) groundwater impacts at and beyond the compliance boundary from coal ash basins did occur. By the early 1990s, DEP knew that by modifying its coal ash facilities, it could decrease metals concentrations in water and protect the environment. Discharge of selenium from the coal ash basins at the Roxboro facility affected fish reproduction causing a decline in fish populations in Hyco Lake in the 1970s and 1980s which subsequently resulted in a fish consumption advisory for Hyco Lake in 1988. In approximately 1990, DEP installed a dry ash handling system to meet new permit limits for selenium, which improved water quality and resulted in a complete rescission of the fish advisory in 2001. Nonetheless, when groundwater impacts were identified in the area of the coal ash basins at the Roxboro facility in 2000, similar responsive remedial actions could have been taken but were not. Further, at the DEP Robinson and Weatherspoon facilities, groundwater monitoring had been conducted as early as the early to mid-1990s and indicated groundwater contamination issues with coal ash disposal areas.

By the early 2000s, as a result of an EPA Regulatory Determination concerning the management of CCRs, it was clear that EPA's documentation of damage cases from coal ash basins and their assessments of environmental impact would lead to increased scrutiny, environmental sampling, and potential closure of ash basins. In 2006, the Utility Solid Waste Activities Group (USWAG), of which DEP was a part, issued an "action plan" to address EPA's concern about groundwater impacts from coal ash basins. The USWAG action plan was the electric utility industry's <u>commitment</u> to adopt groundwater performance standards at facilities that manage CCRs and to implement a comprehensive monitoring program to measure conformance with the groundwater standards at facilities that managed CCRs in an effort to avoid mandatory federal requirements.

In 2006 through 2008, DEP implemented groundwater monitoring at its ash basins as part of the USWAG action plan. Most of the groundwater monitoring was performed within the compliance boundary of the coal ash basins at the North Carolina facilities. The results of this monitoring provided irrefutable evidence of groundwater impacts associated with the coal ash basins. The USWAG action plan indicates that, on detecting groundwater impacts, DEP should have worked with the regulatory agency to further assess conditions and, as needed, develop corrective action programs. Instead, DEP submitted the data to DEQ without evaluation or responsive action and implied that the data were consistent with background conditions, even though that implication was not supported by the data.

The detection of compounds above 2L Standards in groundwater near the coal ash basins at North Carolina DEP facilities or MCLs at the South Carolina DEP facility should have triggered a real evaluation of background conditions, installation of wells at the compliance boundary for the North Carolina facilities, and additional monitoring wells to define the extent of impacts. However, rather than being proactive with regard to groundwater contamination at its coal ash basins, DEP chose to wait until regulatory agencies noted groundwater contamination concerns from DEP's data submittals in the 2009 to 2010 timeframe. Even after wells were installed along the mandatory compliance boundaries of the ash basins at DEQ's direction in 2011, DEP continued to indicate as late as 2013 that it strongly believed that the iron and manganese exceedances were the result of background concentrations. However, the actual data did not support the conclusion that the exceedances were consistent with background concentrations.

It is evident from my analysis that, as a result of groundwater monitoring data and increased concern with groundwater contamination from coal ash basins, DEP should have taken responsive action sooner and initiated a systematic plan to address its coal ash basins by converting facilities to dry ash handling, eliminating other wastewater streams, closure planning, and evaluating methods to reduce environmental impact while the basins were still operational. This would have required an expenditure of funds earlier, but would have reduced long term risks and liabilities which would have led to lower costs being requested at this time and the imposition of those costs on DEP's ratepayers at that time.

In 2013 and 2014, Duke Energy documents acknowledged that DEP did not yet have any approved closure plans and that it had failed to make "reasonable efforts" toward the closure of ash basins. It was not until after the Dan River release in February 2014 that DEP committed, under regulatory pressure, to implement full assessments, closure evaluations, some dry ash handling conversions, and closure activities on an expedited basis.

As a result of the Dan River release, North Carolina enacted CAMA in 2014. Soon thereafter, in 2015, EPA issued its CCR Rule. Both of these regulations address closure of coal ash basins and bring greater certainty about the management and closure of coal ash ponds in compliance with Groundwater, Surface Water, and Solid Waste requirements. However, for many years prior to these newer requirements, there was no ambiguity about the requirements of North Carolina's 2L Rules. When groundwater contamination is detected in association with a permitted ash pond – i.e., if a 2L Standard for a compound is exceeded -- the 2L Rules require that the responsible party determine the nature and extent of the contamination, terminate and control the discharge, mitigate hazards, perform receptor surveys to identify potential receptors of the contamination, and propose and implement corrective actions. This lack of ambiguity about requirements of the 2L Rules is confirmed by DEP's statements to its insurance carriers in 2011 which advised that, regardless of when EPA may act or what other states may do, 1) North Carolina is taking aggressive action on coal ash facilities, 2) there are existing regulations (i.e., the North Carolina 2L Rules for groundwater) that describe the corrective action process if there are exceedances at the compliance boundaries, 3) North Carolina regulations already provide for the same potential closure scheme as EPA's proposed rules, and 4) State orders on remediation stemming directly from ash basin contamination seem "inevitable.".

DEP's inattention to groundwater contamination issues and delay in responsive actions to its coal ash basins prior to the Dan River release increased the cost today as follows:

1) DEP's actions and failure to take actions before the Dan River spill prompted the adoption of environmental requirements that imposed accelerated schedules to address coal ash basin problems, particularly at the Asheville and Sutton facilities, and costs for accelerated actions are almost always greater than costs under non-accelerated timeframes.
2) Most of the expenditures that DEP seeks to recover for coal ash basin closures and CCR disposal were incurred at coal plants that are retired and have not been used for several years to produce power for ratepayers. In fact, the only DEP coal fired facilities that were still in operation at the time of the Dan River spill in 2014 were the Asheville, Mayo, and Roxboro facilities. Had DEP taken actions sooner to address its coal ash basins by engaging in reasonable monitoring and taking adequate responsive actions, some of the costs would have been included in the cost of service for customers while the coal plants were in use.

3) In addition, substantial parts of the expenditures that were incurred to close ash basins for which DEP is seeking cost recovery are for basins that had not been in substantial use for decades and were functionally full, but which continued to contribute to groundwater impacts after they were essentially out of use.
4) In the absence of an indication that DEP accrued and set aside monies for these activities, DEP's costs are higher today due to inflation.

In addition, the requirement that Duke connect all households to alternate water supplies was likely a result of DEP's delay in addressing groundwater impacts. Prior to the Dan River release, DEP maintained that there were no longer drinking water wells impacted by the DEP facilities, but it is unheard of for a company to have to connect properties to alternate water when those water supplies are not impacted. In my opinion, this requirement that DEP provide permanent water supplies was warranted by law because DEP, once it knew it had groundwater issues, had failed to determine the extent of groundwater impacts, reliably establish background concentrations, and perform adequate receptor evaluations. Instead, DEP contended that there were few if any water supply well receptors in the area of its facilities and maintained that position despite there being no indication that it performed comprehensive receptor surveys until required to do so under CAMA. Thus, it appears that these costs were directly related to DEP's delay in evaluating groundwater impacts.

The determination of the increased costs that DEP incurred as a result of its delays in corrective action is difficult to determine because of the number of factors involved. Therefore, I used a simplified approach by:

1) Removing the water supply connection costs of $3,481,096 for the reasons noted above.

2) Removing the estimated portion of the ash basin closure costs associated with closure of ash basins that were taken out of service in the 1960s to 1980s but had not been previously closed at the Asheville, Cape Fear, HF Lee, Roxboro, and Sutton facilities. It is reasonable to conclude that today's ratepayers should not have to pay for closure of coal ash basins that were essentially out of use and functionally full in the 1960s to 1980s for which they derived no significant benefit and which continued to contribute to groundwater impacts after they were essentially out of use. This resulted in additional excluded costs of $196,579,596.
3) After removal of the above two cost elements, I de-escalated the remaining non-excluded costs by considering the inflation rate between 2014 when it started planning for basin closure and different times starting from 1992 to 2009 when DEP knew it had issues with groundwater contamination. This resulted in additional excluded costs ranging from $17,735,012 to $90,679,573. These calculated costs are likely to underestimate the cost reduction because lower cost options would have been available at those earlier times than are being implemented at present. Further, they do not include similar reductions in capital costs such as dry ash conversions, installation or rerouting of wastewater piping, and construction of new wastewater basins that are needed before the coal ash basins can be closed.

In summary, by adding the amounts of the three cost reduction elements above, I estimate that if DEP had 1) avoided the need to provide permanent water supplies by identifying receptors and responding to evidence of groundwater impacts from its ash basins, 2) closed its ash basins earlier for those that were out of use by 1990, and 3) responded in a timely manner to evidence of groundwater impacts, DEP's system costs would have been reduced by somewhere between $218 million to $291 million for CCR closure activities.

This concludes my summary. Thank you very much.

MS. TOWNSEND: Commissioner Clodfelter, we would also move that Mr. Hart's live testimony identified at the joint stipulation in the DEC case Docket E-7, Sub 1214 be copied into the record as if given orally on the stand, and the transcript pages are at transcript Volume 16, page 838, line 1 through page 944, line 8; and transcript Volume 17, page 15, line 5 through page 80, line 19.

COMMISSIONER CLODFELTER: You've heard Ms. Townsend's motion. Are there objections from any party?

(No response.)

COMMISSIONER CLODFELTER: Hearing none, the motion is allowed.

(Whereupon, the testimony from Docket Number E-7, Sub 1214, Volume 16, page 838, line 1 through page 944, line 8; and Volume 17, page 15, line 5 through page 80, line 19 were copied into the record as if given orally from the stand.)

A Good morning.

Q Mr. Hart, we'll be referring to a number of exhibits, but one I know we'll be referring to in particular is your -- a transcript of your deposition which was taken on, I think, the second of March, which was previously marked as Duke Exhibit 4, DEC Exhibit 4. So if you could just have that handy, that would be really good.

MR. MEHTA: And Chair Mitchell, I would like to go ahead and identify for the record DEC Exhibit 4 as Hart DEC Cross Examination Exhibit Number 1.

CHAIR MITCHELL: All right. Bear with me one minute, Mr. Mehta, while I get the document. All right. The document will be so marked.

MR. MEHTA: Thank you, Chair Mitchell.

(Whereupon, DEC Hart Cross
Examination Exhibit Number 1 was
marked for identification.)

Q Mr. Hart, this is your first appearance before the North Carolina Utilities Commission, right?

A That is correct.

Q And I'm going to refer to it, I think, probably throughout this examination as the Commission, and you'll understand what I mean when I say the Commission, correct?

A Yes, I will.

Q And you understand, Mr. Hart, that the Commission is not an environmental regulator; is that right?

A That is my understanding, yes.

Q And, in fact, Mr. Hart, in -- in North Carolina, the environmental regulator for Duke Energy Carolinas is the North Carolina Department of Environmental Quality, correct?

A That and EPA, yes.

Q And if I refer to the North Carolina Department as the DEQ, no matter what its name was at whatever the time frame was in which we're talking about it, you will understand what I'm talking about, correct?

A Correct.
Q The Utilities Commission does not regulate coal ash storage or disposal, does it?
A I don't know that.
Q Well, look, if you would, Mr. Hart, at DEC Exhibit 7.
MR. MEHTA: Chair Mitchell, I would like for DEC Exhibit 7 to be identified for the record as Hart DEC Cross Examination Exhibit 2.
CHAIR MITCHELL: All right, Mr. Mehta. We will identify the document as DEC Hart Cross Examination Exhibit 2.
(Whereupon, DEC Hart Cross Examination Exhibit Number 2 was marked for identification.)
Q Mr. Hart, what is now marked and identified as DEC Cross Examination Exhibit 2 is actually directly from the Commission's website. Do you see that?
A I see a copy of it, yes.
Q And there's two columns at the top of the page under the heading Electricity. Do you see that?
A Yes.
Q The one on the left says the NCUC, which is the Commission, Regulates, and the one on the right says the

NCUC Does Not Regulate. Do you see that?

A Yes. I do see that.

Q And there is a number of bullets under the heading that it Does Not Regulate. The second-to-last bullet is that the Commission does not regulate coal ash storage or disposal. Do you see that?

A Yes.

Q And right under that, the Commission also does not regulate air or water emissions from power plants. Do you see that?

A Yes.

Q And both of those things, Mr. Hart, are the responsibility, in terms of regulation of DEC in North Carolina, the responsibility of the DEQ, correct?

A I would say the DEQ and the United States Environmental Protection Agency, yes.

Q Okay. And just to be clear, I guess the EPA delegates to the DEQ watch authority that the EPA has with respect to coal ash or water emissions from power plants. Am I understanding that correctly or am I wrong about that?

A Well, they do for the most part, but, for example, the Dan River spill, of course, EPA was heavily involved with, and it's certainly related to coal ash storage and disposal and releases. So there are cases where the EPA feels like they need to be involved, and they may come and join in with the DEQ to address certain issues.

Q I understand, but in the sort of normal everyday run-of-the-mill operation of the power plants that are run by DEC, the DEQ has delegated authority from the US EPA to oversee and regulate the operation of the power plants, correct?

A I would say from an environmental standpoint, for the most part, yes.

Q And in terms of water emissions from the power plants, that regulation occurs in the context of a permit program, correct?

A Could you explain what you mean by "water emissions"?

Q Well, I guess what I mean is the -- let me back up and say it this way. There is a program called the National Pollutant Discharge Elimination System, or NPDES, correct?

A That is correct.

Q And that program is administered in North Carolina by the DEQ, correct?

A Correct.

Q And the Duke Energy Carolinas power plants, and we're really talking about the coal-fired power plants in terms of what we're talking about today, to the extent that they operate with NPDES permits, that program is administered and regulated by the DEQ; is that correct?

A Yes, with authority from the EPA.

Q And that's a direct delegation of authority from the EPA, correct?

A That's my understanding, yes.

Q Now, Mr. Hart, the Utilities Commission does not regulate groundwater quality, does it?

A I don't believe so.

Q And that also is the responsibility of the DEQ, correct?

A Correct.

Q And the Utilities Commission does not regulate when groundwater monitoring wells should be installed, where and to what depth they should be installed, or how frequently and for what parameters those wells should be sampled, does it?

A I don't believe so, no.

Q And those things also are the responsibility of the DEQ, correct, in North Carolina?

A Well, they would be the responsibility of the

Companies that are responding or addressing the environmental issues in accordance with the laws of the State of North Carolina, the environmental laws, which are overseen and -- by the DEQ.

Q Okay. So the DEQ is the regulator involved in issues of when groundwater -- groundwater monitoring wells should be installed, where and to what depth they should be installed, or how frequently and for what parameters those wells should be sampled, isn't it?

A No. I would disagree with that.

Q And you would disagree with that why?

A Well, the DEQ doesn't necessarily make those decisions. It's up to the individual company to make those decisions. In some cases, DEQ isn't involved at all in some of those decisions, except to the individual companies that are regulated by the groundwater standards or the surface water standards or something of that nature to determine, if we're talking about a groundwater issue, where to put wells, how deep to put wells, in accordance with the rules and in order to comply with the rules.

Q Do you -- are you saying that the DEQ has no involvement in those kinds of issues, Mr. Hart?

A No, I didn't. What I'm saying is, is that the

Companies have primary responsibility. The regulated people of the state have the primary responsibility to determine where to put wells, how deep to put the wells and those kind of things. The state might oversee and provide comments, but in most cases it's not a dictation of thou shalt do this. It's a self-implementing in some cases -- a groundwater assessment or remediation can be self-implemented. Certainly, there are procedures in place for the State to provide feedback, comments, and if not in compliance, notice of regulatory requirements or notices of violation, but it's not the sole responsibility of DEQ to make those decisions.

Q No. I understand, Mr. Hart, that it's not the sole responsibility of the DEQ to make those kinds of decisions, but it would be very foolish of a company to make those decisions on its own without involving the DEQ, would it not?

A No. In fact, there's certain programs within North Carolina like the Inactive Hazardous Sites Program, the Registered Environmental Consultant Program, where you get no feedback from DEQ with regard to where to put wells and you don't involve DEQ at all. And so it is not necessarily prudent to do that because you have an obligation to define the horizontal and vertical extent of groundwater contamination, you have an obligation to clean that groundwater contamination up, and so you may want to accrue those along the way, but it's not necessarily prudent to get approvals from the State in all steps of what you're doing.

Q Well, Mr. Hart, if you set aside the Inactive Hazardous Waste Program and the -- whatever you mentioned in terms of the -- of the process by which those decisions are made, and you just talk about the monitoring of groundwater in conjunction with NPDES permits that the DEQ has issued, which occurred at Duke Energy power plants, did it not?

A I'm sorry, I wasn't talking -- were you asserting I was talking about NPDES permits?

Q No. I think you said -- you mentioned that you were talking about there are programs in which the DEQ is not involved at all, like the Inactive Hazardous Waste Program, correct?

A Correct.

Q Okay. The Inactive Hazardous Waste Program has nothing to do with any of the groundwater monitoring that DEC did at its power plants, you know, back from the mid-1980s forward, does it?

A Not that I'm aware of, not DEC, no.

Q Okay. So if you set aside that self-executing program, the Inactive Hazardous Waste Program that you talked about, Mr. Hart -- and I take it you've advised clients in your -- in your role as a consulting hydrogeologist how to run a groundwater monitoring program, haven't you?

A Certainly, yes.

Q And you've done that in the -- in the context of the groundwater monitoring -- the same type of context of the groundwater monitoring that has gone on at DEC power plants since the mid-1980s, correct?

A Correct. Similar context, yes.

Q And is it your practice, Mr. Hart, to advise clients that in setting up a monitoring program in that context that they should ignore the environmental regulator?

A No. I never said they should ignore the environmental regulator, but you don't have to, every step along the way, get approval from DEQ. If you have a groundwater contamination, for example, you determine where the wells go, you determine where the spring intervals are, you determine the analyses. Now, that may be, in some cases, done in conjunction with DEQ, but if you find an issue, you send those in in a report, typically, that identifies where you have contamination and it may recommend some additional assessment that needs to be done, but you, in general, in my experience, try to proactively deal with these issues. You don't just send in data and then sit back and wait for the regulars (sic) to come -- the regulators to come back and review it.

Q Mr. Hart, would you look at your Exhibit 28?

A One second. Okay.

Q Just tell me when you're there.

A Yes. I'm there.

Q And Exhibit 28 is an email from Allen Stowe at Duke Energy to various people reporting on groundwater well installation at the Allen Steam Station, and the email is dated August 13, 2004, correct?

A Correct.

Q And this -- this email is in the context -- and we'll get to this later, I think, in the examination, Mr. Hart, but in the context of the voluntary groundwater monitoring program that Duke Energy Carolinas implemented as part of the USWAG, and that's U-S-W-A-G, and you can remind me what the acronym stands for, if you would, Mr. Hart.

A It's the Utilities Solid Waste Activities

Group.

Q Thank you. So as part of that voluntary USWAG groundwater monitoring program, correct?

A Well, the -- as I understand it, the work they were doing at the Allen plant in 2004 was as part of the USWAG action plan.

Q Okay. And if you would, Mr. Hart, the second paragraph of the email notes -- well, actually, I believe the first paragraph, the very first line, notes that various people met with Bill Goforth of the DEQ, correct?

A Yes.

Q On August 12, 2004, correct?

A Correct.

Q And Mr. Allen (sic), in the second paragraph, you know, reports on that meeting, correct?

A Mr. Stowe?

Q Mr. Stowe. Excuse me.

A That's all right. Yes. Yes, he does.

Q And he says, "After a brief review of site maps by Bill Miller and Don Scruggs, a tour of the ash basin and the surrounding areas was given," correct?

A Yes. That's correct.

Q And he says, going forward, Mr. Goforth stated that the Company could, you know, investigate a certain area at the -- at the -- of the plant with -- "with minor modifications," correct?

A Well, he said, too, there are preexisting wells, so obviously there are wells already there that DEQ apparently didn't have any say in previously. So he says there are preexisting wells that could potentially be used in the USWAG monitoring plan, but also that he concurred with the location and proposed depths of some additional monitoring wells.

Q So that -- and that's in the following sentence. "Mr. Goforth concurred with the location and the proposed depths (well pair - one shallow, one deep) for the background and the two monitoring wells located closest to the locations where the ash basin is located near residences," correct?

A Correct. That's what it says, yes.

Q And it goes on to say that "Mr. Goforth requested that two additional monitoring wells be sited between the western side of the ash basin and the housing development" -- that NC; well, we'll just call it DEQ -- "and Gaston County officials will be contacted to ascertain" -- "permit requirements," et cetera. Do you see that?

A Yes.

Q So Mr. Goforth was consulted about the location of wells approved --

A Yes, yes.

Q -- in some -- in some fashion about the location, depth of the wells, correct?

A Yes, yes.

Q And suggested additional wells be placed in an additional site, correct?

A Correct.

Q And this is a very normal way that regulated entities interact with their regulators when deciding on a groundwater monitoring program, isn't it?

A It can be, yes. I think this is the only facility that they met with DEQ. That's the only facility that I have seen where they met with DEQ and discussed the well installation --

Q But you don't -- you don't --

A -- is the Allen plant.

Q You don't know if they also discussed the well placement with DEQ at the other facilities, do you? You don't know one way whether or not they ever met with DEQ with regard to well placement at the other facilities, do you?

A Well, like I said, I've seen no indication of it, no. And, in fact, DEQ had a number of issues with the well placements when they submitted data in 2009. Some of the wells were not installed in upgradient locations. Some of the wells that DEC claimed were up -- back -- downgradient wells were actually upgradient. So it's hard for me to believe that DEC did, in fact, know about the location of all the wells that were installed because DEC -- DEQ, I'm sorry, actually asked for maps that shows where the well -- the locations of the wells were in 2009. They didn't know where these wells were being installed.

Now, they did get Mr. Goforth's opinion in 2004, which was a good procedure. They also told him that they were going to install monitoring wells at the rest of the facilities in 2005 and 6, which did not occur. In fact, some of the wells at some of the DEC facilities were not installed in 2008. And --

Q They were -- they were --

A -- not only that, but the wells that were installed near the residences showed contamination, and DEC did nothing about it.

Q Okay. The wells that you say should have been installed in 2006 were ultimately installed, were they not?

A They were installed as late as 2008, yes.

Q Okay.

A And then they didn't follow the USWAG action plan when they had data. The USWAG action plan was very specific about what to do. It said if you have groundwater exceedances, you're supposed to work with the State regulatory program to come up with a plan and do corrective action. And they, in 2004, in this very email that you -- said we want to be proactive about this issue, and that's not what happened.

Q Yeah. We'll get -- we'll get there, Mr. Hart. Don't worry.

A Well, I already got there.

Q You'll have your opportunity to wax eloquent and all that, but let me -- let me circle back for a moment. And we were talking about the various responsibilities of the DEQ involving coal ash storage and NPDES permits and things of that nature, and that's, of course, in North Carolina, correct?

A That's correct.

Q And the equivalent agency for South Carolina is the South Carolina Department of Health and Environmental Control, correct?

A That's correct.

Q Which is called DHEC, right? Is that what you call it?

A Yes. That's correct.

Q Now, Mr. Hart, you are a, I think, a hydrogeologist by training, correct?

A By education and training and experience, yes.

Q You're not a utility engineer, correct?

A No, I am not.

Q And, in fact, you're not an engineer at all, correct?

A That's correct.

Q And you've never designed a coal ash basin or a power plant associated with a coal ash basin, have you?

A No.

Q And you've never operated a coal ash basin or its associated power plant, have you?

A No.

Q And you are aware, are you not, Mr. Hart, that each of the coal ash basins for which the Company is seeking cost recovery in this proceeding was unlined when it was constructed, correct?

A That's my understanding, yes.

Q And if you would, Mr. Hart, go to your deposition which we marked for purposes of this proceeding as Cross Examination Exhibit 1, and particularly to page 6 of that deposition.

A Okay.

Q And I asked you at line 16 of page 6 about testimony received in the -- in Duke Energy Carolinas last rate case from the Attorney General witness Dan Wittliff. Do you see that?

A Yes, I do.

Q And you indicated that you, in fact, had not reviewed the testimony of Mr. Wittliff, correct?

A That is correct.

Q And if you go on to page 7 of the deposition, Mr. Hart, I asked you if you were aware that Mr. Wittliff was asked by the then Chair of the Utilities Commission about whether it was his view that the Utility that used unlined ponds, if that Utility was imprudent when it first sluiced coal ash to the impoundments that were unlined. Do you see that?

A Yes.

Q And you -- after a lot of back and forth with Ms. Townsend, I think if you flip over to page 8 of your deposition --

A Okay.

Q -- and I asked you on line 5 if you would accept, subject to check, that the Chairman of the Commission did ask that question of Mr. Wittliff. Do you see that?

A Yes.

Q And that Mr. Wittliff responded, this is line 12, "...no, the law allowed them to do it and the law continued to allow them to do it, even though there was" -- a -- "concern." Do you see that?

A Yeah. Do you have the actual testimony that I could review? I believe that is something that Mr. Marzo asked for yesterday, the actual testimony, rather than just a subject to check?

Q Well, we can get it for you if you'd like, but that really wasn't the purpose of my question. I'm not -- let me ask you this, did you check after the deposition whether or not Chairman Finley at the time asked the question and Mr. Wittliff answered it in that way?

A I did not.

Q Okay. And then I asked you, Mr. Hart, at line 17 if you agreed or disagreed with Mr. Wittliff, correct?

A Yes, subject to check, that's exactly what he said, which I don't have it in front of me and never have been shown.

Q And, actually, your answer to that question, Mr. Hart, was that you hadn't formulated an opinion about that, correct?

A That's correct.

Q And I asked you if there was a reason you hadn't formulated an opinion about that, correct?

A That's correct.

Q And on line 22 you said "It wasn't part of my scope of work," correct?

A Correct. What I looked at was when DEC was aware of groundwater contamination, violation of the 2L standards and the 2L rules, what actions did it take, and when there was -- you know, after they first determined that there was contamination associated with the ash basins.

Q And that's essentially what you said. Following "my scope of work," you said, "I looked at groundwater contamination associated with the basins," correct?

A Correct, yes, and DEC's response to the groundwater contamination.

Q So you still today have no opinion one way or the other or agreement one way or the other with whatever Mr. Wittliff said in the last proceeding, correct?

A Again, I'm not sure what Mr. Wittliff said in the last proceeding.
Q Now, when you -- if I'm looking at -- at your -- well, I'm looking at your deposition testimony, lines 22, 23 on page 8, where you say that your scope of work was really associated with groundwater contamination associated with the basins. What, Mr. Hart, do you mean by "contamination"?
A Well, contamination typically is something above background for a naturally occurring substance, or in any detectable quantity if it's a manmade substance.
Q Is that what --
A And so we also compare that to the standards as well. So you can have contamination that's not above the standard. You can have contamination that's below the standard.
Q Well, I guess my question to you, Mr. Hart, is what do you mean by "contamination" when you said that your scope of work was to look at groundwater contamination associated with the basins?
A Well, I mean, I think I answered that. It's -- contamination is something in groundwater that's either above background concentration, or if it's a manmade substance something that's there in a detectable

concentration. Now, that's contamination. It could be above or below the standard in some cases. And, of course, in coal ash basins, you know, there is a compliance boundary, too, but there's still contamination even if it's within, for example, compliance.

Q And so, I mean, if you take it to the extreme, Mr. Hart, you would say one molecule above the standard, whatever the standard is, is "contamination"?

A Well, I don't know that you could detect one molecule, so it's got to be detectable.

Q Well, if you could detect one molecule, one molecule above the standard would, under your definition, be contamination, correct?

A That would be -- yes, but, again, it's compared to the standard. So in some cases contamination is not a concern if it's below the standard. It would be a concern if it's above the standard.

Q Okay. But it's contamination, nonetheless, the way you have defined contamination, even if it's below the standard, if it wasn't supposed to be there to begin with, correct?

A The way I've defined it, yes.

Q So you're not -- you're not defining contamination for purposes of your testimony the way --

the way that EPA would define, for example, environmental damage or environmental harm, correct?

A I don't know what their definitions are. If you could show me something, I'd be, you know, glad to look at what their definition is.

Q Well, do you have available to you Ms. Marcia Williams' testimony?

A Yes. I have it.

Q If you would turn with me, Mr. Hart, to page 80 of her testimony.

A Okay.

Q And specifically to Footnote 104. Do you see that?

A Okay.

Q And in Footnote 104, Ms. Williams says, "Further, the word 'contamination' in Mr. Hart's statement is also not precise or particularly useful. There is an important distinction between groundwater contamination and groundwater harm. Contamination is any level above background." That's how you're using the word contamination for purposes of your testimony, correct?

A Yes, but, you know, I compare it to the standard, yes.

Q Understood. And Ms. Williams goes on to say "This could include low levels of nitrates in groundwater below farm properties as a result of fertilizer use," correct?

A It could. I mean, the word "contamination" now would only be a concern if it was above 10 milligrams per liter, which is the standard.

Q But assuming it was above 10 milligrams per liter, you would call that contamination, correct?

A Yes. I would -- yes, contamination above the standard at a potential -- at a level of concern.

Q Okay. And Ms. Williams goes on to say "Environmental harm is levels of contamination above some type of health-based level that results in exposures to receptors that come into contact with that groundwater, whether from drinking water use or another beneficial use." Do you see that?

A Yes. I think it shows Ms. Williams' unfamiliarity with the North Carolina groundwater standards and rules. It says nothing about whether it has to have exposures to receptors. It says that if you exceed the standard, you are required to assess the cause and significance, eliminate the source, and then develop a corrective action plan. There is no statement in the

North Carolina 2L rules or standards about whether the groundwater has to come in contact with a receptor that's drinking water or some other receptor. It's not receptor-based, the groundwater standards in North Carolina.

Q Understood, Mr. Hart. I'm really just trying to establish what you mean by contamination, and that what you mean by contamination is different than what the EPA would call environmental harm, correct?

A Well, I mean, I think Ms. Williams even says contamination is any level above background. That's what -- that's how she defines it. And then she goes on to explain environmental harm. Now, she -- that's her opinion. There's no reference to this is EPA's opinion. This is her opinion. So my point is that the 2L rules don't talk about it. They talk about protecting groundwater as a resource for all citizens of the state. They don't talk about whether it has to have a receptor, because all groundwater may become a future use of groundwater and then impact a receptor.

Q Mr. Hart, if you would look at page 8 of your testimony in this proceeding, and particularly lines 5 through 7.

A My testimony?

Q Not the deposition; your -- your prefiled testimony.
A Okay. What page? I'm sorry.
Q Page 8 --
A Okay.
Q -- lines 5 through 7 --
A All right.
Q -- where you indicate that one of the results of your investigation is the conclusion that the utility industry, including DEC, "knew about the potential for contamination of groundwater from coal ash basins as early as the 1980s." Is that correct?
A Yes. That's correct. That's what it says.
Q And you're using -- your meaning of the word contamination in that testimony is the same as what you just gave us a few minutes ago, that is, some level above background, correct?
A Yes. It knew, and it shouldn't have been surprised when it put in monitoring wells and found contamination in many cases above the 2L standard. It knew that this was certainly a possibility for unlined coal ash basins, yes.
Q And, Mr. Hart, groundwater monitoring occurred at DEC -- DEC coal ash basin sites as early as 1978;

isn't that correct?

A I don't know if it's '78. I know -- the earliest I have seen is at the Allen plant, and it may have been '78 or '79, reported in, I believe, '84. But maybe, yes.

Q So if you actually -- if you look at the -- I guess it's Joint Exhibit 9 --

A Okay. I have that.

Q -- and that is the report of -- Duke Energy's report of the Allen plant monitoring program, correct?

A Yes. The investigation of the coal ash basin groundwater at the Allen plant as part of a broader EPA study. Yes.

Q And the page -- I guess they're actually -- since this was part of the appellate record from the -- from the last case, which I guess is still at the Supreme Court right now, but there's a -- there's a page number at the top of each page.

A I don't have -- I don't have that page number, but I can --

Q Oh. Well, why don't you go to page 14 of the report, then.

A Okay. I'm sorry. Yes.

Q It's also called Doc. Ex. 4909 for anybody that happens to have that -- happens to have the appellate record. And right at the top of the page, the report describes the monitoring program at Allen, correct?

A Correct.

Q And it says "A monitoring program more extensive than that required by RCRA," R-C-R-A, "has been in progress at the Allen Steam Station since 1978," correct?

A Correct.

Q And the investigations at the Allen plant and the results of those investigations were published in this report, Joint Exhibit 9, correct?

A Yes, they were. Well, a summary of them.

Q Well, they weren't keeping them under a bushel somewhere, Mr. Hart, were they? They were published.

A Well, this -- the actual data isn't published, is my point, that we have summaries of the data.

Q Okay. Was the actual data hidden somewhere?

A I don't know. It wasn't provided to anyone that I have seen the actual data to be able to verify tables and see if other, you know, constituents, for example, were analyzed for it.

Q Okay.

A So they have provided a summary of the data.

Whether that's the complete summary of the data or not, I don't know.

Q And the Allen plant also underwent additional investigation in the mid-1980s by Arthur D. Little under contract with US EPA, correct?

A Yes, yes.

Q And that data is in that report, which I think is Joint Exhibit 10, correct?

A Yes. I have not looked at that report.

Q And that report is well over 1,000 pages long, and it includes all the data that was collected in connection with the Arthur D. Little study, correct?

A I don't know that. I'm not saying it's not. I just don't have -- I haven't looked at that report.

Q And the Allen plant underwent additional investigation by a contractor for the Electric Power Research Institute, or EPRI, did it not?

A I don't know. I don't know that I have that.

Q If you would look, Mr. Hart, at Joint Exhibit 12.

A Okay.

Q And go to page 1 of that report and on to page 2. And if you have the Doc. Ex. numbers, that would be Doc. Ex. 9440 to 9441.

A I don't have that report. I'm trying to find it. I only downloaded the DEC exhibits. I wasn't aware we had -- about these joint exhibits, but --

Q So you don't have the Joint Exhibit 12?

A No, I do not.

Q Well, let me just read it to you, and we'll do this, again, subject to check, and you can check --

A Okay.

Q -- later and see --

A I could probably pull it up from like the data site, if I need to.

Q Okay. Well, I don't -- I don't know where you would find it on the data site, but the report is a report -- and it's also from the last case, Wells Public Staff Cross Examination Exhibit Number 8, if you happen to have that.

A Okay. It's for the River (sic) plant. I mean, its title is Riverbend Plant.

Q Yes. It's the Riverbend evaluation.

A Right.

Q So it's titled "Evaluation of the Effects of Ash Disposal at the Riverbend Plant of Duke Power Company on Groundwater and Surface Water Quality," prepared for Duke Power Company. There's not a date on the first page, but it's the late '80s, as I recall.

A So it's a Wells exhibit? Let me go find it.

Q Well, let me do this, Mr. Hart --

A Which one is it? I'm sorry. I think I can find it. I just --

Q Well, I don't -- I don't think it's necessary. Again, you can check me on just what I read, but it is or was also Wells Public Staff Cross Examination Exhibit Number 8 in the prior case. And I'm reading from the bottom of page 1, which is also Doc. Ex. --

A All right. I found it. I found it. I'm sorry.

Q All right.

A I did find it.

Q Doc. Ex. 9440. "Intensive studies on the effect of ash disposal have been conducted at the Allen Plant, which is also located in Gaston County about 12 miles south of the Riverbend Plant." And they indicate that Duke Power conducted a study, correct? That's the 1984 report, Joint Exhibit 9.

A Yes.

Q And they indicate Arthur D. Little conducted a study under contract with the Environmental Protection Agency, and that's Joint Exhibit 10, correct?

A Correct.

Q And they indicate that Tetra Tech, under contract with the Electric Power Research Institute, also conducted studies in July of 1985, correct?

A I'm sorry. What page are you? I don't have this Doc. on my copy.

Q I'm at --

A I have the report.

Q I'm looking at page 1 and 2 of the report.

A Okay. I'm sorry.

Q If you're looking at it on a PDF, it might -- it's probably PDF page 9 and 10.

A Okay. Yes. I'm sorry. I'm there.

Q Okay. So those -- those three studies were conducted at the Allen plant in the mid-1980s, correct?

A Correct. And for the groundwater contamination associated with the basin. In fact, that's documented in EPA's 1988 report. In fact, it says that manganese concentrations were high and unlikely to be steady state, and they expected further migration of manganese in groundwater at the Allen plant. And this, of course, is before the time when there was a compliance boundary, so any violation of the standard would be a violation of the standard.

Q Okay. Mr. Hart, if you look back at page 1 of the Riverbend report --

A Okay.

Q -- Joint Exhibit 12.

A Yes.

Q The report itself states that the "studies show that groundwater quality has not been significantly degraded by seepage from the Allen plant ash ponds," does it not?

A It says that, but that's -- that's incorrect. What the conclusion of that report was, was that the mass discharge from the Allen plant into surface water was much smaller than the flow of the adjacent river. So, yes, that's obvious, right? So the river is going to have a flow rate in thousands of cubic feet per second, and a groundwater flow might be in the range of a tenth of a cubic foot per second by a flux into -- into the river. But it didn't mean that there wasn't a problem with the groundwater. What they concluded was the groundwater that was impacted at the Allen plant wasn't having an effect upon the surface water, and that was their barometer for determining whether there was an impact, not whether the groundwater was contaminated. In fact, the data showed that the groundwater was contaminated at the ash basin at the Allen plant.

Q All right. So when they say "These studies show that groundwater quality has not been significantly degraded by seepage from the Allen plant ash ponds," are they wrong?

A Well, I think it's how you interpret the word "significantly."

Q Ahh.

A They had contamination above the 2L standards in some cases.

Q Okay. And so this is -- we're going back to, really, the -- the difference between a definition of contamination that's something above background versus something that would cause environmental harm, correct?

A Well, no. This is contamination that was above the 2L standards, but what their conclusion was is that it was attenuated to a certain extent and then it was further diluted in the river, the conclusion being that dilution is the solution to pollution, from their standpoint.

Q And that's why it's "not significantly degraded," correct?

A I don't know what they mean by that. It was above the 2L standards for several constituents. And as

I mentioned, in EPA's 1988 report they identified that manganese, I believe, was up to 120,000 parts per billion versus the standard of 50. And they say that they believe that if it's not in steady state and it will continue to mobilize because the exchange capacity or the attenuation capacity of the soil will not be sufficient to attenuate that kind of contamination.

Q Yeah. We'll get to the 1988 report, Mr. -- Mr. Hart.

A You have to dig -- you have to go deep in the 1988 report. You can't just read the conclusions.

Q Mr. Hart, the -- the -- we were talking about the groundwater monitoring program at the Allen plant that began as early as 1978, correct?

A Correct.

Q And further groundwater monitoring took place in the mid-to-late 1980s at Marshall and Belews Creek, those power plants, correct?

A I'm looking. Yes.

Q And this was in connection with NPDES permits issued in connection with the operation of those plants, Marshall and Belews Creek, correct?

A Well, I believe in both of them it was 1989.

Q Okay. So late 1980s, not mid 1980s, correct?

A Right. And then the monitoring that was done was for a landfill, but it was in some cases the groundwater wells were put adjacent or very near the coal ash plant. They weren't specifically, as I understand it, intended to be monitoring points for the coal ash basins.

Q But you actually used the data from -- from those wells in connection with your evaluation of groundwater -- groundwater "contamination," your definition of contamination, at those plants from the ash basins, correct?

A Well, sure. If you're going to put a well next to the ash basin, even though it was intended to monitor landfill, it doesn't mean you ignore the data because it was put next to the ash basin.

Q So my question to you is, there was groundwater monitoring in the mid-to-late 1980s at both Marshall and Belews Creek as part of the -- of an NPDES permit program, correct?

A Correct. Late -- 1989 is when I show the earliest groundwater monitoring.

Q Okay. And there was further groundwater monitoring at Dan River and the W.S. Lee plants beginning in the early 1990s as part of an NPDES permit program with respect to those plants, correct?

A Correct, 1993, yes, at both of them.

Q And that monitoring program was, in fact, with respect to the ash basins at those plants, correct?

A That's correct. That's my understanding, yes.

Q And then we talked already about the groundwater monitoring that took place as part of the USWAG voluntary monitoring program, correct?

A That's correct. I mean, we touched on it briefly, yes.

Q And that -- that involved essentially all of the Duke Energy Carolinas plants, starting with Allen in around 2004 and going forward with a number of the other plants until the late 2000s, correct?

A That's correct.

Q And Mr. -- Mr. Hart, do you have any information that suggests to you that these monitoring wells, all of them that we've just been talking about, apart from the Allen early time period, were all done in connection with either the USWAG study or NPDES permits, that the location and number of wells, the depths of the wells, the sampling frequency and the sampling parameters were not established in conjunction with whichever environmental regulatory agency, DEQ or DHEC, was in charge of those programs?

A Well, I think to the extent that they were associated with a permit, for example, at Dan River or W.S. Lee, I do believe that they were most likely installed in conjunction with the DEQ's input and the parameters were agreed upon. Now, with regard to the other facility where it was part of USWAG, other than the Allen plant, I don't see any indication that they were -- those wells were installed in conjunction with some input from DEQ. In fact, DEQ, when the data was submitted, had a number of comments about the well location. Some of them, they said, were not appropriate for background determination, things like that. And they also said, at that time, we need to increase the parameter list to come up with a larger set of parameters for things like boron and vanadium that weren't analyzed for in USWAG.

Q Well, they had comments about the well placement for the Allen plant, too, didn't they, when they -- in the latter part of the 2000s?

A They -- I don't know. I'd have to -- I'd have to look. But I see no indication that they installed those wells as part of USWAG, other than at the Allen plant, as part of some discussions with DEQ. But if you have some, you know, documentation to that effect, I'd be glad to look at it.

Q Well, let's -- let's move just slightly, Mr. Hart. You mentioned that at least with respect to the permitted wells that are part of an NPDES permit program, the relevant environmental agency would have had some input into and direction to the permitee, in this case Duke Energy Carolinas, about well placement and parameters -- frequency of sampling and the parameters of the sampling, correct?

A Typically, yes, although I haven't seen any documentation. But, yes, typically that would be the case.

Q And these NPDES permits are regularly renewed, correct?

A Yes. They are usually on a renewal cycle. That's correct.

Q And in each of the renewal processes, the relevant environmental regulator can adjust its requirements relating to sampling frequency and sampling parameters, and often does, correct?

A In some cases, yes, they can. Uh-huh, yes.

Q And Mr. Hart, with all of this monitoring going on over the time frame that stretches back to 1989, DEC reported to the DEQ the sampling results every single time, as required by its permits, correct?

A I don't know that. We did FOIA requests for these facilities, but in most cases they did not have the data or weren't able to find the actual submittal, so I don't know that for a fact.

Q Look, if you would, Mr. Hart, at DEC Exhibit 20.

A Okay.

MR. MEHTA: Chair Mitchell, I would ask that this document, DEC Exhibit 20, be marked for identification as Hart DEC Cross Examination Exhibit 3.

CHAIR MITCHELL: All right, Mr. Mehta. Just keeping with the convention we've established for your previous exhibits, we will mark this document as DEC Hart Cross Examination Exhibit 3.

MR. MEHTA: Thank you, Chair Mitchell.

(Whereupon, DEC Hart Cross Examination Number 3 was marked for identification.)

Q And Mr. Hart, what this document is, is what's commonly referred to in the last proceeding and presumably will be referred to in this proceeding, as the Sutton Settlement. Do you understand that?

A Yes, but -- yeah. So, yes, if that's what you want to call it, that's fine.

Q Well, you can -- you can check me in the voluminous record from the last proceeding, but we called it the Sutton Settlement.

A Totally fine. I understand.

Q And if you look at the bottom of page 2, there's a whereas clause that says, "Whereas, the National Pollutant Discharge Elimination System (NPDES) permits associated with the Duke Energy sites contain requirements for Duke Energy to monitor groundwater at the Duke Energy sites and report the results to DEQ," correct?

A Yes. It's not really talking about what time period. A lot of them didn't have groundwater monitoring requirements in them until barely like post-Dan River, I would say. This is 2015, so I think it was mostly post-Dan River. So the only one, I think, that proceeded this, and I could be wrong, is Dan River itself.

Q Well --

A And it had something in it -- a requirement in the NPDES permit that required groundwater monitoring.

Q Okay. So Dan River clearly had that because they had the permit requirements from the early 1990s, correct?

A Correct.

Q And Marshall and Belews Creek clearly had that because they were -- there were wells installed as part of an NPDES permit program in, I think you said, 1989, correct?

A Well, that wasn't for the NPDES permit. Those were for landfill, solid waste permits --

Q Well, but then --

A -- at those two facilities. Those weren't NPDES permits --

Q In any event --

A -- where they are required.

Q In any event, Mr. Hart, do you have any information whatsoever that suggests to you that Duke Energy Carolinas did not provide to the DEQ every single result from its groundwater monitoring programs at any of its plants to the DEQ?

A Well, for example, I haven't seen data from 1984 or 1978 or '79 at the Allen plant that it was submitted to DEQ. Now, to the extent it was part of some NPDES permit, I don't have anything to disagree with that, other than to say that for the most part, other than Dan River, the facilities didn't have groundwater monitoring requirements in them until, I believe, 2014 or

'15 after Dan River --
Q In any event --
A -- after the spill.
Q But Mr. -- Mr. Hart, if you'd just look at the next page of the Settlement Agreement, the top of page 3, the whereas clause says that Duke Energy has complied with its groundwater monitoring and reporting requirements with respect to the Duke Energy sites, correct?
A That's what it says.
Q Okay.
A But what I'm getting at is -- what you're trying to imply, I think, is that there's this long history from 1989 and 1993, all the way to 2015, of Duke submitting groundwater data required under its NPDES permits. That's not correct. They only had groundwater monitoring requirements for their coal ash basins for NPDES permits starting, I believe, in 2014 and '15 at some facilities, but what -- so there's not this voluminous data that DEQ had in 2015 at these facilities. They had some data from the USWAG, but they didn't have a bunch of data from the NPDES permits.
Q Mr. Hart, do you have any information that suggests to you that Duke Energy Carolinas did not submit

to the DEQ all of the groundwater monitoring information generated as a result of this USWAG voluntary groundwater monitoring program?

A I don't have any information to that effect, but I haven't looked at -- well, again, we did FOIA requests at DEQ for these facilities. There are some data submittals, but I don't know if they're every single one, but there are some that were submitted to DEQ, yes.

Q Well, Mr. Hart, let's talk, then, about what you did or what you looked at in conjunction with your investigation of this matter. And I think the -- if you look at pages 6 and 7 of your prefiled testimony, you outline what you looked at, right?

A Yes, I did.

Q So you reviewed the coal ash related testimony in this case, correct?

A I'm not sure I understand what you mean.

Q Let me -- maybe that was a bad question. I'll try it again. I'm looking at lines 6 and 7 on page 6.

A Right. Yes. I --

Q And you say --

A Go ahead.

Q You say there, "I reviewed the parts of DEC's 2019 rate case application and testimony relating to coal ash," right?

A Correct.

Q And the next --

A To the extent that I knew it was coal ash related. Now, there's a lot of documents in there and not every one is listed as coal ash, but if they had some indication of coal ash or, for example, Ms. Bednarcik's testimony, I did review it.

Q Okay. And you also indicated that you were provided access to the Merrill data site, which is a document portal for documents produced in connection with this case, correct?

A Well, I had access to it and I did some queries. Now, that's a very -- it is not a -- it's a pretty user friendly document portal, but I did do some queries and was able to get some documents.

Q And you also indicate in the third bullet that you were provided access to the Concilio/Relativity online database and performed queries and reviewed various documents in -- in that portal, which as I understand it, houses millions of documents that have been produced by Duke Energy over the course of years in connection with any number of legal proceedings, correct?

A That's my understanding, yes, but, again, no way to review every document on there. I did some queries, to the extent I could, and -- and was able to find some documents.

Q So I guess, Mr. Hart, you would actually be the first to admit that you did not review every single document in that database to assess its impact on the question of whether Duke Energy Carolinas was, you know, proactive enough with the -- with its environmental regulators, did you?

A I don't know that anyone could review every single document in that database in the time frame of -- of which I did my work.

Q I --

A I would think it humanly impossible.

Q Understood, and I would agree with you. You did not actually talk to anybody at DEQ to investigate its view of whether DEC was being proactive enough, did you?

A No. I think, as I mentioned in the deposition, we did try to reach out to some of the folks at DEQ, but because of the ongoing litigation between DEQ and DEC, they were very hesitant either to provide documents or discuss items.

Q Well, your client in this proceeding is the

Attorney General's Office, correct?
A Correct.
Q And the Attorney General's Office is an agency of the State of North Carolina, correct?
A Correct.
Q And the DEQ is an agency of the State of North Carolina, correct?
A That's correct.
Q And when the DEQ needs legal advice or representation, it looks to the Attorney General's Office to provide it, doesn't it?
A I believe so, yes. Sometimes it seeks outside counsel as well.
Q So, Mr. Hart, I'm curious. If you wanted to find out from the DEQ what -- its view of the proactive nature of DEC's actions regarding groundwater monitoring, why didn't you just ask your client, the Attorney General's Office, to get in contact with the DEQ and set up interviews with present or former DEQ officials who could answer your questions?
A Well, I think the documents speak for themselves for the most part.
Q So you don't think --
A It's very clear that DEC submitted the USWAG

data to DEQ without any explanation. They implied that the data was consistent with background, which it clearly was not. And, you know, it wasn't until DEQ started looking at the data in 2009 and '10 that they said, look, we think there's -- you need to provide us more information here. Those are -- those are written in the -- in the letters from DEQ to DEC. You've been providing this data. We don't know whether wells are -- we see 2L standard violations. We need more information.

Q So, Mr. Hart, you don't think it's necessary to obtain the DEQ's views directly from somebody at DEQ in order to assure yourself that your investigation was fair and that the conclusions you reached were supported by a complete review of the evidence? Is that what I'm hearing?

A No. I think I did do a complete review of the evidence, you know, and my experience. I mean, I know how groundwater has been addressed and how people deal with groundwater in North Carolina. I've been dealing with it for 30 years, including the 2L regulations. I don't have to talk to a regulator to tell me whether DEC -- what their opinion was of DEC. The -- the rules are very clear as to how you address them. And, in fact, the USWAG policy was -- or the action plan was very clear, and this is why they went to DEQ and EPA and said, if we have groundwater standard exceedances, then we're going to address them and come up with an action plan to deal with them. We're going to come up with a corrective action plan to deal with them, and that didn't happen.

Q Turn, if you would, Mr. Hart, to DEC Exhibit 40.

CHAIR MITCHELL: All right, Mr. Mehta. Before you begin this next line, we're going to take a morning break. We're going to go off the record now. We'll go back on at five after 11:00. During this break I'd ask that you all please work out order of witnesses, in light of our discussion on the CIGFUR motion at the beginning of the hearing this morning. All right. We'll be back on at 11:05. Please turn off your cameras and your microphones.

(Recess taken from 10:47 a.m. to 11:14 a.m.)

CHAIR MITCHELL: All right. Let’s go back on the record, please.

THE WITNESS: Can you all hear me?

CHAIR MITCHELL: All right. I’d like to address the pending Motion to Strike raised first by counsel for CIGFUR III. I am going to deny the motion and allow the testimony of Mr. Floyd to stand. I’m going to deny the Request for Leave to file rebuttal that counsel for CIGFUR III made as well. I am going to allow CIGFUR to put up its witness following the presentation of the -- I believe it’s the McLawhorn/Floyd Panel.

And with that, any additional matters for me to consider before we get back into the cross examination of AGO witness Hart?

MR. PAGE:: Madam Chair, this is -- go ahead, Camal.

MR. ROBINSON: Yeah. Sure. Hi, Chair Mitchell. I just wanted to at least report back. So we did have a call with some of the parties on break, not every party was on the phone, and through the discussion, just to notify you, the parties have generally agreed that Mr. Phillips could be the last cross examination -- could be the last attorney -- excuse me -- the last witness to testify after the Public Staff. So just wanted to flag that for you, and that we defer to Ms. Cress and Ms. Downey and Mr. Neal for anything further.

CHAIR MITCHELL: All right.

MS. DOWNEY: Chair Mitchell?

CHAIR MITCHELL: I believe that’s Ms. Downey.

MS. DOWNEY: Yes. Yes, Chair Mitchell. In light of that, the Public Staff would like to reserve cross time. We had not done so up to this point.

CHAIR MITCHELL: You -- reserve cross time for CIGFUR witness Phillips?

MS. DOWNEY: Yes, Chair Mitchell.

CHAIR MITCHELL: Okay. Understood.

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

CHAIR MITCHELL: You may proceed, Mr. Neal.

MR. NEAL: NC Justice Center, et al. would also ask to reserve cross time following additional testimony from Mr. Phillips.

MS. CRESS: And Chair Mitchell, this is Christina Cress with CIGFUR. That's consistent with what the parties discussed on the call, and CIGFUR is in agreement -- not in agreement, but, rather, we consent.

CHAIR MITCHELL: Okay. So Mr. Phillips will be presented following, just for purposes of the record and so that we're clear here, following the presentation of the Public Staff's witnesses. By my notes, that indicate -- the final Public Staff witness is Boswell, so following Boswell. And I have that both the Public Staff and North Carolina Justice Center, et al. have reserved cross examination for the witness.

MR. PAGE: Chair Mitchell?

CHAIR MITCHELL: Any other parties to --

MR. PAGE: Chair Mitchell, this is Bob Page.

CHAIR MITCHELL: Mr. Page, I'll get to you in one second. Let's wrap up on this CIFGUR witness Phillips issue. Any additional parties reserving cross examination for the witness?

(No response.)

CHAIR MITCHELL: All right. Hearing none, Mr. Page, you may proceed.

MR. PAGE: Thank you, Chair Mitchell. I wanted to advise you of a situation and perhaps follow that up with a motion. My witness, Mr. O'Donnell, has a conflict with appearance at the Maryland Commission, and he's been juggling these two events for the last two weeks. He's already put them off twice in anticipation of getting on, and it just hasn't worked that way. I think that the book that the rabbi wrote about bad things happening to good people pretty well explains where we are. But if I can get him on, and I don't know how much longer Mr. Mehta has with the Attorney General's witness, or how many questions the Commission may have, if I can get Mr. O'Donnell on this morning before the lunch recess, then he's able to continue this afternoon until he's finished, but if I can't do that, then it will be tomorrow afternoon before he's available again. So in that circumstance, I would move to take him out of the rotation following Mr. Hart and put him back in sometime during or after the Public Staff's testimony.

CHAIR MITCHELL: All right. Mr. Page, is this a matter that was discussed with the parties during the break?

MR. PAGE: I was not in on that conversation. Nobody called me.

CHAIR MITCHELL: All right. Does any party object to -- counsel for any party object to reorganizing or rearranging order of the witnesses at this point to accommodate Mr. Page's request?

(No response.)

MR. PAGE: That would mean, in essence, that we would go from Mr. Hart down to Mr. Ryan on the witness list.

CHAIR MITCHELL: Any objection from any party, counsel for any party?

(No response.)

CHAIR MITCHELL: All right. Hearing none, Mr. Page, I'm going to allow you to call your witness tomorrow afternoon whenever he may be available.

MR. PAGE: Thank you, Madam Chair, and I will advise you when I know that he will be.

CHAIR MITCHELL: All right. Mr. Mehta --
MR. JENKINS: Madam Chair?
CHAIR MITCHELL: -- we'll proceed with you.
MR. JENKINS: Madam Chair, Alan Jenkins.
CHAIR MITCHELL: Mr. Jenkins?
MR. JENKINS: May I proceed?
CHAIR MITCHELL: You may.
MR. JENKINS: Thank you. Commercial Group was also not called on that matter, and is the intent to move the two Staff witnesses Floyd -- the Floyd Panel further down the list, because I believe Duke still has a right to rebut -- file rebuttal testimony of that. And it seems -- it seems it would be more appropriate to have them go later than earlier.
CHAIR MITCHELL: Mr. Jenkins, I do not understand your question. Would you please ask your question again?
MR. JENKINS: Sure. Right now the Floyd Panel for Staff is fairly early in the Staff order, and I believe Duke has the right to file rebuttal testimony to the Floyd testimony that was just filed and that the Motion to Strike was not granted. So it seems more appropriate to have the Floyd Panel move further down at least among Staff and perhaps later on in the

proceedings, just have rate design witnesses, rather than having them so far in advance and in advance of Duke's rebuttal testimony.

CHAIR MITCHELL: All right. Mr. Jenkins, at this point in time the decision has been made to allow CIGFUR witness Phillips to be presented for examination purposes following the final Public Staff witness, so that's where things stand procedurally at this point in time. All right. Anything further?

(No response.)

CHAIR MITCHELL: All right. Mr. Mehta, we are with you and Mr. Hart. Please proceed.

MR. MEHTA: Thank you, Chair Mitchell. And Mr. Hart, your video just went out. There we are.

THE WITNESS: Sorry. Hit the wrong button.

MR. MEHTA: Yeah. I do that all the time. Sign of advancing age, I'm afraid, Mr. Hart.

THE WITNESS: If I could, I just want to correct something I said earlier on the NPDES permits and groundwater monitoring. The NPDES permits -- I went back and looked at some of the permits -- started requiring groundwater monitoring at some facilities around the 2011 to 2013 time period after the USWAG data had been submitted, not after the Dan River spill. So that's --

my apologies. I just wanted to correct that on record to be accurate.

MR. MEHTA: Okay. Thank you, Mr. Hart.

Q And actually on that subject, if you would take a look at your deposition which we marked as Exhibit 1, Cross Exhibit 1.

A My deposition. Okay. Yes.

Q And page 79 of your deposition.

A Okay.

Q And the subject matter on this page is the submission of data by Duke Energy Carolinas to the DEQ, correct?

A Yes. Generally, yes.

Q Okay. And you indicate at line 15 -- starting at line 15 that the earliest date of submittals that you've seen or you had seen was from the 2009 time frame, correct?

A Yes. That's correct.

Q And on line 17 you said "I tried to get more historical data," correct?

A Correct.

Q But you could not locate more historical data, correct?

A Yes. We did a FOIA request and did, in fact, get the Attorney General’s Office involved, and DEQ sent us what was in their electronic files. This was during the COVID -- well, we’re still ongoing, but the beginnings of the COVID issues, and so they had no one in the office that was willing to go to the office and look for the files.

Q And you further indicate that while you tried to locate it, you couldn’t, and you "don’t have any evidence that they did,” meaning that Duke Energy Carolinas did submit such data; is that correct? That’s lines 19 and 20.

A Right. So not saying that they didn’t submit it, but I don’t have evidence that they did.

Q And then I asked you on line 21 “Do you have any evidence that they did not,” and your answer on line 22 was “No,” correct?

A Correct. Yes.

Q And I asked you at line 23 “Do you have any reason to believe that they did not,” and your answer at line 25 and carrying on to the next page was “I don’t have any reason to believe that they did not send in the data, no.” Is that correct?

A That’s correct, yes.

Q Now, Mr. Hart, look, if you would, at DEC

Exhibit 40.

A Okay.

MR. MEHTA: And Chair Mitchell, I'd like to go ahead and mark this document as -- let me get my sequence straight. I guess this would be DEC Hart Cross Examination Exhibit 4.

CHAIR MITCHELL: All right. The document will be so marked.

(Whereupon, DEC Hart Cross Examination Exhibit Number 4 was marked for identification.)

Q And Mr. Hart, this is a deposition of Coleen Sullins taken in what we've come to call the Sutton OAH proceeding, correct?

A It says Duke Energy Progress vs. North Carolina Department of Environment and Natural Resources, Division of Water Resources, is with the -- well, in the Office of Administrative Hearings.

Q Okay. And it's an OAH, Office of Administrative Hearings, proceeding, and would you take, subject to check, that it involves the OAH's or -- excuse me -- DEQ's imposition of a fairly sizable monetary penalty in connection with the operation of the Sutton plant?

A That’s my understanding, yes.

Q Thank you. And Mr. Hart, if you would look at pages 9 and 10 of the deposition, Ms. Sullins notes there that while at the time of the deposition she was no longer with DEQ, her last full-time position there was the Director of the Division of Water Quality, correct?

A I’m sorry. What lines are you on?

Q Let’s see. Page 9 -- page 9 at the very bottom of the page she’s asked “What’s your current employment status,” and she -- and the answer is “I’m unemployed,” correct?

A Yes. That’s what she says. Right. Yes.

Q And if you go on to page 10, the question is “What was your last full-time employment?” The answer is “Director of the Division of Water Quality,” correct?

A Yes. That’s what it says. Yes.

Q And line 7, the question is “When did you leave that employment?” The answer is “December of 2011," correct?

A Correct.

Q And Mr. Hart, just to level set us, the questions being posed to Mr. -- to Ms. Sullins, if you go up to probably page -- very early -- page 2, the questions are being posed by Mr. Wheeler, correct?

Excuse me. Page 6, line 3.

A Six, line 3. Yes, by Mr. Wheeler. I see that. Yes.

Q And if you go -- maybe this is what's on page 2. Yes. Appearances for the Respondent, which is the DEQ, Mr. Wheeler is the lawyer for the DEQ, correct?

A Yes. That's my understanding, yes.

Q Okay. And if you go back to page 10 where Ms. Sullins says that her last full-time employment was as Director of the Division of Water Quality, the Division of Water Quality is a division within the DEQ, is it not?

A That's correct.

Q And it is the division at DEQ that is responsible for groundwater and surface water regulation, correct?

A Well, I mean, there are other divisions. Division of Waste Management also is involved in groundwater rules and groundwater conditions, but they are the ones responsible for, for example, the coal ash basins and for rules that are associated with surface water regulation.

Q The Division of Water Quality is or the Division of Solid Waste Management?

A The Division of Water Quality, which is now the

Division of Water Resources.

Q Okay. And the Division of Water Quality is the Division or whatever its name is now, but certainly it’s the division responsible for, for example, enforcement of the 2L rules, right?

A Well, it could be. I mean, there certainly are other divisions that also enforce the 2L rules. I mean, you could have a Superfund site or a site under RCRA regulation or inactive hazardous sites that also, if they had a groundwater standards violation, could also issue some sort of Notice of Violation or regulatory requirement with regard to 2L.

Q But the Division of Water Quality is an agency that is involved in the enforcement of the 2L rules, correct?

A That’s correct.

Q Now, Mr. Hart, if you look at the very bottom of page 21 of Ms. Sullins’ testimony -- are you there?

A Yes, I am.

Q The question posed by the lawyer for the DEQ on line 25 is “Let’s focus in on the coal ash issue.” And moving on to page 22, the top of page 22, he asks if Ms. Sullins could tell him when the issue of coal ash first sort of came on her radar, correct?

A Correct.

Q And he indicates that he -- what he really wants in lines 5 and 6 is when it came on her radar any time during her tenure at DEQ, correct?

A Yes.

Q And on line 7 she answers that it came on her -- on her radar when she was a permit supervisor over the NPDES permitting programs, correct?

A Correct.

Q And if you look back at page 13 of her deposition, Mr. Hart, she indicates that she became the permit supervisor back in 1992, correct?

A Well, she was dealing with stormwater until 1992 and then -- oh, yeah, supervisor for the NPDES program, yes.

Q So --

A Sometime after 1992, I guess.

Q All right. If you flip back, then, to page 22 -- just tell me when you're there.

A Okay.

Q And on line 10 she says "Coal ash has been an issue that I dealt with for most of my career at the Division of Water Quality," does she not?

A Yes.

Q And if you go forward, Mr. Hart, to page 26, the bottom of page 26 --

A Okay.

Q -- and it's really the question that begins on page 25 and then carries over to -- excuse me -- line 25 and then carries over to page 27, the lawyer for the DEQ asks Ms. Sullins what the first time you -- she remembered groundwater issue coming up after she began her supervisory work over aquifer issues, correct?

A I'm sorry. Where is that? What line?

Q I'm sort of paraphrasing, but just tell if I'm paraphrasing incorrectly. Page 26, line 25, then the question carries over to page 27, lines 1 through 3.

A Okay. Yeah.

Q And just to level set us on the timing, then, Mr. Hart, if you go back to page 15 of her deposition, lines 12 through 19 -- just tell me when you're there --

A Okay. Yeah. I'm there.

Q Ms. Sullins indicates that she first gained supervisory control over aquifer protection when she became the Deputy Director of the Division of Water Quality which was in 2004, correct?

A Correct, yes.

Q And then if you, again, flip forward, Mr. Hart, to page 27 of Ms. Sullins' deposition --

A Okay.

Q -- lines 4 through 7, after the lawyer for the DEQ asked her when -- the first time she remembers the groundwater issue coming up after she became in a supervisory role was in the wake of the TVA dam collapse, correct?

A Correct.

Q And the TVA dam collapse took place in 2008, if my memory serves. Does that sound right to you?

A Yes. She's saying -- yes, 2008, she's saying is when we -- when we started looking at coal ash more holistically in the state.

Q Okay. And then if you move forward, Mr. Hart, to page 29 of her deposition.

A Okay.

Q Starting at line 2, the lawyer for the DEQ asks Ms. Sullins if it was her understanding that until the Tennessee Valley spill, there had not been any other activity on that subject. Do you see that?

A Yes.

Q And if you just go up a page to page 28, lines 24 and 25, that subject that the lawyer for the DEQ is talking about is groundwater monitoring, correct?

A Yes. About in the previous decade there was discussion about the possibility of groundwater monitoring.

Q And on page 29, in answer to the question if it was Ms. Sullins' understanding that until the TVA spill there had not been any other activity on that subject, groundwater monitoring, Ms. Sullin -- Ms. Sullins answers, line 5, "No. That's not my understanding," correct?

A Right. And then she qualifies it by saying "I don't know the details about the groundwater monitoring."

Q That's correct. But at line 7 she says that discussions had been held between the utility companies and the Aquifer Protection staff about getting wells installed and beginning some initial evaluation, correct?

A Well, she says "I don't know the discussions that had been held," not -- I read that as I don't -- you can read that two ways. One is whether they had been held, or one is she doesn't know whether they had been held, but that's what it says.

Q Well, immediately before that she says "I don't know the details," and then says "I don't know the discussions that had been held."

A Right.

Q That would suggest that there were discussions that had been held of which she does not know the details; isn't that correct, Mr. Hart?

A Again, I think you could read it both ways. I think you could say I don't know about any discussions that had been held, or there were discussions and I don't know the details. She doesn't say there were discussions, I know there were discussions between utility companies and the aquifer protection staff, but I don't know the details. That's not what she said. I think you could read it both ways.

Q Okay. Well, in line 11, she says "Some of that had been done," correct?

A Yeah. I don't know what the "some" is. Is that meetings or well installation?

Q Well, in line 14, the lawyer for the DEQ asked Ms. Sullins "So this wasn't a blank slate when the Tennessee Valley spill happened; is that correct?" Do you see that?

A Correct.

Q And her answer is "Absolutely not." Do you see that?

A Right. And by that time I would agree. They had data from the USWAG monitoring that had been submitted, but not really reviewed, until 2009 or ’10, which is within her time of looking at it -- within her time of being division director.

Q And if you go on to page 30 of her deposition, Mr. Hart, you will see at lines 15 -- beginning at line 15, Ms. Sullins says “The power companies, we were constantly in interaction with them because we were issuing permits for them to do a variety of different things.” Do you see that?

A Yes.

Q And she goes on to -- she goes on to say at line 19, “So, you know, they,” meaning power companies, “were sort of always on the radar like a large -- a large permitted entity would be, and a complex permitted entity because it involved multiple divisions trying to figure out how to issue the various permits for which they had responsibility and deal with the various issues,” correct?

A That’s what it says, yes.

Q And the “they” is the power companies, correct?

A Yes. They were -- yes. Both divisions were involved, Air Quality, Water Quality, yes, permits, with regard to permits, as I read this.

Q And the deposition goes on, on page 31, to identify the power companies as what we now know today as Duke Energy Carolinas and Duke Energy Progress, correct?

A Yes. The primary ones that we're dealing with.

Q Now, Mr. Hart, if you would go back to your prefiled testimony.

A But like I say, this also, this testimony that you pointed out, there's a question that says "Were you aware that Mr. Tom Reeder has taken the position in this case on behalf of DENR that you," meaning Ms. Sullins, "among other former employees -- DENR employees 'didn't do a damn thing with regard to the coal ash'"?

Q And she said "I'm aware of that, but I disagree."

A No. She said "No, I wasn't aware of that."

Q Okay.

A She didn't say I didn't disagree.

Q Well, she --

A We're not -- all I'm saying is Ms. Sullins may not be the best person about whether DEP or DEC was doing something, because apparently DENR is taking the position that she didn't do a damn thing about coal ash. And she says even here "I don't recall specifics. I wasn't involved in most of the meetings with Duke and Progress."

Q But you never talked to her or Mr. Reeder, did you?

A No. I have her deposition.

Q Well, you have it now.

A Yes.

Q You didn't have it when you did your prefiled testimony, did you?

A No. I don't -- I mean, I usually don't talk to regulators when I do these kind of things, but it's not that important to me. What's important to me is whether they complied with the rules, and they didn't comply with the 2L rules. This is saying we were -- they were on our radar for permits. You don't get a permit to contaminate groundwater, right? You can have a permit to do something, but those permits don't give you the ability to contaminate groundwater. So if you contaminate groundwater, you have to address it. You have to do corrective action and you have to eliminate the source and those kind of things.

Q Mr. Hart, if you would look at page 8 of your testimony.

A Testimony -- okay.

Q And I think we went over this earlier, but your first conclusion that you summarize there says that DEC -- the utility industry and DEC knew about the potential for contamination of groundwater from coal ash as early as the 1980s, right?

A Yes.

Q And I think we had a discussion about what you meant by the word “contamination.”

A Correct.

Q We don’t need to revisit that. What do you mean by the word “potential”?

A Well, that there was some reasonable potential that coal ash basins could lead to groundwater contamination. It wasn’t some hypothetical. It wasn’t something that only happened in a few places. There was a reasonable potential that if you had a coal ash basin, you could have groundwater contamination. It wasn’t an absolute, but it was reasonable potential, probably more likely than not, maybe not back in the ‘80s, but certainly there was the potential that something could happen.

Q And Mr. Hart, the -- if I’m understanding your testimony correctly, up through probably the middle part of the first decade of the 2000s, the exceedances of the 2L standards experienced at Duke Energy Carolinas' power plants, whether or not they're at the compliance boundary or not, just exceedances --

A I'm sorry. You cut out for a second. I didn't hear you.

Q Sorry. If I understand -- if I read your testimony, prefiled, correctly, up until the sort of middle of the first decade of the 2000s, maybe a little bit towards the latter part of the middle, the exceedances of the 2L standards experienced at power plants, no matter where -- I mean, whether it's a compliance boundary or not compliance boundary -- were primarily of iron and manganese, correct?

A I think most of them were, but certainly not all of them.

Q Most of them were?

A Most of them were iron and manganese.

Q And iron and manganese are ubiquitous in Piedmont soils, correct?

A Yes, they are.

Q And every single one of the -- of DEC's power plants was built in the Piedmont soils area, correct?

A Yes. The DEC plants, yes.

Q And neither iron nor manganese is a hazardous substance, is it?

A I don't know. I'd have to check. I don't believe iron and manganese -- some forms of manganese could be. Some forms of iron could be. Ferric chloride or something could be a hazardous substance. I'm not sure.

Q So is it your testimony that the -- I mean, the EPA has lists of hazardous substances. Do you believe iron and manganese are on that list?

A Well, iron and manganese rarely occur just by themselves as hazardous substances. And they're usually complex with something, so they're not usually -- a ferric oxide would be iron and oxygen and ferric chloride, and so I don't know if some of those complexes might be in there, so iron usually doesn't disassociate itself and just appear as disassociated metal in the environment.

And one of the reasons you find high levels of manganese and iron around coal ash plants is because they create a low oxygen environment, and when you do that, you liberate naturally occurring iron and manganese in the environment. So when you see concentrations, you know, if you have concentrations that are near the standard or slightly above, then you could say that's background, but if you've 10,000 parts per billion of iron or manganese in groundwater, that can't be background. It's not possible without some -- in the

Piedmont without some intervening contamination or some non-natural issue.

Q And Mr. Hart, just make sure I understand. There is a 2L standard for both iron and manganese, correct?

A Correct.

Q And that 2L standard is the same as the drinking water standard, correct?

A What drinking water standard are you talking about?

Q Well, I guess the EPA publishes drinking water standards, does it not?

A Correct.

Q And they're called MCLs, but help me with the -- what the M and the C and the L stand for.

A Maximum contaminant levels.

Q Okay. And there are primary standards and secondary standards, correct?

A For EPA and the drinking water rules, but there are -- there's no analogous in the analog to the 2L standard. There's no primary or secondary standards in the 2L rules.

Q I understand, but I'm talking about the drinking water standards at this point.

A Okay.

Q And the primary standards, as I understand it at least at the very high level that I might understand or not understand, are essentially health related issues or could -- exceedance of those standards could cause some kind of a health related issue, correct?

A Yes. Generally, you can say that, yes.

Q And the secondary standards -- exceedance of the secondary standards is related to essentially aesthetic issues, taste, smell, things of that nature?

A Generally, yes, but you could have a case where there's a secondary standard and it's -- it still has a health effect, but because the taste or odor threshold is lower than, for example, health based effect and they base it upon the aesthetic effects.

Q But in terms of iron and manganese, they're both -- the standards are both secondary MCL standards, correct?

A For drinking water, not for North Carolina groundwater, yes.

Q But the drinking water standard is the same standard as the 2L standard for groundwater in North Carolina, correct?

A That's correct.

Q So Mr. Hart, when you came to the conclusion that Duke Energy Carolinas was not proactive enough in dealing with the DEQ, did you eliminate the possibility that DEQ saw the exceedance of the 2L standards, understood that the exceedances posed no threat to the health of anyone, and decided they had other fish to fry?

A Well, I don't have any reason not to believe that, other than in 2009, DEQ sends that letter to DEC and says we've been getting this data. It's showing us exceedances of the 2L standards. We need to understand where the wells are at your facilities. All we've gotten is just data, right? I don't -- we don't -- we need to understand background. We need to understand the compliance boundary. We need to understand the waste boundary. So at least in 2009 they weren't just -- decided that they had other things to do.

Now, that's certainly the case. DEQ often is overworked and they have limited staff, so that's happened, but that doesn't mean that you can ignore the rules. Just because somebody doesn't issue a Notice of Violation, a Notice of Regulatory Requirement, doesn't mean it's not a violation and it has to be addressed in accordance with the rule.

Q I understand, Mr. Hart. And if you would look at your Exhibit 11.

A My Exhibit 11. Okay.

Q Actually, I think I need another exhibit, but the -- I think we could probably do it this way. The first paragraph of this exhibit, which is a letter to Mr. Allen Stowe from DEQ, indicates that the DE--- that the DWQ, Division of Water Quality, has been reviewing the data and map submitted by Duke Energy on April 30th. Do you see that?

A Yes. Right. In response to their request earlier to provide the map, yes, and a summary of the data.

Q Right.

A There was a letter that preceded this one that --

Q Yeah --

A -- said all we’ve been getting is data; we need maps, we need summary tables, I believe.

Q And without agreeing with your characterization of that letter since we don’t have the letter right in front of us, Mr. Hart, but that’s the letter I was trying to locate in which the DEQ asked for additional information concerning the location of wells, et cetera, correct?

A Right.

Q And if my memory -- my memory of that is it's sometime in March of 2009, correct?

A I believe that's correct, yes.

Q And whatever information that the DEQ asked for was, in fact, submitted to the DEQ, at least according to your Exhibit 11, on April 30th, 2009, correct?

A Well, I think -- I don't think so because I believe that letter also said -- the original letter said to the extent that you have 2L violations, you need to tell us how you're going to address them.

Q Well --

A And I didn't see that was provided in this letter.

Q Okay. And then in the -- in the letter dated December 18th, which is your Exhibit 11, the DEQ addresses that issue and says since you submitted all that data, we, the DEQ, have been consulting with our lawyer, the Attorney General's Office, to figure out whether we actually can ask you to do what we're asking you to do, correct?

A No.

Q In terms of placing wells at the compliance boundary, et cetera.

A No. What this is saying is whether DEC can use the provisions 2L.0106, which are the corrective actions rules which allow natural attenuation, so it doesn't say -- it just says do we have to do -- is DEC allowed to do natural attenuation under rules that had been promulgated not, I believe pretty -- like 2008 or so that allowed companies to seek or regulated people to seek what they call alternate remediation, which can be by natural attenuation or not cleaning up -- or getting a variance and things like that.

Q Okay. In any event, Mr. Hart, let's just go back to your prefiled testimony concerning the potential for groundwater contamination known to the industry and DEC from the 1980s.

A Okay.

Q I was looking, Mr. Hart, through the authorities that you cite in your testimony, and there appear to be three from the 1980s, correct? The first one is the 1980 EPA TVA Report which is Joint Exhibit 5. It's referenced in your testimony --

A Yes.

Q -- on pages 50 to 51.

A Right. I have to -- I'd have to check and see which roll over from the '80s.

Q And the second one that I found is the 1988 EPA Report to Congress which is Joint Exhibit 13. It’s referenced at your testimony at page 51 and 52. And the third one that I found was your reference to the 1984 Investigation at the Allen plant, which is Joint Exhibit 9, at your testimony pages 57 and 58. If I missed one, just let me know.

A Let me look. You have the March ’80 EPA Effects of Coal Ash Leachate on Groundwater; 1988 EPA Report to Congress; and then the Duke Coal Ash Disposal Report from 1984. Those are the ones that you have?

Q Yes.

A I believe that’s correct, yes.

Q Okay. So these are your sources for the conclusion that as early as the 1980s, the industry and DEC knew of the potential for groundwater contamination, correct?

A Well, they’re some of the sources. I did not attach everything I reviewed as an exhibit. So I believe I did provide some other documents in response to DEC’s request for my files that aren’t necessarily attached as exhibits to my testimony, so I believe there are some others from the 1980s as well.

Q Well, not to belabor it, Mr. Hart, but these are the ones that you actually referred to in your testimony?

A That's right. That's correct.

Q And, again, all of this is in the context of your definition of the word "potential" and your definition of the word "contamination," correct?

A Yes. I would say it's supportive of the testimony summary 1 about the potential for groundwater contamination as early as the 1980s from coal ash basins.

Q Let's take a look at the EPA/TVA report first, Mr. Hart, which is Joint Exhibit 5.

A Okay.

Q And you indicate -- this is page 50 and 51 of your testimony -- that the presence of coal ash leachate within the basins themselves was at high levels, but that groundwater sampling was at lower concentrations, correct?

A Yes. Results of the study indicated that the water in the pour spaces of the coal ash basin contained high levels of TDS, boron, iron, manganese, and sulphate, pH as low as 2, and results of groundwater sampling indicated elevated levels of TDS, boron, iron, manganese, and sulphate, although at lower concentration than in the ash basin water.

Q And you indicate that the lower concentration is attributed to soil attenuation, correct?

A Attenuation mechanisms in the underlying native soil, correct.

Q And the conclusions and recommendations of the report are summarized in Section 2 of the report which begins on page 2.

A Okay. Yes.

Q And let me get to that page. Sorry. So Mr. Hart, tell me what the purpose is of a section of a report that deals with Conclusions and Recommendations.

A Well, it's conclusions about their -- their findings, and then also recommendations for -- based upon their findings for additional research or action or something like that.

Q And what's the importance to the reader of the report of the report's conclusions and recommendations?

A Well, it provides a summary, but it certainly is not intended to replace the actual findings of the report or the details of the report. In other words, you can't just read the conclusions and recommendations and say I know everything about the report and what it's going to tell me. You have to dive into the details and the data, as a scientist at least.

Q And I guess, Mr. Hart, my question -- maybe it's not a good question; maybe I didn't phrase it correctly -- but the reason to look back at documents such as this particular one, the 1980 EPA TVA report, or the 1988 Report to Congress, or the 1984 report about the Allen Plant, is to look to see what the industry knew and what the environmental community knew and what regulators knew at those various points in time, correct?

A Yes. I'd say in a general sense, yes.

Q And the purpose for that is to provide historical context around the documents that are being reviewed today in 2020, correct?

A Yeah. I'd say generally, yes.

Q And Mr. Hart, so you --

A Or some other time.

Q Yeah. Well, depending on -- depending on when the reader is actually reading it.

A Correct.

Q So Mr. Hart, your testimony certainly accurately states that -- the EPA TVA report's findings about coal ash leachate inside the basin and the impact of soil attenuation, but my question or my curiosity about it is, is why you didn't go further and state from the report's own conclusions, Conclusion Number 10, which is on page 3, and states soils containing a large percentage of clay are better attenuators than other types of soils, right?

A You asked me why I didn't include that?

Q Yeah.

A I mean, at least from my perspective it's an obvious statement. It doesn't need repetition, from my standpoint. There's no doubt that clay has a -- will attenuate metals from ash leachate or any other source more than sand, and that's true for just about any contaminant. So this is my report, so to me it wasn't a conclusion. It was an obvious statement.

Q Do you think it's obvious to lawyers reading your testimony or Commissioners reading your testimony?

A I don't know, but, you know, to me it's, you know, very clear that there is attenuation, and I say that, in the underlying native soil. So I think I've addressed that in a succinct way rather than replicating every conclusion and recommendation. And that's why I provide the exhibits, too. If someone had a question about what exactly that meant, they could read the actual exhibit.

Q So you don't think that it's important from the standpoint of a fair presentation as a scientist that your testimony should reflect the report's conclusion that clay soils are better attenuators, given that all of DEC's plants are built in clay soils?

A I don't know you can say all of DEC's plants are built in clay soils. Not all of Piedmont, especially as you get deep, as you get close to bedrock, you get into sand. And many of these basins, especially DEC basins, were placed into stream channels or at least surface water conveyance channels, and so rather than being on the top of a hill where you would expect more clay, they were actually put into the bottom of a valley where you're closer to bedrock and closer to sandy soil.

You can't make the blanket conclusion that all Piedmont soil is clay. It is at the surface in most cases, although we do have some areas with bedrock, but there's a great percentage of soil, especially as you get deeper, these basins in most cases were deep and installed in valleys where it is not clay. It is, in fact, a sandy material from the weathering of the underlying bedrock, what we called partially weathered rock.

Q Well, let's take a look at your -- the second document, Mr. Hart, which is the EPA Report to Congress, Joint Exhibit Number 13. You address the Joint -- the

Report to Congress at pages 51 and 52 of your testimony, right?

A Yes. Yes.

Q And on page 52, the first full paragraph on that page you indicate that the report -- in the report EPA documented current waste disposal practices on a state-by-state basis, correct?

A Yes.

Q But you didn't actually provide in your testimony the Commission with the details of what the EPA documented, do you?

A Yeah. I was focusing on, in this case, the -- the facilities for North and South Carolina.

Q Well, if you --

A That's all I'm saying.

THE WITNESS: I lost power on this thing, computer. I'm sorry. Go ahead.

MR. MEHTA: You all right?

THE WITNESS: Well, some of these I have. I lost my -- I guess I unplugged the power cord. I've got two computers here, one with the documents on it and one --

MR. MEHTA: Well, tell me when you're ready to proceed.

THE WITNESS: Go ahead. I'm sorry. Just waiting for it to reboot.

Q Do you happen to have available, Mr. Hart, the testimony of Marcia Williams, or is that in your computer that's rebooting?

A It is rebooting, but I can pull it up here, I hope.

Q Well, again, just subject to check, you can always check me, I'm going to refer to page 73 of her testimony where she indicates that the report indicates that only 10 percent of the 483 surface impoundments were lined, and in EPA Region 4, which essentially is the southeastern United States and includes both North and South Carolina, less than 2 percent were lined, correct?

A I'll have to bring up her testimony, but what page are you on?

Q Seventy-three (73).

A Okay. Sorry.

Q Did I accurately summarize what she said in terms of the percentages of lined and unlined ponds?

A Yes. That's correct.

Q But you didn't think it was important to provide the details of what the EPA documented in its report on lined and unlined ponds in the paragraph where you said the EPA did state-by-state surveys of those ponds, correct?

A Yeah. Well, my position isn't on whether ponds are lined or unlined. They were unlined, so that's a given fact we have. The question is once groundwater -- from my standpoint, at least, is once groundwater contamination was detected, what did DEC do in response to that in accordance with North Carolina regulations? So it's really not important to me whether it was lined -- there were -- whether people were doing, lining or not lining impoundments, as much as it was about what we were seeing. I think I do talk about some lining, but it was more important to me to see what people knew about groundwater contamination from the unlined lagoons.

Q Well, if you go on, I guess down at the bottom of page 52 --

A I'm sorry. Of what?

Q Of your testimony.

A Yeah.

Q You talk about various technologies available, for example, lining, liners to deal with what you indicate the report said was a "leaky pond issue," correct?

A Right. That lining was becoming more common because of concern that groundwater contamination may occur from leaky ponds.

Q Well, did you mean by that paragraph to give the reader of your testimony the impression that DEC should have been retrofitting its ash basins with liners back at this time frame?

A You talking about in 1988?

Q Sure.

A No. That was not my intention. My intention is to say that in response to the ground--- that during this time period there was knowledge that unlined lagoons, such as at the DEC facilities, could lead to groundwater contamination, which is, in fact, what -- what was found when groundwater monitoring started. So it shouldn’t have been a concern -- I mean, it shouldn't have been a surprise when groundwater monitoring indicated that there was contamination associated with the ponds. I mean, so from that standpoint what I’m saying here is lining was becoming more common because people were finding groundwater contamination associated with leaky ponds.

Q So if a reader came away with the impression that you were advocating that liners -- ash ponds back then should have been retrofitted with liners, that would

be a misimpression, correct?
A That's correct. Now, once they found groundwater contamination, I mean, there are certain things that can be done to limit contamination, further migration, and control the source, which could include lining, but there's many other things that could be done, too, as I discussed in my testimony.
Q And the EPA itself made no recommendation that existing ash ponds should be retrofitted with liners, correct?
A I don't recall that. What, in this document?
Q Yes.
A I don't recall that.
Q And this document, just like every other document from the historical time period that we've been looking at, has a section on Conclusions and Recommendations, does it not?
A It does, yes, but, again, that's not intended to be a substitute for the actual data or foundation behind the report, in my opinion.
Q And the conclusions and recommendations of the EPA in its 1988 report are in Chapter 7 of the report, correct?
A Yes.

Q And if we look at Chapter 7 -- I guess it starts -- it's probably pretty far down at the -- towards the end.

A Hold on. Twenty-one (21).

Q Yeah. It's your Exhibit 21 and Joint Exhibit 13.

A Yes.

Q Looks like it's -- well, again, in Joint Exhibit 13 because the pages are sequentially numbered, it's Doc. Ex. 6710, but if you're looking at your exhibit, you'll just have to find Chapter 7.

A I found Chapter 7.

CHAIR MITCHELL: Mr. Hart, you are trailing off. Can you make sure that you are speaking directly into or towards your microphone just so the court reporter gets your complete sentences?

THE WITNESS: Okay. I'm sorry about that.

CHAIR MITCHELL: Thank you.

A Yes. I'm on Chapter 7. Sorry.

Q And if you go to page 7-7, which in Joint Exhibit 13 is Doc. Ex. 6716, there's a section of the Conclusions and Recommendations that says -- that talks about evidence of environment transport of potentially hazardous constituents, correct?

A What page, 7-7?
Q 7-7.
A Okay. What number are you talking about, bullet number?
Q It’s Section 7.2.5 at the --
A Okay.
Q -- bottom of the page. Are you there?
A Yes.
Q And the first conclusion of the EPA is that migration of potentially hazardous constituents has occurred from coal ash combustion waste sites, correct?
A Yes.
Q So they indicate that they actually have seen what you say was found, for example, at the Allen plant?
A Right.
Q Not that it’s hazardous concentrations, but that constituents were in groundwater, correct?
A Right. Above the drinking water standards.
Q Well, at Allen they were probably not above the drinking water standards, but they perhaps were above whatever the 2L standards were at the time, correct?
A I’d have to go back and check. I was talking about this. They’re saying that there are exceedance -- I’m talking about the 1988 report.

Q Okay.

A About how there are exceedances of drinking water standards for cadmium, chromium, lead, selenium, and arsenic.

Q Right. And so the EPA, in fact, found that there were exceedances of drinking water standards at some power plants, correct?

A That's correct.

Q And the second conclusion that they drew was that this, what they called contamination, does not appear to be widespread, correct?

A Right. It says -- yes. Not widespread, but many utility waste management sites had at least one exceedance. Not widespread, but at least some exceedances, yes.

Q Okay. And the third conclusion that the EPA reached was -- and this is on page 7-8, number 3, when groundwater contamination does occur, the magnitude of the exceedance is generally not large, correct?

A Right. They're usually 10 to -- well, I guess and that's relative. They tend to be no more than 10 to 20 times the primary drinking water standards, although some observations were greater than a hundred times the primary drinking water standard.

Q And the fourth conclusion that the EPA made with respect to groundwater impacts was human populations are generally not directly exposed to the groundwater in the vicinity of utility coal combustion waste management sites, correct?

A Correct.

Q And the report makes recommendations in addition to conclusions, does it not?

A After it discusses evidence of damage from coal ash plants, it does have recommendations, yes.

Q And that's starting on page 7-11, correct?

A Yes.

Q And for the Joint Exhibit 13 reference, it's Doc. Ex. 6720. And the recommendations are there to provide guidance, the EPA's guidance about what it thinks ought to happen in the future, correct?

A Well, it says they're preliminary, but there could be other recommendation, but, yes, generally the recommendations would have some information on additional studies or how to address some of these concerns, yes.

Q And the -- I mean, Ms. Williams was the head of the office that wrote this report, so we can ask her perhaps what's meant by preliminary, but the first recommendation is that the EPA has concluded that coal combustion waste streams generally do not exhibit hazardous characteristics. Do you see that?

A Yes.

Q And that the EPA doesn't intend to regulate it as a hazardous -- as a hazardous substance under Subtitle C. Do you see that?

A I read this as it's not a hazardous waste.

Q Hazardous waste. Excuse me.

A Not a hazardous substance.

Q Yeah. We're talking RCRA, not CERCLA. I was mixing up those terms. There's not a hazardous waste under the RCRA Subtitle C, correct?

A Correct.

Q And they go on to say that their conclusion or at least tentative conclusion is that "Current waste management practices appear to be adequate for protecting human health and the environment." Is that right?

A Where is that?

Q The very next sentence after the underlined sentences in that paragraph.

A Right. EPA's tentative conclusion.

Q And its tentative conclusion is that "Current waste management practices appear to be adequate for protecting human health and the environment," correct?

A That’s what it says. Now, I -- I read this under the context of RCRA. In other words, it shouldn’t be a RCRA hazardous waste if it’s under that heading.

Q Well, the EPA arrived at that conclusion and made the recommendations that it made knowing that 98 percent of the ash basins in the southeastern United States were unlined and that every single one built by Duke Energy Carolinas at the time was unlined, correct?

A Yes, I believe so. Yes.

Q And did you not think that that is a conclusion that ought to be presented in your testimony in order to make it fair and balanced?

A Well, I was -- I mean, you can use it for different things. I mean, there’s -- you know, that’s why I attached the document itself, because there’s no way I could go through all the conclusions and recommendations in these reports. I mean, as I mentioned before, it also has a discussion of the Allen plant, where it says high concentrations of manganese are in groundwater at this facility. It’s going to continue to migrate. It’s not in steady state, and there’s concentrations that are, you know, 120,000 parts per billion versus the standard of 50. So I could have included that as well, but I didn’t. There’s no way I can include everything in this report, that, to me, I was just using it for some of the information that I presented here. But there was no intention on my part certainly to not include a balanced report. I even say that, that --

Q So Mr. Hart, if you --

A If I can finish my -- please.

Q Sure. Oh, of course. I’m sorry.

A -- that, you know, the understanding of groundwater contamination evolved over time. It did, associated with coal ash plants. So, you know, the intention was not to -- if I didn’t include some specific recommendation in a 386-page document, it wasn’t intention to hide it. That’s why I attached it. There’s just no chance that you could include all the recommendations and conclusions in the report. I was providing the reader some information that I gleaned from it that was important to my evaluation.

Q Mr. Hart, the EPA was clearly aware of the underlying data that you just recited about the Allen plant, was it not, when it wrote this report?

A The EPA was, yes, and it’s a violation of the 2L standard, to which DEC did nothing until it was required to do so in 2014.

MR. MEHTA: Chair Mitchell, I'm going to move on to a different subject. I don't know if this is a good time for a lunch break, or I can keep going.

CHAIR MITCHELL: Why don't you keep going, Mr. Mehta. We'll take a lunch break at 12:45.

MR. MEHTA: Very good.

Q Mr. Hart, let's take a look, then, at the third of your 1980s documents, which is the 1984 Duke Report on Allen which is Joint Exhibit 9. And I think you found it earlier --

A Yeah. I had it earlier. Yeah. Here it is.

Q -- by reference to whatever it was marked as in the prior case, which I think was a Wells cross exhibit.

A Yeah. I have it.

Q And Mr. Hart, you talk about this report at pages 57 and 58 of your testimony, correct?

A Yes.

Q And that's placed in the section, or the sort of lead-in question is about your review of internal -- or documents internal to DEC regarding actual or potential groundwater contamination, correct?

A Yes. I'm sorry. Yes. It's in that section, but --

Q This particular document, though, Mr. Hart, was published, was it not? I mean, it’s not just an internal DEC document, correct?

A I don’t know. I don’t know that. The report by Little, and I think this was done in parallel with the latest Little report, was published, but I don’t know if this one was published.

Q I guess on that subject, Mr. Hart, if you -- you indicate in the last line of page 20 of your prefiled testimony, starting there and going on to the top of page 21, that one of the “proven” damage cases cited by the EPA in the document under discussion there, which I believe is the 2010 Proposed CCR Rule, correct?

A Yes. And it’s referencing the 2007 Coal Combustion Waste Damage Assessment report.

Q Right. And you indicate there that one of the “proven” damages -- damage cases is the Belews Creek fish kill situation, correct?

A Correct.

Q And certainly, DEC did not hide that incident, did it?

A Not that I’m aware of. It would be hard to hide a fish kill.

Q And they actually do know that it was the subject of a published document because Joint Exhibit 11 is that document. It's a -- the proceedings of some engineering group, proceedings of a symposium sponsored by the Energy Division of the American Society of Civil Engineers in conjunction with the ASCE Convention in Detroit, Michigan, October 24th, 1985, correct?

A Are you -- I'm sorry. Are you referencing to --

Q Yes. I'm referencing Joint Exhibit 11.

A Oh, okay. Okay. I don't have that, but --

Q And this particular incident, the fish kill, impacted surface waters, basically Belews Lake, correct?

A Yes. That's correct.

Q And DEC addressed the issue by, among other things, modifying its production to shift to dry handling of the fly ash produced by the Belews Creek power plant, correct?

A That's correct. So the question is if they could -- from my standpoint, is if they knew there was an issue with surface water and they addressed it with dry ash handling, they had -- so they address this issue with metals. They later find there's a groundwater issue that have metals. It's not addressed. So is surface water more important than groundwater, I guess, in Duke Energy's beliefs? That's the impression you get, at least for me.

Q Well, that -- that’s the impression that you draw from the confluence of events here, correct?

A Well, yeah. And they certainly -- because there’s a fish kill, they addressed it, right? But there’s no fish kill at groundwater, so even though it’s a resource of the state, it somehow is less important from Duke Energy’s standpoint. That’s the impression that I got.

Q Well, we’ll let Mr. Wells and Ms. Bednarcik, when she’s back on, speak to that, because I’m really trying to just examine you on your testimony regarding these documents.

And in any event, Mr. Hart, the selection of that particular remedy, the conversion of fly ash to dry handling, was done in conjunction with the DEQ, was it not?

A I don’t know. As far as I know, it was. Now, this is 1984, so I don’t really have any documents from that time period related specifically to that, but I would think so, yes. Yes. So they certainly had the ability as early as 1984 to convert facilities to dry fly ash handling to reduce the concentrations of metals that were entering surface water, and that same water was also

infiltrating into groundwater.
Q Mr. Hart, the plant modifications did not include dry ash or dry handling of bottom ash at the Belews Creek facility, did they?
A It did not, not until 2018.
Q Yeah. And despite continuing to sluice bottom ash to the Belews Creek ash ponds, this fish kill issue did not resurface, did it?
A Well, no. I mean -- yeah. So fly ash would generally tend to have much higher concentrations of metals in it than bottom ash, so it would have been less likely to have an issue. But I understand they also -- not only did they convert to dry handling, my understanding is they also added, I believe, ferric chloride to help settle out some of the metals to the water before it was disposed in the basin. Now, that leads to another reason why you have high concentrations of iron, potentially, because you added a treatment chemical to remove some of the metals.
Q And back to the 1984 Allen report, Mr. Hart, that you address at page 57, and you indicate on page 57 of your testimony --
A Okay.
Q -- that the report dealt with a study of

leachate from coal ash and potential impacts upon groundwater, correct?

A Yes.

Q And the Executive Summary of that report, Mr. Hart, which is Joint Exhibit 9 --

A Okay.

Q -- it's on Doc. Ex. 9395 in the joint exhibit, but it's essentially the first page before page 1 in the report that you're probably looking at, it's an unnumbered page --

A Yes. Executive Summary.

Q -- it indicates, starting in the middle of that paragraph, "Groundwater monitoring in 13 test wells installed by Duke Power around a retired inactive ash basin found over a four-year period that drinking water quality was maintained in the wells downgradient of the sites after groundwater stabilization had occurred following well installation," correct?

A Yes, but what they're talking about is further downgradient of the ponds, not next to them.

Q I understand. And the second sentence says "Additional groundwater monitoring and soil testing from the same sites done by an EPA contractor," and that's Arthur D. Little, correct?

A That’s my understanding, yes.

Q So additional groundwater monitoring by Arthur D. Little for the EPA “also found the downgradient groundwater to be drinking water quality, and suggested the high ion exchange capacity of the soil lining the ash basin to be the mechanism preventing migration of soluble metals from the ash basins,” correct?

A Correct.

Q And the conclusion that the Executive Summary draws is the last sentence, “These field and laboratory studies confirm that wet disposal of coal ash by Duke Power has no significant impact on groundwater,” correct?

A Well, yes. That’s what it says.

Q Well, why didn’t these conclusions in the Executive Summary make their way into your testimony, Mr. Hart?

A Well, they do. I clearly say that there was groundwater contamination. "Results of groundwater analyses conducted near the ash basins indicated that concentrations of arsenic (up to 112.5 micrograms per liter versus the 2L standard at the time of 50 micrograms per liter) and selenium (up to 19.5 micrograms per liter versus the 2L standard at the time of 10 micrograms per liter) were detected above standards in two of the wells;

however, the groundwater impacts did not extend downgradient from the ponds."

And I go on to say -- and I'm reading on page 57, lines 19 and on, "The study indicated there was a leachate plume emanating from the ash basin into groundwater, but the apparent high ion exchange capacity of the underlying soil limited downgradient migration." I did. Why are you accusing me of not including the recommendations when I -- I mean, the summary when I did?

Q Well, I'm looking for some acknowledgement, Mr. Hart, in your testimony, and I didn't find it, perhaps you can show it to me, that "These field and laboratory studies confirm that wet disposal of coal ash by Duke Power has no significant impact on groundwater."

A Because I disagree with the conclusion. It's not accurate. It did have an impact on groundwater. It didn't extend downgradient. And this is a Duke Power report prepared for Duke Power. Of course, they're -- they may not say that their coal ash is going to have an impact on groundwater. It did have an impact on groundwater. We see it in this report and we see it in the Arthur D. Little report. To say that it had no significant impact ignores that fact that there are groundwater rules and standards. It did not extend downgradient. It also ignores the fact that the ion exchange capacity may be exhausted in the future, and it was. It did lead to groundwater contamination.

Q Mr. Hart, look, if you would, at page 40 and 41 of your deposition testimony.

CHAIR MITCHELL: All right. Mr. Mehta, I believe this is a good time to break for lunch.

MR. MEHTA: Chair Mitchell, actually, if we could get one question in, we will be done with the subject and can break and come -- go to a completely different subject.

CHAIR MITCHELL: All right. Well, I'll allow you to proceed. You are standing between us and our lunch break.

MR. MEHTA: I understand.

CHAIR MITCHELL: I'll allow you to proceed.

MR. MEHTA: And I will try to be very brief. Of course, one question for a lawyer always turns into a few more, but --

CHAIR MITCHELL: I'm very aware of that.

MR. MEHTA: I understand.

Q So Mr. Hart, are you at pages 40 and 41 of your deposition, which is Exhibit 1?

A Yes.

Q And in the -- at the very bottom of page 40, your testimony concerns the report of the Allen plant, which is what we’ve just been talking about, the Joint Exhibit 9, correct? Is that right?

A Well, I don’t see --

Q Well, I’m looking at page 40, line 24,”...even the report that was done at the Allen plant...” Do you see that?

A Right.

Q And you indicate the conclusion from that was that there was groundwater contamination, but it wasn’t migrating very far. Do you see that?

A Yes.

Q And you indicate that they felt, "they" meaning the authors of the report, felt there was significant attenuation capacity in some of the soils. Do you see that?

A Yes.

Q And then you say “Now, it turned out to not necessarily be correct, but that was the conclusion at the time.” Do you see that?

A Yes.

Q And I asked you at line 6 on page 41, “Are you quarreling with the conclusion at the time,” correct?

A Correct.

Q And your answer was, starting on line 8, “No. I think over time a lot more data was developed, which is not uncommon,” correct?

A Correct.

MR. MEHTA: Chair Mitchell, I’m done. It took three minutes. Sorry. But we can move on to a different subject after lunch.

MR. MEHTA: Thank you, Chair Mitchell

CONTINUED CROSS EXAMINATION BY MR. MEHTA:

Q Mr. Hart, good afternoon. And what I would like to do is turn, if you would, with me to your -- the issues raised in your supplemental testimony. And I realize -- at least I think I realize that as a result of your errata filing, the supplemental testimony is now included in what you call your "entire testimony" and the page numbers are different. But originally you filed testimony with respect to your attempts to quantify cost disallowances for Duke Energy Carolinas, correct?

A Yes. The supplemental testimony, that's correct.

Q Okay. Now, I think similar to the morning session, Mr. Hart, you may as well have available to you and handy two documents that we will be referring to, I suspect, repeatedly. One of them is Duke Exhibit or DEC Exhibit 5 and the other one is DEC Exhibit 6.

A Okay.

MR. MEHTA: And Chair Mitchell, if we could mark DEC Exhibit 5 as DEC Hart Cross Examination Exhibit 5, that would be marvelous.

CHAIR MITCHELL: All right. The document will be so marked.

(Whereupon, DEC Hart Cross Examination Exhibit Number 5 was marked for identification.)

MR. MEHTA: And if we could mark DEC Exhibit 6 as DEC Hart Cross Examination Exhibit 6, I would appreciate it.

CHAIR MITCHELL: All right. The document will be so marked.

MR. MEHTA: Thank you, Chair Mitchell.

(Whereupon, DEC Hart Cross Examination Exhibit Number 6 was marked for identification.)

Q And Mr. Hart, just to level set us, the document marked as DEC Hart Exhibit 5 -- Cross Examination Exhibit 5 is your workpapers associated with your quantification of disallowance, correct?

A Yes. I'm sorry. I was in my -- I was in my testimony Exhibit 5. Sorry. Yes. Workpapers. Yes. Sorry. I'm there.

Q And DEC Hart Cross Examination Exhibit Number 6 is that portion of your deposition taken April 28th, 2020, by video that deals with your supplemental DEC testimony, correct?

A Yes, it is.

Q Now, Mr. Hart, the quantification that you presented to -- in your supplemental testimony is in two basic buckets, correct, if I'm looking at it correctly. One deals with the disallowance of public water supply hookups and the other dealing with various amounts based on what you call your time value of money analysis. Did I frame that correctly?

A Yes. The water supply connection removal and then what I call the time value of money. It may not be the actual accounting correct term, but it's just an adjustment for inflation over time. And then I also took out the Charah contract cost and didn't consider that in my analysis at all.

Q Okay. And so that when we look at your workpapers, Cross Examination Exhibit 5, even though it deals with a number of different time frames, 1989, 1995, 2003, 2010, in each of those time frames you removed the alternative water supply cost amount, which is about 17 and a half million dollars, from each of those time periods, correct?

A Correct.
Q And we'll come back to the alternative water supply in a few minutes, Mr. Hart. And you also, as you just indicated, removed the Charah fee item from each of the time periods, correct?
A Yes, yes. I -- yes, I removed that. I just didn't consider it. It didn't factor into my evaluations. I'm not making a conclusion about whether it's reasonable or appropriate or not. I just took it out because I didn't know how to address its money. It's a contractual issue.
Q So you're actually expressing no opinion in this case on whether the Charah fee should or should not be included in DEC's recoverable costs, correct?
A That is correct.
Q Now, beginning on page 127 of your supplemental testimony, which I think under the errata filing is now page 128 of your entire testimony, you set out a series of bullet points that you say are illustrations of increased costs, correct?
A Yes. Correct.
Q And the first one deals with the impact of acceleration, Mr. Hart; is that right?
A Yes.

Q And in order --

A Yes. Accelerated time frames to do work, yes.

Q And in order to quantify the impact of acceleration, you would need to compare the costs actually incurred in their accelerated mode to what they would have been in a nonaccelerated mode calculated to a reasonable degree of engineering certainty, correct?

A Well, it's just a general statement to come up with an actual number, yes. Now, I did not factor in -- the only thing I took into account was inflation, so I did not take into account, you know, in terms of cost disallowance the accelerated actions. My point is just based upon my experience, the accelerated actions can lead to increased cost typically because you can't necessarily dispose of coal ash at your own facility. You have to dispose of it offsite. So, again, that didn't factor into my ultimate analysis cost; just an evaluation statement about how costs are likely higher because of the accelerated actions caused by the Dan River spill.

Q And Mr. Hart, you're actually not an engineer, so I guess even if you wanted to make that assessment, a quantification assessment of the impact of acceleration, you would not be able to do that, would you?

A No. I think I could if I wanted to. It's not -- you know, it's a -- it would be analysis of what the cost would be under a nonaccelerated time frame versus an accelerated. It's not necessarily an engineering thing.

Q So you don't -- you think somebody who is not an engineer and not an expert in engineering could do that analysis and present a comparison of costs on an accelerated versus nonaccelerated mode?

A Well, I guess it depends on what costs you're talking about. If it's just remediation costs, coal ash removal, I think certainly like I could do that. If you're talking about constructing -- or somebody like myself could do that, an environmental professional. If you're talking about accelerated cost to do a dry ash conversion, that would not be my area.

Q Okay. In any event, you didn't do a comparison of accelerated versus nonaccelerated cost, did you?

A I did not, no.

Q And your second bullet on page 127 of your supplemental, which, again, I think is page 128 of your entire testimony under the errata format, indicates that regulators and the public lost confidence in DEC and prompted higher cost requirements, correct?

A Yes.

Q And, likewise, you have not calculated and presented in your testimony the dollar difference between what the costs would have been had regulators and the public not lost confidence in DEC and what the actual costs were, correct?

A That is correct.

Q And in your third bullet you indicate that had DEC taken action sooner, it would have been able to include cost of service earlier while the plants were in use, correct?

A Correct.

Q You’re not a ratemaking expert, are you, Mr. Hart?

A No, I’m not.

Q So in order to actually calculate that difference, you would have to make an assessment of the amount by which the rates were too low in the past, and you have not made that kind of assessment in this case, have you?

A I have not, no, other than -- I mean, I have not done a specific calculation, no.

Q And if you look back, for example, Mr. Hart, at page 127 of your supplemental testimony -- excuse me -- 126 of your supplemental testimony, which I think might be 127 of the reformatted entire testimony, you indicate that DEC should have instituted a systematic plan sooner, including conversion -- converting to dry ash handling, correct?

A Well, yeah, and beginning the process of converting to dry ash handling, eliminating other waste streams, developing basin closure plans, and evaluating methods to reduce the environmental impact while the basins are still operational.

Q And in order to quantify, just for example, the disallowance of costs involved with that systematic plan and, just for example, on dry ash handling, you would have had to establish, with a reasonable degree of engineering certainty, what it would have cost to make -- have made the dry ash conversion at some earlier point in time, which you have not done and which you do not possess the expertise to do; is that correct?

A I mean, not other than the increase in cost related to inflation, but not specifically to any dry ash handling, diversion of waste streams, that kind of thing. Those are certainly part of the costs, as I understand it, that are being requested for, so to the extent they're included in them, I looked at different time periods and what inflation did to those costs over time, assuming the cost today.

Q Well, in order to quantify the impact of -- or, you know, in order to fully quantify the impact of earlier dry ash handling systems being put into place, you would also have to quantify the impact of DEC being entitled to recover those earlier incurred dry ash conversion costs, plus a return on its increased rate base over the period, whatever the period is, from the time that the dry ash conversion took place to today, correct?

A I'm not sure I know how to answer that. I don't know that I have enough expertise on ratemaking to know that.

Q Well, Mr. Hart, let's actually look at what you did do as opposed to what you didn't do. And why don't you turn to Cross Examination Exhibit 6, which is the sort of part 2 of your deposition testimony.

A Okay.

Q And Mr. Hart, at pages 22 and 23 of Exhibit 6, you testified that you discussed the idea of doing a time value of money analysis with the Attorney General's Office as early as January 2020, correct?

A Where do I say January 2020?

Q Looking at the top of page 23.

A I see it. Yes. Correct. Probably January, yes, 2020.

Q And your testimony, your original testimony, not the supplemental, was filed in March of 2020 without that analysis, right?

A That’s correct.

Q Why didn’t you include that analysis?

A Well, as I think I indicated in my deposition that we just had some -- you know, there were some uncertainty about the -- how we wanted to approach cost, whether we wanted to include specific costs or not, and so we decided not to include specific costs in the original testimony. But then sometime after I filed that original testimony, we discussed it, that the Attorney General’s Office did want to include some specific costs in my testimony.

Q And looking again at Exhibit 5, Cross Examination Exhibit 5, the time periods at which you performed the time value of money calculations were 1989, 1995, 2003, and 2010, correct?

A Correct.

Q But initially you were only going to perform the calculations for 2003 and 2010; is that right? Is that what you indicate at page 25 of your deposition?

A Yes. Early 2000s to 2009 time frame or 2010. That’s correct.

Q And it’s the attorneys for the Attorney General’s Office that asked you to go back to the 1980s and 1990s, correct?

A Yes.

Q Are you in the habit, Mr. Hart, of letting your client tell you how to do your analyses?

MS. TOWNSEND: Objection for the record.

A Well, I certainly listen to my clients as I --

CHAIR MITCHELL: Mr. Hart -- Ms. Townsend, would you state the basis for your objection?

MS. TOWNSEND: Yes. Client-attorney privilege. You know, we -- what our discussions were, et cetera, we objected to them at the time of the deposition and we object to them now.

CHAIR MITCHELL: Mr. Mehta?

MR. MEHTA: Well, I’m looking at the deposition, and Mr. Hart says that they, meaning the attorneys, suggested going back to the earlier times. And I think to the extent that that is even part of the attorney-client privilege, which I doubt sincerely, it’s been waived.

CHAIR MITCHELL: All right. I’ll allow the question. Overrule the objection.

Q Mr. Hart, are you in the habit of letting your clients tell you how to do your analyses?

A No, but I'm certainly in the habit, as I think we all are, of listening to our clients and taking their suggestions, and so I think the thought process was, is we would give different time frames and let the Commission determine which time frame they felt most appropriate.

Q And in any event you did add, at the suggestion of the Attorney General's Office, 1989 and 1995 to your calculations, correct?

A That's correct.

Q Mr. Hart, why don't we walk through the calculation just using 1989 as an example. And the -- but the -- and the methodology you used for each of these years is basically the same, correct?

A Yes. That's correct.

Q And you started -- and you can see this on Exhibit 5 -- you start with a total cost figure of a shade under $406 million, correct?

A Correct.

Q And you got that from Ms. Bednarcik's direct testimony; is that right?

A Yes. Well, it was -- yes, I did.
Q And I think we discussed this at your deposition, but that number, that 400 and -- almost $406 million number, is a system number, not a North Carolina retail number, correct?
A That’s what I understand, yes.
Q And what that number represents is the cost incurred on a system basis by DEC for coal ash basin closure activities from January 1st, 2018, through June 30th, 2019, correct?
A I would have to go back and check Ms. Bednarcik’s testimony, but I believe that’s the correct time.
Q And then you took that total cost number, you removed, as we discussed earlier, the Charah fee, correct?
A Correct.
Q And the water supply, and you come up with what you call a revised cost of about $342 million, right?
A Correct.
Q And what you did next was work your way back in time to 1989, and using average inflation rates came up with what you call the equivalent cost, correct?
A Well, it would just be the increase in cost

from 1989 to present, yes, for the cost they're asking for now, considering inflation, just inflation.

Q Well, I'm looking again at Exhibit 5, Mr. Hart, and there is a number sort of to the left of the revised cost of $342 million of $171,500,000; is that right?

A I'm sorry. Where are you? Which number?

Q I'm right below your revised cost and a little bit to the left, 171---

A One hundred seventy-one thousand, five -- a hundred and seventy-one million, five hundred, yes.

Q Okay. And the -- there's a number right next to it which I think is the average inflation rate between 1989 and the time frame that you were evaluating, correct, today?

A Well, to 2014. So you could -- two ways to look at it. One is 1989 to 2014, or you could just move up to five years earlier and you basically get the same number, but, yes, over a 26-year period.

Q Okay. And that -- and then you keep going across the page, there's some words, "Net present value of approximately $342 million over 26 years." Do you see that?

A Yes, yes.

Q And then right below that there's some more words, “Difference between revised cost and equivalent cost 26 years earlier,” right?

A Correct, yes, if the work had been done at that time, right.

Q Yes. And if we looked actually at the Excel spreadsheet from which your workpapers from which Exhibit 5 are derived, and you looked at the formula there, you would see that you were subtracting $171,500,000 from the $342 million figure, correct?

A Correct.

Q And so when you say the difference between revised cost and equivalent cost 26 years earlier, equivalent cost 26 years earlier equates to $171,500,000, correct?

A Yes, yes, roughly.

Q And you arrived at that figure, 171,500,000, through trial and error, correct?

A Correct, until the number -- the calculated number, which is to the right of the inflation rate, .027, was roughly equivalent to the revised cost of 342 million, one hundred and some change, yes.

Q And what that dollar figure represents, the equivalent cost, $171,500,000, is the cost expressed in 1989 dollars of the work done in 2018 and the first half of 2019, which in today's dollars would have been about $342 million, correct?

A Yes, if the work had either been done or the money had been set aside, yes, or accrued.

Q And to make it work, to make the equivalent cost actually be an equivalent cost, you have to assume that exactly the same work as was done in 2018 and the first half of 2019 would have been done in 1989, don't you?

A Yeah. That is the assumption, right. And so in my thought process that would overestimate because you're starting at a much higher cost. In other words, there's a lot of things that -- for example, full removal of coal ash may have not been an option -- may have not been conducted in 1989, or beneficiation probably would have not been done because it was an unproven technology, so my calculations, even though they assume these things would have happened in 1989, are actually on the low end of what would be excluded because there were much more lower cost alternatives available back in 1989.

Q Well, you actually have no idea what would have to have had -- have to have occurred in 1989, do you, Mr. Hart?

A Well, you know, it just depends on what would have happened and, no, I can't say for certainty. Nobody can. But you can -- you can also go back. You can't say I can't know what something costs until I actually do it in something like this because you would never have ratemaking, right, where you look forward. You have to look forward to the future for some of the costs, and so in order to do that -- you can't always do that with certainty, so you have to look back sometimes.

Q Mr. Hart, you don't know if in 1989 the Company would have had to do more, do less, what the Commission would or would not have allowed, what the Commission would or would not have disallowed, or any of those things, do you?

A I don't, but I can say that there were certainly lower cost alternatives available to the Company to start planning. I didn't say they had to do all these things at a particular time to shut down, but they did need to respond to the groundwater contamination at some point and do some of these things, like dry ash conversions, closure of the ponds. And certainly back in 1989 people were closing out ponds in this state, and they were doing it by closing in place, and people were addressing groundwater contamination and things of that nature, so it's not something that didn't occur in 1989.

I can’t say for certainty what would have been required, no.

Q And you did not factor at all in your time value of money disallowance recommendation for 1989 or any of the other years the impact of DEC being able to recover and earn on some or all of those costs incurred at earlier points in time, correct?

A That’s correct. I did not.

Q All right. Now, Mr. Hart, in the final step of your time value of money analysis for 1989, you took what you call the equivalent cost, which is that $171,500,000 figure, and subtracted it from 342 million, the revised cost, to come up with a difference of approximately $171 million, correct?

A Correct.

Q So that -- what you did was subtract a figure expressed in 1989 dollars from a figure expressed in today’s dollars, and indicated that the difference was meaningful to your analysis, correct?

A Right. That’s the additional cost because of inflation from $171 million, roughly, to $342 million today.

Q But Mr. Hart, those two figures, 171,500,000 and 342 million are the same dollars for the same work, just expressed in dollar values reflecting different points of time; isn't that correct?

A Well, that's only correct if you actually did the work or set aside the money, but no one did that. So you can't say I had $171 million set aside. Duke didn't do that, and so it's not the same money. It can't be. If you're just saying, well, all I had to do was say I'm going to spend 171 million in 1989 and now it costs me 342 million, that's -- you didn't spend the 171 million back in 1989, nor did you set it aside. It's not the same money.

Q But it's the same figure, just expressed at different points in time and adjusted by inflation, under your own analysis, isn't it?

A It's the same figure if the money had been spent or accrued.

Q But the whole purpose behind what you're doing, Mr. Hart, is to say "x" amount of money should be disallowed, and the "x" amount of money is the equivalent amount of money that is being spent today, just 26 years earlier, according to your analysis, in the year -- for the year 1989; isn't that right?

A I don't see it that way. What I see is because of Duke's delay in addressing its groundwater contamination, it had to spend extra money because it delayed, and because of inflation, that money is more today than it would have been previously and, therefore, it's going to cost more. And should the ratepayers today -- their delay be foisted upon the ratepayers today for their delay and inaction when they knew they had groundwater problems at their coal ash basin a long time ago that they had to address in some fashion? It didn't have to be closure, necessarily, but it could have been dry ash conversions like they did for selenium in surface water. They could have been starting a closure process. So I disagree with what you're saying.

Q Mr. Hart --

A If I have $50,000 in the -- you know, say I'm going to put $50,000 away and I put it in an account, yes, from inflation, and it's earning an inflation rate, yes, the time in the future would be more money, but if you don't put that money away, that money -- you know, if I have zero in my account, it doesn't cost me $50,100. I just don't magically have that.

Q Mr. Hart, in your deposition, Exhibit 6, I asked you if you knew of any standard text or peer-reviewed article that supports this just subtraction methodology that you've been talking about. Do you recall those questions?

A Yes, yes.

Q And your answer was that you don’t know of any; is that right?

A Well, I don’t -- where are you, because I think I had some qualifications on that, but it’s -- you know, I think it’s a fairly simple analysis to do an escalation or de-escalation for inflation for money, for cost over time. I mean, it’s -- Duke did it in all their -- in their projections for the future. They use an inflation rate. Why do that if it’s all the same money? Why would you account for inflation? If it’s the same money, I don’t have to account for inflation, right, but it’s not the same money.

Q Well, Mr. Hart, I’m looking at page 76 of your deposition, line 2. That’s Exhibit 6. Question, “So the answer to my question, is there a standard text or a peer-reviewed article that” -- should say no -- perhaps there’s an error in transcription or perhaps I just said it wrong, but your answer was you don’t know of one, correct?

A Well, I said to me it’s subtraction. I don’t know any specific -- "I don’t know what specific methodology you would want, but I’m not aware of any other than just it’s subtraction.”

Q Okay. So you, in fact, do you not know of any standard text or peer-reviewed article or journal that supports your “just subtraction” methodology and application of just subtraction to a time value of money methodology, correct?

A I don’t, other than to say it is standard practice for us to look at cost increases from inflation over time for certain -- for projects like this. What is the delay -- is the delay going to cost me more, and the answer is yes. And so those are factors we've taken into account. We have to do financial assurance calculations for our clients for reserves analysis, and so, you know, the State now requires you to do an inflation adjustment. Well, if it’s the same money, why would I have to do an inflation adjustment every year? It’s because the -- it’s going to cost me more now. I don’t have enough money anymore, right? So to me, it’s a standard methodology.

Q But you can’t point to a standard text or a peer-reviewed article that indicates that just subtraction in this context is a standard methodology, right?

A Again, it’s based upon my experience, so that’s what I'm relying upon.

Q Well, Mr. Hart, let's switch over to the 17-and-a-half-million-dollar disallowance recommendation that you've made dealing with alternative water supplies.

A Okay.

Q And, again, just to level set us, see if I -- see if I frame this correctly -- the 2016 amendments to CAMA, Coal Ash Management Act, obligated DEC to establish permanent replacement water supplies to replace drinking water supply wells located within a half-mile radius of the compliance boundary for its coal ash basin sites, correct?

A Yes. That's my understanding, yes.

Q And those amendments became effective in July of 2016?

A That sounds right, yes.

Q And in your supplemental testimony at page 128, which I think may be 129 now in your errata testimony, you testified that the alternate water supply requirement was another manifestation of the lack of confidence on the part of regulators and the public, correct?

A I don't believe I used that terminology.

Q Well, you're right. You're right. That was actually in your deposition. So if you turn to your deposition, page 176 and 177, I believe that’s where you talked about it.

A A hundred and twenty-six (126), is that what you said?

Q One seventy-six (176) to --

A Oh, 176.

Q -- to 177.

A One seventy-six (176). Okay.

Q I’m sorry. We have to go back to your first deposition. That would be Exhibit 1.

A Yeah, yeah. Yes. Right. First deposition. Yes. I see here.

Q Yeah. I was at 176 of your second deposition and I was reading all about Duke Energy Progress stuff and I thought, well, that’s just not right.

A Right.

Q It's the first deposition. And you indicate there that the CAMA amendments with respect to water supply, this is around line 13, 14, was because of a lack of confidence, correct?

A Well, that’s -- yes. That’s what I say here. Now -- and I would also supplement with what I said in my testimony, which is that they failed -- DEC failed to determine the extent of groundwater impacts, reliably establish background concentrations, and perform adequate receptor evaluations.

Q I understand. And, actually, the specific testimony that you gave in your deposition at line 19 was a lack of confidence in DEQ, not DEC. Do you see that?

A Yes, yes.

Q And when I saw that, I thought, well, Mr. Hart was simply mis-transcribed by the court reporter, so I went back and actually listened to the video of the deposition and, in fact, you said DEQ. You may have meant DEC. Or did you, I guess, is my question?

A I -- I think I meant DEC. I believe I meant DEC, and under the context of what I meant by lack of confidence was these issues in my testimony, which is that the extent of groundwater impacts hadn’t been determined, background groundwater concentrations hadn’t been determined, and then inadequate receptor evaluation hadn't been determined.

Q Now, when the General Assembly passed the 2016 CAMA amendments, it did not tell us why it included the alternate water supply requirement in that legislation, did it?

A Not that I’m aware of, no.

Q And you did not survey the members of the

General Assembly who passed the 2016 CAMA amendments to try to find out what motivated them to include the alternate water supply requirement in that legislation, did you?

A I did not.

Q And you did not survey the general public to determine whether it had lost confidence in DEC, did you?

A I did not. It was based upon my experience with working in groundwater for 30 years, and specifically contamination issues related to water supply wells, that it is unheard of that you would have to connect people to a municipal water supply if you hadn't impacted their wells. So it's an extraordinary event, especially within a half mile, you know.

So in my opinion, that was because Duke had failed to determine the extent of groundwater impacts at its facilities, even though they had known for 10 or more years in some cases that they were impacted. They hadn't established background concentrations until fairly recently, which it didn't support their allegation that the concentrations were background. And in some cases they hadn't done an adequate receptor evaluation so they can even know where these water supply wells were until they were required to do so.

Q Well, surveys, Mr. Hart, are a systematic way of gauging public sentiment, are they not?

A Yeah. I think in this case I really wasn't talking about lack of confidence. I may have -- I think I used that term earlier, but I think I may have misspoke when we were talking here in my deposition about -- I think I was talking more about, as I stated in my testimony, that the requirement to hook up people that aren't affected or aren't even reasonably in the path of groundwater contamination to alternate water supplies is an extraordinary measure, and there had to be a reason for that. And, you know, I think it was certainly related to the fact that DEQ had not -- I mean, DEC had not determined the extent of the groundwater impact so that they could go to the public and say these wells are clearly not impacted by our contamination and here's our rationale why, and working with the regulators to show that and get their buy-in on that. That did not happen for my analysis until much more recently.

Q And Mr. Hart, if you turn the page in your deposition, Exhibit 1, to page 178 and on to page 179 as well, you indicate, and particularly at the top of 179, that you, yourself, directly experienced, through press and newspaper articles and things of that nature, the concerns that were out there regarding potential groundwater issues around these plants, correct?

A Yes. It's something that I was certainly interested in as a professional in the field, yes.

Q And you, yourself, had a client in Belmont that asked you to test their water supply well, correct?

A That's correct.

Q And you tested that well, correct?

A Correct.

Q And you found no impact in that well from the coal ash basins at the Allen plant which is also in Belmont, correct?

A Well, we were specifically looking at contamination from a large fill area that Duke had placed on these people's property of coal ash. It was a home for disadvantaged children and adults from the Belmont -- um, home, and so they were very concerned that they had allowed Duke to give them free fill back in the day, and it was all coal ash, and they filled in probably a 30 or 40 foot deep ravine with coal ash, and I believe it was in the hundreds of thousands of tons, and so they were very concerned that that was going to lead to groundwater contamination and this camp was serviced by a water supply well. But we did not find groundwater --

significant groundwater contamination. There was fairly significant surface water contamination that was discharging to Lake Wylie from the coal ash that they had filled onto this property, that Duke had.

Q Okay. But the coal ash fill which was a permitted fill, correct?

A It was permitted, yes.

Q Had no impact on your client’s water supply well, correct?

A No. Just Lake Wylie, which is the water supply for several places.

Q Now, Mr. Hart, look, if you would, at DEC Exhibit 11.

A Okay.

MR. MEHTA: And Chair Mitchell, I would like to have DEC Exhibit 11 marked for identification as DEC Hart Cross Examination Exhibit 7.

CHAIR MITCHELL: All right. The document will be so marked.

MR. MEHTA: Thank you, Chair Mitchell.

(Whereupon, DEC Hart Cross Examination Exhibit Number 7 was marked for identification.)

Q And Mr. Hart, DEC Hart Cross Examination

Exhibit Number 7 is an article in the Charlotte Observer, published at least in the paper-paper on March 9th and online if you go to the back of the last two pages of the exhibit, online published on March 8th, 2016, right?

A That's correct, yes.

Q I think the online piece is a little easier to read, so let's look at that.

A Yes. That's what I have in front of me.

Q And the headline is "NC lifts warnings against drinking well water near Duke Energy ash ponds," correct?

A Correct.

Q And so this is March of 2016, so right at this time, actually, the CAMA amendments were being debated in the General Assembly or were about to be debated in the General Assembly, correct?

A I don't know when they were debated in the General Assembly.

Q But in any event, the article recounts a public outcry when the State of North Carolina shifted gears and reversed an earlier drinking water advisory, said that water in people's wells was good to drink, correct?

A Yes. It said it would rescind the advisory issued last spring after tests found elevated levels of vanadium and hexavalent chromium in private wells.

Q And the article says, if you look at the last page of the exhibit in the second full paragraph, "The state's health and environmental departments sparred for months over the screening levels, internal emails showed, with the environmental agency warning they were too stringent." Do you see that?

A I'm sorry. I lost you.

Q Just look at the very last page of the exhibit.

A Yes.

Q The second full paragraph.

A Oh, I see. Yes, yes. Sorry.

Q And the words "sparred for months" are underlined on the paper version of what we've got here, right, Mr. Hart?

A Correct. And then it says "The departments eventually agreed."

Q Yeah. And I'll represent to you that sparred for months underlined is really a hyperlink when you look at online. And the hyperlink takes you to another article, and that article would be what has been previously marked as DEC Exhibit 12. So if you could get that one in front of you, that would be great.

A Okay.

MR. MEHTA: And Madam Chair, if you -- I would like to have DEC Exhibit 12 marked for identification as DEC Hart Cross Examination Exhibit Number 8.

CHAIR MITCHELL: All right. The document will be so marked.

(Whereupon, DEC Hart Cross Examination Exhibit Number 8 was marked for identification.)

Q And this article, again, Mr. Hart, was published in the Charlotte Observer in January of 2016 prior to the time the CAMA amendments were passed, correct?

A Correct. Yes.

Q And, again, since they're easier to read, we probably should just read the online version which is the last two pages of the article.

A Yes.

Q And the headline there is "Legislators probe conflicting messages on water drinking safety standards," correct?

A Yes, that's what it says. Correct. Yes, that's the title, uh-huh.

Q And if you read the article -- and let me summarize it, you tell me if I'm wrong -- what the legislators were probing, Mr. Hart, was this ongoing fight between the State health agency which issued the water advisory and the DEQ, the environmental agency which wanted it rescinded, correct?

A Well, I mean, yes. So there’s -- the State Health Department had determined a screening level -- I think this one references hexavalent chromium -- and that DEQ had felt that it was “too tough,” but that DEQ eventually consented to the tougher standard, is what it says.

Q Well, actually, Mr. Hart, if the advisory was rescinded, as we saw in the prior exhibit, Exhibit 7, the fight between the DEQ, which wanted it rescinded, and the State Department of Health, which didn’t want it rescinded, was won by the DEQ, correct?

A I mean, it says it was -- in March 8th, 2016 letter it says it was DHHS’ decision to lift the don’t-drink advisory.

Q And DHHS is the health department which issued the advisory, correct?

A Correct. Yes. Health and Human Services, correct.

Q And DHHS rescinded the advisory based on whatever the fight was between DHHS and DEQ, correct?

A It doesn’t say why they did. I’m looking at the article. I don’t see anything in here about why DHHS rescinded the advisory. It just says "followed a meeting Monday in Lee County where coal ash was disposed of in a former clay mine." I don’t know why.

Q Well, if you just keep reading, Mr. Hart, in Exhibit 8, which is the January article --

A Okay.

Q -- the very bottom of the second-to-last page, so the bottom of the -- the online version, says the Department of Health and Human Services is the one that issued the advisory, correct?

A Yes.

Q Then it says in the very next paragraph, which would be the first full paragraph on the last page, the Department of Environmental Quality officials expressed alarm about the screening levels for hexavalent chromium, et cetera; they were too tough, right?

A Correct.

Q And they expressed alarm because public water systems have only to meet a far higher federal standard for total chromium, which includes hexavalent chromium, correct?

A Correct.

Q And the next paragraph, exactly one sentence, says “Conflicting standards, DEQ argued, would mislead the public,” right?

A Correct. That’s what it says.

Q And then it says “DEQ eventually consented to the tougher standard,” that is, it didn’t stand in the way of the advisory, correct?

A Yes. That’s correct.

Q But ultimately, its view that the tougher standard should not be applied prevailed because the advisory was lifted, correct?

A Right. And at the -- yeah -- the end of the January 2016 article says “The health agency will reassess its recommendation when more groundwater test data are reported in the next month.” So, I mean, I think this is a classic case of why you don’t delay addressing your groundwater contamination and determining the extent of it, reliably establishing background levels, and doing receptor evaluations so you can, with confidence, go to the public and the Agency and say we know where our groundwater contamination is, we know it doesn’t extend into these neighborhoods, or if it does, here's where it goes. We have background data. We’ve done background data not only for our site, but regional, which is what ended up happening in some cases. They did a much broader study. And so those -- that's what happens when you address proactively groundwater contamination. When you are reactive to groundwater contamination, this is the kind of thing that happens.

Q Well, are you saying that Duke Energy Carolinas did not undertake steps with the DEQ and the health department to try to address this fight between the DEQ and the health department?

A Well, I mean, they were working on it during this time frame, but, no, they hadn't established the extent of their contamination, they hadn't completed -- they didn't even complete receptor evaluations until required to do so in 2014. And so, you know, if those issues had been addressed before, which is what should have happened, then I think this all could have been avoided.

Q Well, Mr. Hart, why don't we take a look at what was previously marked as DEC Exhibit 14.

A Okay.

MR. MEHTA: And Madam Chair, if we could have this exhibit identified as DEC Hart Cross Examination Exhibit Number 9, that would be great.

CHAIR MITCHELL: All right. The document will be so marked.

(Whereupon, DEC Hart Cross Examination Exhibit Number 9 was marked for identification.)

Q And Mr. Hart, this is another Charlotte Observer article, this one actually postdating the CAMA amendments in October of 2016, right?

A Correct.

Q And, again, just for ease of reading, we can go to the last two pages of the exhibit which are the online versions.

A Yes.

Q And the headline of which is “Coal ash not the source of well contaminant, Duke University study finds,” right?

A Yes. That’s the title, uh-huh, yes.

Q And the lead paragraph, opening paragraph, states “A contaminant at the center of a months-long furor over coal ash and polluted wells doesn’t come from ash after all, Duke University scientists report in a study published Wednesday,” correct?

A Correct.

Q And a couple paragraphs down below says “The state's decision to rescind the health advisories in March,” which was the subject of Exhibit 7, “prompted bitter exchanges among two state health officials, department leaders, and Governor Pat McCrory's office," correct?

A Yes. That's what it says.

Q So Mr. Hart, in coming to your conclusion that the CAMA amendments mandated alternate water supply hookups because of loss of confidence in DEC, how did you eliminate the possibility that what the General Assembly was doing was simply settling a fight within and among two State agencies with overlapping authority over the issue of drinking water safety?

A Well, first of all, I'd say just think if this assessment work about background levels of hexavalent chromium and vanadium had been done a long time ago and has resolved the issue when it should have been done. Because when you have groundwater contamination from metals, yes, it's very important to determine the background concentrations, and so if you go sample water supply wells, you need to find out if they're consistent with background or not. But that hadn't been done yet. And so my belief is if this study or any other study that Duke Energy could have certainly implemented had been done before then, it would have resolved the issue and this wouldn't have been a problem. But it's unheard of to have to connect people that don't have contaminated wells, allegedly from your facility, to municipal water or some sort of supplied water.

Q Well, my question to you, Mr. Hart, was if it's unheard of to be required to connect to municipal water supply wells that are not contaminated or households that are serviced by wells which, in fact, are not contaminated, how do you know that the General Assembly didn't mandate that because it was fed up with its own agencies of the State government as opposed to anything relating to DEC?

A Well, what they're fighting about is whether that DEC -- this is associated with the DEC coal ash problem. So if that had been determined long ago and, for example, at the Allen plant we knew as -- in 2004 that there was groundwater impacts, we knew as early as 1984 that there was groundwater impacts there, and so if the things that had been required to be done under the 2L rules which determine the extent, reliably establish background concentrations, come up with a plan to mitigate the sources, come up with a corrective action plan, do adequate receptor surveys, all that could have been avoided if it was done proactively and not reactively to the Dan River spill.

Q Well, Mr. Hart, if you go back to page 176 of your deposition, Exhibit 1 --

A Okay.

Q -- where you indicate on line 19 a lack of confidence in the DEQ. Do you see that?

A Yes.

Q I'm wondering if that was just a Freudian slip. You actually -- or not a Freudian slip -- you actually meant to say DEQ as opposed to DEC in connection with your answer to my question that you answered on that page and in that paragraph.

A No. I meant DEC, and so I think the court reporter got it wrong. I don't think it was a Freudian slip.

Q Well, actually, I think if you go back and listen to the tape, you said DEQ, but perhaps you didn't mean it.

A Well, it's very easy to run those two together.

MR. MEHTA: Madam Chair, I don't have any further questions for Mr. Hart at this time.

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

(No response.)

CHAIR MITCHELL: All right. Redirect for the witness?

MS. TOWNSEND: Thank you. Just a few questions.

REDIRECT EXAMINATION BY MS. TOWNSEND:

Q First of all, Mr. Hart, I wanted to ask you if you had reviewed the rebuttal testimony of Mr. Lioy, L-I-O-Y -- I’m not quite sure how to pronounce that -- who filed his testimony specifically as a result of your supplemental testimony. Have you had a chance to review that?

A Yes, I did. Yes.

Q And can you give us your opinion of his testimony regarding his remarks about your calculations?

A Well, yeah. In my opinion, it’s -- I certainly understand what he was getting at, and I think the confusion is my use of the term time value of money which probably isn’t a correct accounting term. And, again, I’m not an accountant, but what I was trying to do and what I did was just determine the increase in cost from different periods of time from inflation or the work that’s being done now if it had been started or initiated sooner. And so I understand that maybe time value of money isn’t the right term from an accounting standpoint, but maybe it’s de-escalation from inflation, I’m not sure

what it is, but that's how I read it.
Q Thank you. Also, just to clarify, Mr. Mehta asked you a question about whether or not your decision to add other years was because your client told you to do so. Wasn't, in fact, what happened was that we asked what your testimony would support, and that is when you decided to add the earlier years?
MR. MEHTA: Objection, Madam Chair. Leading.
CHAIR MITCHELL: All right. Restate the question, Ms. Townsend.
MS. TOWNSEND: All right.
Q Again, just to clarify, Mr. Mehta asked you if the reason you used additional years of calculation was based on your client's request; is that correct?
A That's what he asked me, yes.
Q All right. And is that, in fact, the totality of what happened during our discussions?
A Well, we did discuss other dates after we discussed the original, which was the early 2000s to 2009/'10, and, you know, I suggested some other time frames that might also -- well, that would also potentially be appropriate, including some of the early -- late '80s and then also the mid '90s, and I gave some examples of why I chose that in my test--- why I chose

those dates in my testimony.

Q Thank you. And one final question. In your 30 years of experience you've done a lot of -- you've been a witness for many people. Have you ever done similar calculations in other cases?

A Well, yes. I mean, I certainly have looked at the cost of inflation and what that will do to the cost over time and the increase in cost and that -- what that does to the cost, because it will increase the cost over time. Of course, this was a little unique because we're going backwards in time, but nevertheless, if I was -- I think I could say just Ms. Bednarcik yesterday said she could transport herself to 1981 to talk about what a plant manager would do from reading a coal ash publication from the EPA, I think in the same way I was trying to say, well, if I'm here in 2003 and I've got to address these environmental liabilities, what's that going to cost me, and if I wait, how much more is it going to cost me in the future? So it's similar kind of, you know, in my opinion, similar to what I've done before.

Q Thank you.

MS. TOWNSEND: No further questions.

CHAIR MITCHELL: All right. Questions from the

Commissioners, beginning with Commissioner Brown-Bland?

COMMISSIONER BROWN-BLAND: No questions at this time.

CHAIR MITCHELL: Okay. Commissioner Gray?

COMMISSIONER GRAY: No questions at this time.

CHAIR MITCHELL: Commissioner Clodfelter?

COMMISSIONER CLODFELTER: Nothing from me.

CHAIR MITCHELL: All right. Commissioner Duffley?

COMMISSIONER DUFFLEY: I did have one question. It’s just a clarification question.

EXAMINATION BY COMMISSIONER DUFFLEY:

Q So we heard, and I apologize to the witness, witness Bednarcik -- hopefully I have her name correct -- that she stated that there were no water supply wells that were impacted. And if you could turn to page 75 of your testimony, please.

A Okay.

Q And if you could go to line 17 through 19, and you state “A receptor survey conducted in 2014 after the Dan River release indicated a number of water supply wells in the adjacent residential area were impacted.” So are you saying that because of -- do you have any other impacted wells or know of any other impacted wells besides these wells with respect to the Dan River release?

A I'm sorry. I lost where you were. What page were you on?

Q Seventy-five (75).

A So this is -- I'm talking about Allen plant here.

Q Right. And so as I understand your testimony, you're stating after that release that occurred, because the pipe broke, correct, that there were a number of water supply wells that were impacted. And so my question is, besides those wells that you say were impacted in a receptor survey for 2014 related to Dan River, were there any other wells, water supply or -- yeah -- water supply wells that have been impacted?

A So these were near the Allen plant, adjacent to the Allen plant, so the receptor survey was done after the Dan River release, but I am not aware of any others at the DEC facility.

Q Okay. Thank you.

CHAIR MITCHELL: Anything further, Commissioner Duffley?

COMMISSIONER DUFFLEY: Let me see.

Q So on page 12, if you could turn to page 12, I think this is my last question.

A Okay.

Q Okay. If you could -- you have -- read lines 4 through 13, or actually just the first sentence.

A Okay. "DEC's costs are higher today than they would have been had it undertaken reasonable and prudent actions and practices in a timely manner to address storage and disposal of CCR and closure of its coal ash basins before the Dan River spill occurred in 2014."

Q So are you stating that the Company acted imprudently? Is that a conclusion that you're making in this case?

A Yes. It did not -- DEC did not act prudently with regard to how it addressed its knowledge of groundwater contamination associated with its coal ash basins.

Q But just hypothetically, if one were to say that they did act imprudently, my question is can you have -- maybe not have made the perfect 100 percent perfect decision and not be imprudent?

A I'm not sure I understand your question. I mean, there is a process, in my opinion, in how you deal with groundwater contamination issues that's laid out in the 2L rules, and so following that is the prudent course of action, and so that includes defining the extent of the contamination through additional wells, determining the horizontal and vertical extent, determining what the sources are, determining if there are receptors in the area, and then mitigating those risks and inputs to the groundwater system by doing some sort of corrective action, and then ultimately also remediating the groundwater.

And so that's just kind of -- in my opinion, that is the standard of practice as laid out in the 2L rules. To me, that would be the prudent course of action. And, you know, the longer you wait, the longer you delay implementation of those, it's going to cost more, the groundwater contamination can travel further, you're adding mass to the groundwater system, so it will take longer and could be more expensive to remediate.

Q And so the contaminants that are in the coal ash you talk about that travel further, I'm thinking of MTBE. You know, that was a gasoline additive that was removed because it was a leader, a plume leader, right, and it traveled far distances. I'm just interested, what is the distance that these types of contaminants can migrate?

A Well, so most of the metals are not -- don't travel very far because a lot of times they are converted. So, for example, the coal ash basins, as I mentioned before, have very low -- create a very low oxygenated environment in the groundwater which liberates the metals, but as they move downgradient, those conditions may change. The one that is not consistent with it is boron. Boron is not well absorbed onto any particles, and so it usually -- that and chloride -- if you've got chloride issues -- are the ones that can go the furthest. So it really depends on how far they can go. They could go thousands of feet, but it really depends on the distance between the source and a water body, because most groundwater will discharge to the surface water.

Q Okay. So, but from a groundwater perspective, you're saying thousands of feet; is that accurate?

A Well, something like boron could travel that far, and certainly I think in some of the -- at least the DE--- I know some of the Progress sites I've seen boron go that far.

Q And -- sorry. Did not mean to interrupt.

A Well, movement of something like iron and manganese can also go quite a long distance if the conditions that cause the, for example, the low-dissolved oxygen conditions oftentimes persist downgradient for a long distance because the oxygen that's recharging groundwater has all been consumed by the basin itself.

But, I mean, so I don't know -- I didn't really measure distances of groundwater contamination, necessarily, for all the facilities. I was looking at whether they were outside the compliance boundary in a lot of cases, which is 500 feet, so we certainly had in a lot of cases groundwater contamination above 2L standards outside the compliance boundary which would have been at 500 feet or the property line. And that could have been often iron, manganese. It could have also included things like cobalt and arsenic and vanadium in some cases.

Q Okay. Thank you. In answering one of Mr. Mehta's questions, you stated "Requiring water supply well connections is an extraordinary event, especially within a half mile." What did you mean when you said especially within the half mile?

A Well, so normally if you -- so that half mile is -- so groundwater is going to start, and it flows in a specific direction. So the half mile, first of all, that's regardless of whether the well was upgradient or downgradient of the facility. So in some cases they were connecting people that were a half mile away that had no reasonable potential to be impacted from the site. So if they were downgradient and within, you know, I would say, roughly 1,500 feet or so, that might be reasonable. But usually people aren't connected to alternate water supplies unless their well is impacted or it has an imminent threat of being impacted. So a well that's half mile upgradient wouldn't fall into either one of those categories. So that's why I'm saying it's extraordinary that you would just draw a circle around the facility and say this is where you need connect people to municipal water, because it doesn't make much sense from a scientific perspective, which is what we usually look at when we're looking at -- if we need to connect people to well water, those are the kind of things that we'll look at and work with the Agency on. First, are they impacted and, second, do they have the potential to be affected?

Q Okay. And let me make sure that I heard your answer correctly. The downgradient wells, you're saying that a well within 1,500 -- what did you -- what denomination did you use?

A Feet.

Q Yeah -- 1,500 feet could potentially be impacted, but you don't think that a receptor within a half mile of that plume would be affected; is that what I heard?

A Well, I would say in general, but, you know, every site is a little bit different. So, I mean, you could have a well that's a half mile downgradient of an ash basin or another source and have the potential to be impacted. That would be unusual because in most cases you have a stream within a half mile. And so generally groundwater doesn't cross a stream, so -- and, of course, a number of these facilities where most of them were adjacent to water bodies, and so in most cases the groundwater contamination traveled to the water body and then discharged to Dan River or Lake Wylie or one of those service water bodies. They didn't tend to get go very far in most cases, although certainly outside the compliance boundaries.

Q Okay. And actually I did have one more question. If you could turn -- and I just would like to get your interpretation. If you could turn to your Exhibit Number 11.

A Okay.

Q So I think Mr. Mehta asked you about this as well, this letter. And so I'm just trying to understand your testimony because I do understand that 2L requires certain requirements, but -- and you stated that, you know, that your testimony is Duke did not meet the letter of the law requirements of 2L, but I guess in looking at this December 18th, 2009 letter, if you look at that last paragraph.

A Okay.

Q So it says in light of concerns brought up by your staff in past discussions about combining the compliance boundaries of adjacent, you know, permitted activities is going to be encouraged, and then the letter goes on site by site to make recommendations about monitoring wells. So wasn't Duke working with the regulators on these monitoring wells?

A Well, starting in 2010, I would say they did start working with them with regard to looking at where to put additional wells. So before that, with regards for like the USWAG sampling that was started, and it was started as a voluntary program, but it was a commitment from the Utilities group that if they found contamination, they would implement corrective actions, and so they did do some of that monitoring and they just sent -- as far as I can tell from the information we have, they just sent the data to DEQ without any information about whether it was above or below the 2L standards or where the wells were in relation to the compliance boundary with a background or downgradient, and then implied in their cover letters that the data were consistent with background, which wasn't true, in my opinion.

And so it wasn't until DEQ looked at all this information they had been receiving from DEC in 2009 and asked for, hey, we've been getting all this data from you from this USWAG program; we need to find out more information. We need maps. We need -- you need to put in some more wells. We need to know where the compliance boundaries are. You need to analyze regardless of constituents. And that's when they started to kind of at least get DEQ's input or address it with DEQ, is around the 2010 time frame. And then they did put in some more wells, which showed -- at the compliance boundary which showed even greater -- I mean, did show that there was issues at the compliance boundaries, and then really didn't do anything until the Dan River spill in 2014, and that's when they, you know, were required to start doing full investigations of the sites. But certainly the 2L rules were clear, that if you have groundwater exceedances and violations, that this is the process you should take.

Q Okay. Thank you, Mr. Hart.

COMMISSIONER DUFFLEY: I have nothing further.

THE WITNESS: Thank you.

CHAIR MITCHELL: All right. Mr. Hart, I'm going to follow up on Commissioner Duffley's --

COMMISSIONER HUGHES: I'm sorry. Did you call my name? I'm sorry.

CHAIR MITCHELL: No, not yet. I was going to ask Mr. Hart a question.

COMMISSIONER HUGHES: Okay.

CHAIR MITCHELL: And then I'll -- and then I'll call -- then I'll call on the remaining Commissioners.

EXAMINATION BY CHAIR MITCHELL:

Q I just want to follow up a question that Commissioner Duffley asked, Mr. Hart. And you've explained sort of the USWAG voluntary activities that the Company was undertaking at its sites. Seems like that was kind of the early -- early '80s time period -- I mean, I'm sorry -- the early 2000s. And then I think your testimony, and correct me if I'm wrong -- this is what I've heard just now in response to Commissioner Duffley -- is that in the 2009/2010 time frame, as evidenced by that letter that you attached as Exhibit 11 to your testimony, DEQ initiated discussion with the

Companies, indicating that some additional investigative activities needed to be undertaken. So when should -- help me understand the point in time at which the Company should have done more, because from what I can tell, it was involved with DEQ beginning in 2009 and it was doing the voluntary USWAG work prior to then, so just -- I just want you to sort of nail it down for me.

A Well, yeah, and I think it depends on the facility. I think, you know, where they've been doing groundwater monitoring at Dan River and -- let me get it right -- well, in H.S. Lee, where they had groundwater monitoring dating back to 1993, there were certainly indications of impacts at those facilities. And so I think at least by the, you know, late '90s to early 2000s, after they obviously wouldn't, in most cases, act on data if you only had one or two sampling events; they usually developed some data set initially, and then start investigating the horizontal and vertical extent and determining how we're going to deal with these groundwater contamination issues.

You know, the other facilities -- well, other than Allen, which had some monitoring going on in the 1980s, although I think, you know, you could certainly make a case that at Allen, you know, as early as the early 1980s they should have been doing something to address the groundwater contamination. That might be a little aggressive, so, you know, I think from there most places, you know, once they did the USWAG monitoring, which ranged anywhere at Allen from 2004 until Riverbend in 2008, and also Cliffside, you know, which showed very significant groundwater contamination issues, at least within the compliance boundary, that should have been the trigger to go to DEQ, tell them the issues we have, and start the process of finding the extent of contamination, and then addressing how we -- how are we going to address these issues.

We know in 2003 from Duke documents that they were certainly aware of the changing regulatory landscape and that they might not be able to use coal ash basins because of the groundwater contamination concerns from their 10-year report in 2003. In 2007 they talk about, you know, certainly the possibility that they won't have -- they won't be able to use these basins forever. And so, you know, other than Dan River and H.S. (sic) Lee, I would, you know, generally when they had done the USWAG monitoring and had a few years' worth of data, they -- it should have triggered a substantial investigation and evaluation of how we're going to address this problem, which potentially included dry ash conversions to eliminate the source, getting rid of all the other sources of water that they had conveniently disposed in these basins for long periods of time that really aren't coal ash related. In fact, there was some question about whether they were hazardous waste, but they were covered under the Bevill Amendment and so were not. And so I would -- hope that answers your question.

Q It does. Thank you.

CHAIR MITCHELL: All right. Commissioner Hughes?

COMMISSIONER HUGHES: Yes. Thank you.

EXAMINATION BY COMMISSIONER HUGHES:

Q I had a question or two about the economic impact analysis that you did. And if I understand it, you have two ways of talking about the customer impact. You have itemized a number of things that you postulate that would have been cheaper if Duke had done it earlier, and then you have this separate time value of money calculation. I think I understand the first part, so what you're saying is that it wouldn't have cost three hundred and for--- if you use your numbers, it wouldn't have cost $341 million. It probably would have cost less. And if you move that all the way back into 1989 dollars, then it would have been less than 175 million. So I think I -- is that correct to -- if you moved it back --

A Yes.

Q -- to $189 (sic) -- you don't give a number, but it could have been 150, 125, 100 million, something like that, back in -- is that -- am I following that part of your analysis?

A Yes. That's correct. Yes.

Q So I understand that. The time value of money I'm having a harder time with for some other reason --

A So that is the time value of money.

Q Pardon me?

A That is what I call the "time value of money," quote, unquote.

Q Well, I understand -- I understand the difference between something that would have cost 125 million in 1989 dollars versus 170 million, because from a Duke customer impact, that's -- the Duke customer impact is -- was pretty significant. Just to use your approach, would you say that customers would have less of an impact if something had cost $300 million in 1989 to do versus three hundred and for--- let's say 325 -- if something cost $325 million in 1989 dollars, but move --

if you move forward and it costs $341 -- $341 million in today's dollars, would you say that the customers would have been better off with a $325 million expenditure way back in 1989? I mean, because that's a, you know, that's still like a $16 million savings from your approach.

A Well, I mean, if you had 1989 dollars, 325 million, I don't know. I don't know exactly how rates are made. I can say that the people that were benefiting from the power at the time that were using the power that was obtained from coal-fired power plants would have benefited much more than somebody today where that facility is shut down.

And so if you have a customer today that is paying for coal ash remediation and they got no benefit from it, certainly, the customer in the past would have been much more benefited than the customer today, regardless of price. I don't know if I answered your question, but --

Q Well, I -- it's a different -- it's a different answer.

A Yeah.

Q I'm really concerned about the time value analysis that you presented because it just seems like the customer base would be better off today spending 341 million than spending 325 million in 1989, and the way you presented it, it seems to be saying that any difference between comparing 1989 dollars and 2018 dollars, any difference is beneficial to the customers, and I don’t see that in the way that you would look at the value of money.

A Well, yeah. I think if it’s 325 million, no, because obviously 1989 dollars, 325 million is going to be more than 342 million today, right, but anything less than 171 million, which was -- which was potentially possible for coal ash remediation back in 1989 because you had other options of dealing with the coal, you wouldn’t have had a beneficiation. It wouldn’t have occurred because it wasn’t a viable technology. It’s by far the most expensive. In fact, Duke’s own studies show that it’s by far the most expensive recycling process, and you have to build a $100 million plant and operate it for 20 years, and so you wouldn’t have something like that. And then you also, you know, would have potentially had the option to close a lot of these basins in place rather than fully excavate them in place. And certainly, that was going on in some facilities in North Carolina, not necessarily power plants, but there were people that were doing that, and they haven’t had to excavate them, you know, since.

So I think there was much lower cost options available in 1989 than there were today, and that's why when I did my analysis, I said, well, absolutely the most expensive options are being used today, and so that's why I felt it was appropriate to scale those back to 1989 dollars. I understand what you're saying, but to me it couldn't have cost any more than 171 million, or it should have cost less than that because there were much more lower cost alternatives available than have been selected now.

Q Right. I understand. Anything less than $171 million back in 1989 is clearly a benefit to the customers.

A Right.

Q Okay. Thank you.

A Yes. Thank you.

CHAIR MITCHELL: All right. Commissioner McKissick?

COMMISSIONER McKISSICK: I don't have any questions at this time. Thank you.

CHAIR MITCHELL: All right. At this time we are going to take a break for the court reporter. Let's go off the record. We'll go back on at 3:50.

(Recess taken from 3:40 p.m. to 3:50 p.m.)

CHAIR MITCHELL: All right. We will proceed with questions on Commissioners' questions. Let's go back on the record, please. All right. Questions on Commissioners' questions?

MR. MEHTA: DEC has no questions, Chair Mitchell.

CHAIR MITCHELL: All right. Thank you, Mr. Mehta.

CHAIR MITCHELL: Any questions from the Public Staff?

MS. LUHR: Nothing from the Public Staff.

CHAIR MITCHELL: Other intervening parties?

(No response.)

CHAIR MITCHELL: All right. Attorney General's Office?

MS. TOWNSEND: Yes. Just a couple questions.

EXAMINATION BY MS. TOWNSEND:

Q Mr. Hart, Commissioner Duffley asked you a question regarding your Exhibit Number 11, if you could pull that back up.

A Yes. I have it up.

Q All right. In the last sentence, or last paragraph which the two of you discussed, it said, "In light of concerns brought up by your staff in past discussions, combining compliance boundaries for adjacent DWQ permitted activities will be allowed, as well as encouraged." There was some inference based on that language that DEQ and DEC were actively involved in discussions; is that correct?

A Yes, yes.

Q All right. If we go to the first paragraph of that letter, the second sentence says "Based on the review of the submitted data, specific recommendations and additional information requests on a site-by-site basis are attached," correct?

A Yes, yes.

Q All right. And if we go to the first attachment, which would be the third page of that exhibit, which refers to Allen Steam Station, Attachment 1. Do you see that?

A Yes, yes.

Q All right. And under Hydrogeology, the very first thing they say is that based on the supplied maps, monitoring wells, and they list quite a few, are located inside the review/compliance boundaries, and it says these wells are not suitable for determining compliance; is that correct?

A That's correct, yes.

Q So prior to this time, there were no -- these wells, at least, were not at the compliance boundary; is that correct?

A At this time, no -- well, yes, those wells were not at the compliance boundary. I believe the Allen, though, was the well that was installed at the compliance boundary in 2004 which showed impacts, but, you know, what, DEQ is saying is we need to install more wells at the compliance boundaries --

Q Okay. The third one?

A -- on these particular wells, yes.

Q Okay. In fact, the third bullet talks about based upon a clarification of the 2L rules, monitoring wells are now required to be located at the compliance boundary, so that requirement was established, evidently, around the 2009 date of this letter; is that correct?

MR. MEHTA: Objection. Leading.

CHAIR MITCHELL: All right. Ms. Townsend, restate the question.

Q What I'm asking is based on the third bullet, what is your interpretation of what was occurring at that time in 2009?

A In 2009, DEQ was asking that monitoring wells

-- well, that they were required to be installed at the compliance boundary. In the past, for the most part, wells had not been installed at the compliance boundary, and DEQ is saying the only way -- the way we determine compliance with the 2L standards is to put wells in at the compliance boundary since you have indications of wells which are inside the compliance boundary that there are groundwater contamination issues.

Q And if we go to bullet 5, does that deal with the last paragraph on page 1 of the letter?

A Yes. I think what they're -- yeah. So I think what that last -- well, I know what that last paragraph in the letter is doing, that I was asked about previously, is about combining -- if there were adjacent coal ash basins, could they combine the compliance boundaries around them so they basically only had one compliance boundary and not a compliance boundary around each facility. In other words, you don't, you know, have a compliance boundary that might go through another ash basin. They can combine them all into one big compliance boundary for all the permitted units.

Q All right. If you would, if you look at each of the other attachments for each of the various sites, do you find the same reference to the fact that there are wells that they consider not suitable for determining compliance?

A I believe that is the case, yes. I will check.

MS. TOWNSEND: No further questions. Thank you.

CHAIR MITCHELL: All right. I'll entertain motions at this time.

MR. MEHTA: Chair Mitchell, I would move the introduction into evidence of DEC Hart Cross Examination Exhibits 1 through 9.

CHAIR MITCHELL: All right. Hearing no objection to your motion, Mr. Mehta, it will be allowed.

MR. MEHTA: Thank you, Chair Mitchell.

(Whereupon, DEC Hart Cross Examination Exhibit Numbers 1-9 were admitted into evidence.)

CHAIR MITCHELL: All right. Mr. Hart, you may step down. Thank you very much for your testimony today, sir.

MS. TOWNSEND: Thank you. Further, we would also introduce the cross examination exhibits into the record from the DEC case, which consisted of, according to my records, DEC Hart Cross Examination Exhibits 1 through 9.

COMMISSIONER CLODFELTER: All right. Those are the only exhibits that are being moved at this time, correct?

MS. TOWNSEND: That's correct.

COMMISSIONER CLODFELTER: Okay. You've heard the motion from Ms. Townsend. Are there any objections?

(No response.)

COMMISSIONER CLODFELTER: If not, motion is allowed.

(DEC Hart Cross Examination Exhibits 1 through 9 from Docket E-7, Sub 1214 were admitted into evidence.)

MS. TOWNSEND: Thank you, Commissioner Clodfelter. Mr. Hart is now available for cross examination.

COMMISSIONER CLODFELTER: Okay. Mr. Mehta?

MR. MEHTA: Yes, sir. Thank you,

Commissioner Clodfelter.

CROSS EXAMINATION BY MR. MEHTA:

Q. And good afternoon, Mr. Hart.

A. Good afternoon.

Q. We probably, since we may refer to them during the course of this examination, have available to you what was premarked as Cross Exhibit -- DEP Cross Exhibit Number 6, which is a copy of your deposition transcript, and premarked as DEP Cross Exhibit Number 5, which are your work papers for the DEP analysis.

A. Okay.

MR. MEHTA: And, Commissioner Clodfelter, I will try to get this right. For DEP Cross Exhibit 6, which is the deposition transcript, if we could have that identified for the record as Hart DEP Cross Examination Exhibit Number 10, that would be awesome.

COMMISSIONER CLODFELTER: Awesome, indeed, because I think you got it right. It will be so designated.

(Hart DEP Cross Examination Exhibit Number 10 was marked for identification.)

MR. MEHTA: And for DEP Exhibit 5, which are Mr. Hart's work papers, we will please have those identified as Hart DEP Cross Examination Exhibit Number 11.

COMMISSIONER CLODFELTER: Mr. Mehta, it will be so designated.

MR. MEHTA: Thank you, Commissioner Clodfelter.

(Hart DEP Cross Examination Exhibit Number 11 was marked for identification.)

Q. Mr. Hart, in the -- in this case, the DEP case, unlike the DEC case, you did not need to file supplemental testimony regarding your efforts to quantify your proposed cost disallowance; is that correct?

A. That is correct.

Q. And in Hart DEP Cross Examination Exhibit 11, your DEP work papers, the work papers show how you went about doing the quantification that you proposed in the DEP case; is that correct?

A. Yes. Yes. It's a summary of the method and the specific amounts that I used in quantifying that amount, yes.

Q. And you -- you basically have three steps in your method; is that correct?

A. That's correct.

Q. And the first, which you call step A, is the removal of permanent water supply costs from the costs sought for recovery by DEP in this case, correct?

A. That is correct.

Q. And you did exactly the same thing in your DEC supplemental testimony, correct?

A. That's correct.

Q. And you performed that calculation in the same manner and for the same reasons as you did in your DEC testimony; is that correct?

A. That is correct.

Q. So we have no reason to go over it as part of this testimony, because it will all come in through the stipulated testimony.

Now, your step -- what you call step B is removal of what you called, quote, old, close quote, ash basin costs, correct?

A. That is correct, yes.

Q. And this is an entirely new step not included in your DEC analysis; is that right?

A. That is correct.

Q. Okay. We'll come back to back to that one.

I'm curious, Mr. Hart, in the -- in the DEC testimony, which is now stipulated into the record, there was reference to going back to the '80s and '90s in your time value of money analysis, and that that was done at the suggestion of the Attorney General; do you recall that testimony?

A. Well, back to the -- yes, back to an earlier time period than I initially came up with, yes.

Q. Right.

A. I do recall that.

Q. I was just wondering if your step B was also done at the suggestion of the Attorney General?

A. No. No. That was my idea and something I pointed out to them, that the basins at the Duke Energy Progress facilities were much different than those at the Duke Energy Carolinas. Duke Energy Carolinas primarily filled in old stream valleys, and so they had very large ash ponds that would last a long period of time. And so in most cases, the ash ponds, even though they may have done some raising of dikes to increase the capacity of the ash ponds, for the most part -- I think there was only one facility that had an ash pond that was out of use and just sitting there that -- in current or recent times.

Whereas, Duke Energy Progress had what I would call discrete constructed ash ponds that were, in most cases, although there were a few facilities that did have valley fill ash basins, for the most part they were ash basins that were dug out, and then they were filled with ash and allowed to fill, and then were basically abandoned after they were functional and full.

So it was a different companies, different methods of addressing their coal ash basins. There was a few facilities, like I said, where they did fill in some valleys. So it wasn't completely different. But for the most part, DEP had individual basins that they'd fill up, and once they were functionally full, they stopped using them. And so they were -- in most cases they were fairly small, and in most cases a lot of the DEP facilities were limited in the size of the amount of land they had. So they didn't have 400-acre ponds like in some cases at the DEC facilities.

Q. All right. As I said, we'll come back to your step B. Let's just go on to step C for a second.

A. Okay.

Q. And step C -- in step C you employed the time value of money analysis that you also employed in the DEC case, correct?

A. Yes. Similar analysis for the costs that hadn't been excluded in steps A and B; that's correct.

Q. And for the time value of money analysis that you employed in the DEP case, the current case, you followed the same methodology as for the DEC case, correct? Albeit that you used different time periods going back in the past, but the methodology was the same, correct?

A. That's correct.

Q. So again, I think we examined that methodology in some detail in the DEC case, and there's no reason to go back over that again today. So let's, then, go back to what you have that is new, Mr. Hart, which is your step B dealing with the -- what you call the old ponds.

And if I understand it correctly, and correct me if I'm wrong, the theory underlying your disallowance of the, quote, old basin costs, is that those basins should have been closed when they became inactive back in the 1980s or at some earlier point in time; have I captured that correctly?

A. Yeah, I'd say, in a general sense, that's correct. They should have undergone some closure to minimize the amount of rainwater that continued to infiltrate into the basins leading to continued groundwater contamination. But also it just seems, from my analysis, that today's ratepayers shouldn't have to pay for closure of an ash basin that was taken out of service in 1960s to 1980s for which they draw no benefit.

Q. Well, now, Mr. Hart, I believe in your DEC testimony, you acknowledge that you're not an expert in ratemaking, correct?

A. That's correct.

Q. You didn't become an expert in ratemaking between the time you filed your DEC testimony and the time you filed your DEP testimony, did you?

A. No, I did not.

Q. So did somebody tell you that it was not reasonable, from the rate-setting perspective, to conclude that today's ratepayers should not bear those?

A. Well, again, it just seems like a cost that should have been dealt with in the 1960s to the 1980s, from my perspective. And it would have potentially addressed many of the groundwater contamination issues we're seeing today at those old basins. But there was no effort, from what I can tell, to close those basins out.

In fact, most of those -- many of those basins, including things like the lay of land areas, were never permitted. And therefore, they don't even qualify, in my opinion, for a compliance boundary designation, because they were never permitted facilities. A compliance boundary only applies to permitted facilities. Many of these ash basins were never permitted under an NPDES permit.

Q. Now, when you talk about these old basins -- and I think, in order to save time, whenever I say "old," Mr. Hart, just assume there's quotes around them, around the word "old." That way I don't have to say "quote old," and we'll just know what we're talking about; is that okay with you?

A. Yes. That's fair, yes.

Q. Okay. So just using the Asheville one, for example, you say, on page 169 of your testimony, that the 1964 ash pond was out of service in 1982; it is that correct?

A. What page are you on, sir?

Q. 169 of your DEP testimony.

A. (Witness peruses document.)
Yes. Out of service in 1982, correct.
Q. But was the 1964 basin still in use after 1982 for purposes of stormwater handling, or wastewater treatment, or any of those purposes?
A. Well, I think as I indicated earlier in my -- in this testimony, that it was used occasionally for -- let's see what I said.
(Witness peruses document.)
That there was stormwater -- I'm sorry, I'm looking at the '64 basin, sorry.
The ash basin continued to receive stormwater discharge but did not have an outflow, so any stormwater that went into it seeped into the ground or evaporated. So it was -- I mean, yes, it was being used for something, but certainly there was no reason they couldn't have put a stormwater basin somewhere else. It was just a convenient place to put it.
But it was out of use. In fact, it doesn't even show up in some of the NPDES permits until later on. So it wasn't even -- at some point, it wasn't even a permitted facility.
Q. By the same token, Mr. Hart, I mean, didn't the, quote, old ash basins at Sutton and the Roxboro

plants continue to be used for those same types of purposes, stormwater -- stormwater handling and things of that nature after they were -- after they had come in at if for the purpose of sluicing ash?

A. Some were, although it's unclear. Sounds like they used them occasionally at some of the other facilities when, for example, a repair or maintenance was done on the facility or the dry ash handling system may have been down. So they may have served some minor component, but there's no reason why they couldn't have been closed out beforehand just to handle stormwater for a brief period of time. You don't keep a 1963 ash basin open -- closed out in 1963 just so we can receive stormwater. That seems -- and it's going to continue to increase the head and drive contamination into the groundwater.

What happened was these basins just became a place to -- a convenient location to place waste without any thought about what it was doing to the groundwater. And you see that in the groundwater data. They -- at Asheville, they started to put FGD waste in there, into the 1964 basin for a period of time, and you can see a sharp increase in the concentration of boron after that occurred. So these were just, like, convenient places to place wastewater without any thought about what they were doing them, even though they were out of use.

A lot of them didn't have any place to discharge. So all that water that was being put in those basins, it didn't overflow into the river like the permitted facilities did, it just infiltrated into the ground.

Q. Well, Mr. Hart, I believe the Sutton -- old Sutton basin was one that was used from time to time when there was maintenance that occurred with respect to the new Sutton basin, correct?

A. Well, it operated -- I show it was operating until 1985, and then it was temporarily used again in 2011. So for 26 years it sat there vacant until somebody decided to use it as a convenient place to dump some wastewater.

Q. And if it wasn't in existence in 2011, Duke Energy Progress would have had to do something else to deal with the ash that was being sluiced -- otherwise, would have been sluiced to the new basin when they were doing the maintenance work that they were required to be doing on the new basin, correct?

A. It would have had something to do -- yes.

Just like they've had to do it now. But if they had done it previously, they would have avoided the continued groundwater contamination from these basins, and they could have addressed these issues at the time. And there's no reason why you can't use like a rim-ditch system or something to remove materials for a short period of time and then excavate them without just placing it into the basin. I mean, the thing sat idle for 26 years so that it could be used again for a year while the system was down.

MR. MEHTA: Commissioner Clodfelter, it's 12:29. I'm not finished. I don't know whether you want to stop for lunch now and pick up after lunch or keep going.

COMMISSIONER CLODFELTER: Mr. Mehta, let's do that. I'm not surprised that you're not finished, and don't know that we'll get to a stopping point anytime soon. So let's go ahead and take our lunch break at this point, at your suggestion, and we will reconvene at 12:30 when we take our recess -- excuse me, at 1:30. When we take our recess, if you'll please remember to mute your mics and turn off your video. Thank you. We'll be back at 1:30.

MR. MEHTA: Thank you.

(The hearing was adjourned at 12:30 p.m. and set to reconvene at 1:30 p.m. on Wednesday, September 30, 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 5th day of October, 2020.

JOANN BUNZE, RPR
Notary Public #200707300112